IMPORTANT NOTICE

You must read the following disclaimer before continuing. The following disclaimer applies to the attached Offering Memorandum (the "Offering Memorandum"). You are therefore advised to read this disclaimer carefully before reading, accessing or making any other use of the attached. In accessing the attached, you agree to be bound by the following terms and conditions, including any modifications to them from time to time, each time you receive any information from us as a result of such access.

THE SECURITIES HAVE NOT BEEN, AND WILL NOT BE, REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), OR THE SECURITIES LAWS OF ANY OTHER JURISDICTION AND MAY NOT BE OFFERED OR SOLD WITHIN THE UNITED STATES OR TO, OR FOR THE ACCOUNT OR BENEFIT OF U.S. PERSONS (AS DEFINED UNDER REGULATION S UNDER THE SECURITIES ACT), EXCEPT PURSUANT TO AN EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT AND ANY APPLICABLE STATE OR LOCAL SECURITIES LAWS.

Restrictions: The attached Offering Memorandum is being furnished in connection with an offering exempt from registration under the Securities Act solely for the purpose of enabling a prospective investor to consider the purchase of the securities described in the Offering Memorandum. The materials relating to the offering do not constitute, and may not be used in connection with, an offer or solicitation in any place where offers or solicitations are not permitted by law.

Except with respect to eligible investors in jurisdictions where such offer is permitted by law, nothing in this electronic transmission constitutes an offer or an invitation by or on behalf of either the issuer of the securities or Citigroup Global Markets Inc., Crédit Agricole Corporate and Investment Bank, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd., and Mizuho Securities Asia Limited (the "Dealers") to subscribe for or purchase any of the securities described therein, and access has been limited so that it shall not constitute a general advertisement or general solicitation (as those terms are used in Regulation D under the Securities Act) or directed selling efforts (within the meaning of Regulation S under the Securities Act) in the United States or elsewhere. If a jurisdiction requires that the offering be made by a licensed broker or dealer and the Dealers or any affiliate of the Dealers is a licensed broker or dealer in that jurisdiction, the offering shall be deemed to be made by the Dealers or such affiliate on behalf of the issuer in such jurisdiction.

You are reminded that you have accessed the attached Offering Memorandum on the basis that you are a person into whose possession the Offering Memorandum may be lawfully delivered in accordance with the laws of the jurisdiction in which you are located and you may not nor are you authorized to deliver or forward this document, electronically or otherwise, to any other person. If you have gained access to this transmission contrary to the foregoing restrictions, you will be unable to purchase any of the securities described therein.

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THE ATTACHED OFFERING MEMORANDUM MAY NOT BE FORWARDED OR DISTRIBUTED TO ANY OTHER PERSON AND MAY NOT BE REPRODUCED IN ANY MANNER WHATSOEVER. ANY FORWARDING, DISTRIBUTION OR REPRODUCTION OF THIS DOCUMENT IN WHOLE OR IN PART IS UNAUTHORIZED.

The attached document has been made available to you in electronic form. You are reminded that documents transmitted via this medium may be altered or changed during the process of transmission and consequently neither the issuer of the securities and the Dealers nor any of their employees, representatives or affiliates accepts any liability or responsibility whatsoever in respect of any discrepancies between the document distributed to you in electronic format and the hard copy version. We will provide a hard copy version to you upon request.

Confirmation of Your Representation: You have accessed the attached document on the basis that you have confirmed your representation that (1) you and any customers you represent are (i) qualified institutional buyers (as defined under Rule 144A under the Securities Act), or (ii) neither resident in the United States nor a U.S. person (as defined under Regulation S under the Securities Act) and that the electronic mail address that you gave us and to which this e-mail has been delivered is not located in the United States, (2) you consent to delivery of the attached Offering Memorandum and any amendments or supplements thereto by electronic transmission and (3) you agree to the foregoing terms and conditions.

Supplemental Offering Memorandum to the Offering Memorandum dated July 23, 2019



PT PERTAMINA (PERSERO)

(a state-owned company established in the Republic of Indonesia with limited liability)

US$10,000,000,000
Global Medium Term Note Program

This supplemental offering memorandum (the "Supplemental Offering Memorandum") is a supplement to, and is to be read together with, the attached offering memorandum dated July 23, 2019 (the "Original Offering Memorandum" and, together with this Supplemental Offering Memorandum and as may be further amended or supplemented from time to time, the "Offering Memorandum") relating to the US$10,000,000,000 Global Medium Term Note Program (the "Program") of PT Pertamina (Persero) (the "Issuer"), a state-owned company established with limited liability under the laws of the Republic of Indonesia. To the extent that the Original Offering Memorandum is inconsistent with this Supplemental Offering Memorandum, this Supplemental Offering Memorandum shall prevail. Terms defined in the Original Offering Memorandum shall bear the same meanings in this Supplemental Offering Memorandum unless specified otherwise herein. Under the Program, the Issuer, may, from time to time, subject to compliance with all relevant laws, regulations and directives, issue notes in bearer or registered form (the "Notes").

The maximum aggregate principal amount of all Notes from time to time outstanding under the Program will not exceed US$10,000,000,000 (or its equivalent in other currencies determined at the time of agreement to issue), subject to any duly authorized increase. The Notes may be denominated in U.S. dollars, Euros and such other currencies as may be agreed between the Issuer and the Relevant Dealers (as defined below), subject to all legal and regulatory requirements applicable to issuances of Notes denominated in particular currencies. The Notes may bear interest on a fixed or floating rate basis, be issued on a fully discounted basis and not bear interest, or be indexed.

The Notes may be issued on a continuing basis to the Dealers and any additional Dealer(s) appointed under the Program from time to time pursuant to the terms of an amended and restated program agreement dated October 19, 2018 as amended by an amendment agreement dated as of July 23, 2019 (as the same may be further amended, supplemented or restated from time to time, the "Program Agreement"), which appointment may be for a specific issue or on an ongoing basis (each, a "Dealer" and, together, the "Dealers"). References in the Offering Memorandum to the "Relevant Dealer," in the case of an issue of Notes being (or intended to be) subscribed by more than one Dealer, shall be to all Dealers agreeing to subscribe for such Notes.

Notes will be issued in Series (each, a "Series"), with all Notes in a Series having the same maturity date and terms otherwise identical (except in relation to issue dates, interest commencement dates, issue prices and related matters). Notes of each Series may be issued in one or more tranches (each, a "Tranche") on different issue dates. Details applicable to each particular Series or Tranche will be supplied in a pricing supplement to the Offering Memorandum (each, a "Pricing Supplement"), which will contain the aggregate principal amount of the Notes, interest (if any) payable in respect of Notes, the issue price of Notes and any other terms and conditions not contained herein which are applicable to each Tranche. The Offering Memorandum may not be used to consummate sales of Notes, unless accompanied by a Pricing Supplement.

The price and amount of Notes to be issued under the Program will be determined by the Issuer and the Relevant Dealer at the time of issue in accordance with prevailing market conditions.

Application has been made to the Singapore Exchange Securities Trading Limited (the "SGX-ST") for permission to deal in and for the listing and quotation of any Notes that may be issued pursuant to the Program and which are agreed at or prior to the time of issue thereof to be so listed on the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained herein. Admission of any Notes to the Official List of the SGX-ST is not to be taken as an indication of the merits of the Issuer and its respective subsidiaries and associated companies, the Program or the Notes. Unlisted Notes may be issued under the Program. The relevant Pricing Supplement in respect of any Series will specify whether or not such Notes will be listed and, if so, on which exchange(s) the Notes are to be listed. There is no assurance that an application to the SGX-ST for the listing of the Notes of any Series will be approved.

Notes of each Series to be issued in bearer form ("Bearer Notes") will initially be represented by interests in a temporary global Note or by a permanent global Note, in either case in bearer form (each a "Temporary Global Note" and a "Permanent Global Note," respectively), without interest coupons, which may be deposited on the relevant date of issue (the "Issue Date") with a common depositary on behalf of Clearstream Banking, société anonyme ("Clearstream") and Euroclear Bank S.A./N.V. ("Euroclear") (the "Common Depositary") or any other agreed clearance system compatible with Euroclear and Clearstream and will be sold in an "offshore transaction" within the meaning of Regulation S ("Regulation S") under the United States Securities Act of 1933, as amended (the "Securities Act"). The provisions governing the exchange of interests in Temporary Global Notes and Permanent Global Notes (each, a "Bearer Global Note") for other Bearer Global Notes and individual definitive Bearer Notes ("Definitive Bearer Notes") are described in "Forms of the Notes." Definitive Bearer Notes will only be available in the limited circumstances as described herein.

Notes of each Series to be issued in registered form ("Registered Notes") sold in an offshore transaction will initially be represented by interests in a global unrestricted Note, without interest coupons (each an "Unrestricted Global Security"), which may be deposited on the issue date with the Common Depositary unless otherwise specified in the applicable Pricing Supplement. Beneficial interests in an Unrestricted Global Security will be shown on, and transfers thereof will be effected only through, records maintained by, Euroclear or Clearstream unless otherwise specified in the applicable Pricing Supplement. Notes of each Series sold to a qualified institutional buyer ("QIB") within the meaning of Rule 144A under the Securities Act ("Rule 144A"), as referred to in, and subject to the transfer restrictions described in, "Plan of Distribution" and "Transfer Restrictions" will initially be represented by interests in a global restricted Note, without interest coupons (each a "Restricted Global Security" and together with any Unrestricted Global Security, the "Registered Global Securities"), which will be deposited on the relevant issue date with a custodian for, and registered in the name of a nominee of, The Depository Trust Company ("DTC"). Beneficial interests in a Restricted Global Security will be shown on, and transfers thereof will be effected only through, records maintained by DTC and its participants. See "Global Clearance and Settlement Systems" in the Original Offering Memorandum.

Notes in definitive registered form will be represented by registered certificates (each, a "Certificated Security"), one Certificated Security being issued in respect of each Noteholder's entire holding of Notes of one Series and will only be available in the limited circumstances as described herein.

Notes of any Series issued under the Program may be rated or unrated. When an issue of Notes is rated, its rating will not necessarily be the same as the rating applicable to the Program. A security rating is not a recommendation to buy, sell or hold securities and may be subject to suspension, reduction or withdrawal at any time by the assigning rating agency.

Investing in the Notes involves risk. See "Risk Factors" beginning on page 21 of the Original Offering Memorandum and the Supplemental Risk Factors beginning on page S-7 of this Supplemental Offering Memorandum for a discussion of risks relevant to an investment in the Notes.

The Notes have not been and will not be registered under the Securities Act, or any state securities laws in the United States or any other jurisdiction, and the Notes may include Bearer Notes that are subject to U.S. tax law requirements. The Notes may be offered and sold (i) in the United States only to QIBs or to "accredited investors" (as defined in Rule 501(a)(1), (2), (3) or (7) under the Securities Act) ("Institutional Accredited Investors"), in each case in transactions exempt from registration under the Securities Act and/or (ii) outside the United States to non-U.S. persons in offshore transactions in reliance on Regulation S. In addition, subject to certain exceptions, Bearer Notes may not be offered, sold or delivered within the United States or to, or for the account or benefit of, United States persons (as defined in the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code")). See "Transfer Restrictions" in the Original Offering Memorandum. The Notes may not be offered or sold in Indonesia or to Indonesian citizens, wherever they are domiciled, or to Indonesian residents, in a manner which constitutes a public offering under Law Number 8 of 1995 on Capital Markets and its implementing regulations.

Arrangers & Dealers

Citigroup **Crédit Agricole CIB** **HSBC** **Mandiri Securities** **Mizuho Securities**

The date of this Supplemental Offering Memorandum is January 13, 2020

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NOTICE TO INVESTORS

This Supplemental Offering Memorandum is to be read in conjunction with the Original Offering Memorandum and all documents which are deemed to be incorporated herein by reference (see "Documents Incorporated by Reference" in the Original Offering Memorandum).

No action has been or will be taken to permit a public offering of any Notes in any jurisdiction where action would be required for that purpose. No Notes may be offered or sold, directly or indirectly, and the Offering Memorandum may not be distributed in any jurisdiction, except in accordance with the legal requirements applicable in such jurisdiction.

If a jurisdiction requires that the offering be made by a licensed broker or dealer and the Dealers or any affiliate of the Dealers is a licensed broker or dealer in that jurisdiction, the offering shall be deemed to be made by that Dealer or its affiliate on behalf of the Issuer in such jurisdiction.

Neither the Offering Memorandum nor any other information supplied in connection with the Program or the Notes constitutes an offer of, or an invitation by or on behalf of our Company, Citigroup Global Markets Inc., Crédit Agricole Corporate and Investment Bank, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd., and Mizuho Securities Asia Limited, as the arrangers of this Program (the "Arrangers"), any of the Dealers, or The Bank of New York Mellon, as trustee (the "Trustee") to subscribe for or purchase, any Notes. Subject as provided in the applicable Pricing Supplement, the only persons authorized to use the Offering Memorandum in connection with an offer of Notes are the persons named in the applicable Pricing Supplement as the Relevant Dealer or any other persons named in the section "Non-exempt Offer" of the Pricing Supplement (if any), as the case may be.

No person has been authorized to give any information or to make any representation other than those contained in the Offering Memorandum, and any information or representation not contained in the Offering Memorandum must not be relied upon as having been authorized by us, the Arrangers, any of the Dealers, the Trustee, the Paying Agent or the Registrar (each as defined herein) or any other person. Neither the delivery of the Offering Memorandum nor any sale of any Notes in connection therewith shall, under any circumstances, constitute a representation or create any implication that the information contained herein is correct as of any time subsequent to the date hereof or that there has been no change in the affairs of any party mentioned herein since that date.

No representation, warranty or undertaking, express or implied, is made by any of the Arrangers, any of the Dealers, or the Trustee, and no responsibility or liability is accepted by any thereof to the accuracy, adequacy, reasonableness or completeness of the information contained in the Offering Memorandum or any other information provided by us in connection with the Notes, their distribution or their future performance. To the fullest extent permitted by law, none of the Dealers or the Arrangers accept any responsibility for the contents of the Offering Memorandum or for any other statement, made or purported to be made by the Arrangers or a Dealer or on any of their behalf in connection with the Issuer or the issue and offering of the Notes. Each Arranger and each Dealer accordingly disclaims all and any liability whether arising in tort or contract or otherwise (save as referred to above) which it might otherwise have in respect of the Offering Memorandum or any such statement.

Neither the Offering Memorandum nor any other information supplied in connection with the Program or the Notes should be considered as a recommendation by us, the Arrangers, any of the Dealers or the Trustee that any recipient of the Offering Memorandum should purchase any of the Notes. Each investor contemplating purchasing any Notes should make its own independent investigation of our business, financial condition and affairs, and its own appraisal of our creditworthiness.

The Notes have not been approved or disapproved by the United States Securities and Exchange Commission (the "SEC"), any state securities commission in the United States or any other U.S. regulatory authority, nor have any of the foregoing authorities passed upon or endorsed the merits of the offering of the Notes or the accuracy or adequacy of the Offering Memorandum. Any representation to the contrary is a criminal offense in the United States.

In connection with the issue of Notes in any Series or Tranche under the Program, the Relevant Dealer or Relevant Dealers (if any) names as the stabilizing manager(s) (the "Stabilizing Manager(s)") in the applicable Pricing Supplement, or any person acting for the Stabilizing Manager(s), may purchase and sell such Notes in the open market. These transactions may, to the extent permitted by applicable laws and regulations, include short sales, stabilizing transactions and purchases to cover positions created by short sales. These activities may stabilize, maintain or otherwise affect the market price of such Notes. As a result, the price of such Notes may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued at any time and must in any event be brought to an end after a limited time. There is no obligation on the Stabilizing Manager(s) or any of the Relevant Dealers to carry out such activities. These activities will be undertaken solely for the account of Stabilizing Manager(s) and/or the Relevant Dealers and not for or on our behalf.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED KINGDOM

The Notes may not be offered or sold to any person in the United Kingdom, other than to persons whose ordinary activities involve them acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses or otherwise in circumstances which have not resulted and will not result in an offer to the public in the United Kingdom.

NOTICE TO PROSPECTIVE INVESTORS IN CANADA

The Notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the Notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws. Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor. Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

MIFID II PRODUCT GOVERNANCE/TARGET MARKET

The Pricing Supplement may include a legend entitled "MiFID II Product Governance" which will outline the target market assessment in respect of the Notes and which channels for distribution of the Notes are appropriate. Any person subsequently offering, selling or recommending the Notes (a "distributor") should take into consideration the target market assessment; however, a distributor subject to Directive 2014/65/EU (as amended, "MiFID II") is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the target market assessment) and determining appropriate distribution channels.

A determination will be made in relation to each issue about whether, for the purpose of the MiFID Product Governance rules under EU Delegated Directive 2017/593 (the "MiFID Product Governance Rules"), any Dealer subscribing for any Notes is a manufacturer in respect of such Notes, but otherwise, unless so determined, neither the Arrangers nor the Dealers nor any of their respective affiliates will be a manufacturer for the purpose of the MiFID Product Governance Rules.

PROHIBITION OF SALES TO EEA RETAIL INVESTORS

If the Pricing Supplement in respect of any Notes includes a legend entitled "Prohibition of Sales to EEA Retail Investors," the Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the European Economic Area ("EEA"). For these purposes, a retail investor in the EEA means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of MiFID II; (ii) a customer within the meaning of Directive (EU) 2016/97 (as amended, the "Insurance Distribution Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; and (iii) not a qualified investor as defined in Regulation (EU) 2017/1129 (the "Prospectus Regulation"). Consequently, no key information document required by Regulation (EU) No 1286/2014 (as amended, the "PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.

NOTIFICATION UNDER SECTION 309B(1)(C) OF THE SECURITIES AND FUTURES ACT (CHAPTER 289) OF SINGAPORE

Unless otherwise stated in the Pricing Supplement in respect of any Notes, all Notes issued or to be issued under the Program shall be prescribed capital market products (as defined in the Securities and Futures (Capital Markets Products) Regulations 2018) and Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

NOTICE TO PROSPECTIVE INDONESIAN INVESTORS

The Notes have not been offered or sold and will not be offered or sold in the Republic of Indonesia or to any Indonesian nationals, corporations or residents, including by way of invitation, offering or advertisement, and the Offering Memorandum and any other offering material relating to

the Notes has not been distributed, and will not be distributed, in the Republic of Indonesia or to any Indonesian nationals, corporations or residents in a manner which would constitute a public offering in the Republic of Indonesia under Law Number 8 of 1995 on Capital Markets. The Indonesian Financial Service Authority (*Otoritas Jasa Keuangan* or the "OJK") has not reviewed or declared its approval or disapproval of the issue of the Notes, nor has it made any determination as to the accuracy or adequacy of the Offering Memorandum. Any statement to the contrary is a violation of Indonesian law.

ENFORCEABILITY OF FOREIGN JUDGMENTS IN INDONESIA

The Issuer is a state-owned limited liability company established and existing in Indonesia. All of our commissioners, directors and executive officers reside in Indonesia. Substantially all of the assets of the Issuer and these other persons are located outside the United States. As a result, it may be difficult for investors to effect service of process upon such persons within the United States, or to enforce against us in court, judgments obtained in U.S. courts, including judgments predicated upon the civil liability provisions of the federal securities laws of the United States.

We have been advised by our Indonesian legal advisor, Ali Budiardjo, Nugroho, Reksodiputro, that judgments of courts outside Indonesia are not enforceable in Indonesian courts. A foreign court judgment could be offered and accepted into evidence in a proceeding on the underlying claim in an Indonesian court and may be given such evidentiary weight as the Indonesian court may deem appropriate in its sole discretion. A claimant may be required to pursue claims in Indonesian courts on the basis of Indonesian law. A purchaser of the Notes may not be able to enforce judgments against us obtained in the United States based upon certain of the civil liability provisions of the securities laws of the United States or any states thereof in Indonesian courts, and Indonesian courts may not enter judgments in original actions brought in Indonesian courts based solely upon the civil liability provision of the securities laws of the United States or any state thereof. Re-examination of the underlying claim would be required before the Indonesian court. There can be no assurance that the claims or remedies available under Indonesian law will be the same, or as extensive as those available in other jurisdictions. For more details, see "Risk Factors — Risks Relating to Indonesia — It may not be possible for investors to effect service of process or to enforce certain judgments on the Issuer or its management" and "Risk Factors — Risks Relating to Indonesia — Holders of the Notes will be exposed to a legal system subject to considerable discretion and uncertainty and may have difficulty pursuing claims under the Notes."

INDONESIAN REGULATION OF OFFSHORE BORROWINGS

Pursuant to Presidential Decree No. 39 of 1991, we are required to obtain prior approval from the Offshore Commercial Borrowing Team (the "PKLN Team") to receive offshore borrowings and must submit periodic reports to the PKLN Team. However, the decree does not stipulate either the time frame or the format and the content of the periodic report that must be submitted. Under Presidential Decree No. 59 of 1972, dated October 12, 1972, as partly revoked by the Presidential Decree No. 15 of 1991 on Receipt of Offshore Loans and Issuance of Bank Guarantees for the Acceptance of Offshores Loans by State-Owned Banks and Regional Development Banks Stipulated as Foreign Exchange Banks ("PD 59/1972"), we are required to obtain approval from the Minister of Finance of Indonesia and report the particulars of our offshore commercial borrowings to the Minister of Finance of Indonesia and Bank Indonesia, on the acceptance, implementation, and repayment of principal and interest. In practice, this approval from the Minister of Finance under PD 59/1972 is considered to have been obtained when approval from the PKLN Team is received because the Minister of Finance of Indonesia is a member of the PKLN Team. Minister of Finance Decree No. KEP-261/MK/IV/5/1973 dated May 3,

1973, as amended by the Minister of Finance Decree No. 417/KMK.013/1989 dated May 1, 1989 and partly revoked by the Minister of Finance Decree No. 279/KMK.01/1991 dated March 18, 1991, as the implementing regulation of this PD 59/1972, further sets forth the requirement to submit periodic reports to the Minister of Finance of Indonesia and Bank Indonesia on the effective date of the contract and each subsequent three-month period.

See "Indonesian Regulatory Framework — Indonesian Regulation of Offshore Borrowings" for information on certain regulations in Indonesia which apply to our offshore borrowings.

CERTAIN DEFINED TERMS AND CONVENTIONS

As used in this Offering Memorandum, unless the context otherwise requires, the terms "we," "us," "our," "our Company" and "Pertamina" refer to PT Pertamina (Persero) and its consolidated subsidiaries and the term the "Issuer" refers to PT Pertamina (Persero) on a standalone basis.

In the Offering Memorandum, references to "US$," "$" and "U.S. dollars" are to United States dollars, the legal currency of the United States, references to "Rupiah" and "Rp." are to the legal currency of Indonesia, references to "€" and "Euro" are to the legal currency of certain member states of the European Union and references to "¥" and "Japanese Yen" are to the legal currency of Japan . Unless otherwise specified or the context otherwise requires, all references to "Indonesia" are references to the Republic of Indonesia. All references to the "Government" herein are references to the Government of the Republic of Indonesia. All references to "United States" or "U.S." herein are references to the United States of America. Certain terms used herein are defined in the "Glossary" contained in the Original Offering Memorandum.

Unless otherwise expressly stated, all operational data of our Company contained in this Supplemental Offering Memorandum is given as of September 30, 2019.

All references herein to the "Oil and Gas Law of 2001" are references to the oil and gas law enacted on November 23, 2001 as partially annulled by the Constitutional Court of the Republic of Indonesia on December 15, 2004 and November 13, 2012. References to "SKK MIGAS" are references to the Special Working Unit for the Implementation of Upstream Natural Oil and Gas Business Activity (Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi) and references to "BPMIGAS" are references to the predecessor to SKK MIGAS, the Executive Agency for Upstream Oil and Gas Activities (Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi), a non-profit Government-owned legal entity which was dissolved pursuant to the decision of the Constitutional Court of the Republic of Indonesia Decision No. 36/PUU-X/2012 dated November 13, 2012. References to "BPH MIGAS" are references to the Oil and Gas Downstream Regulatory Body (Badan Pengatur Hilir Minyak dan Gas Bumi), an independent governmental agency. For more information see "Indonesian Regulatory Framework."

See "Business — Pertamina Upstream Business — Reserves" in the Original Offering Memorandum for definitions of net reserves, proved reserves, proved plus probable reserves, proved developed reserves and proved undeveloped reserves.

See "Business — Pertamina Upstream Business — Production" in the Original Offering Memorandum for a definition of production and net production in respect of our upstream business. See "Indonesian Regulatory Framework" for a description of the production sharing arrangements between us and the Government.

Our working interest is given after taking into account any dilution due to ownership through subsidiaries which are less than wholly owned, directly or indirectly, by us.

In respect of our downstream businesses, unless otherwise specified, all references in the Offering Memorandum to "production capacity" of a facility means the maximum amount that can, or is expected to be able to, be produced by such facility. No representation is made that the amount of production (if any) from such facility is or will or is expected to be equal to the production capacity of a facility and production capacity should not be treated as indicative of future levels of production.

Unless otherwise indicated or in the case of oil prices, references to "crude oil" or "oil" include condensate. Natural gas equivalents and crude oil equivalents are determined using the ratio of 1 mmcf of natural gas to 0.1726 mboe of oil equivalent, except in "Industry Overview" of the Original Offering Memorandum, where natural gas equivalents and crude oil equivalents are determined using the ratio of 1 mmcf of natural gas to 0.176 mboe of oil equivalent.

INDUSTRY AND MARKET DATA

The Offering Memorandum includes certain industry and market data (including forecasts and other forward-looking information) obtained from, among others, the Central Bureau of Statistics (Badan Pusat Statistik, formerly known as Biro Pusat Statistik), the World Bank and reports of other governmental agencies, industry publications and surveys, and internal company surveys. Such industry publications and surveys and forecasts generally state that the data contained therein has been obtained from sources believed to be reliable, but we cannot assure you that such data is complete or accurate, nor has such data been independently verified, and neither we, nor the Arrangers or any Dealer make any representation as to the accuracy or completeness of such data or any assumptions relied upon therein.

The Offering Memorandum, including the section titled "Industry Overview" in the Original Offering Memorandum, also contains certain industry and market data derived from a report commissioned by us and prepared by our energy industry consultant Wood Mackenzie Asia Pacific Pte Ltd ("Wood Mackenzie") titled "*Indonesia Oil and Gas Industry Report (Final): July* 2019" (the "Wood Mackenzie Report"). The information contained in the Wood Mackenzie Report is as of March 20, 2019 unless otherwise stated therein. Other than information about Pertamina that was provided by us to Wood MacKenzie, the industry and market data in the Wood Mackenzie Report has not been independently verified by us, the Arrangers or the Dealers, and neither we, except with respect to information which we have provided, nor the Arrangers or any Dealer make any representation as to the accuracy or completeness of such data or any assumptions relied upon therein.

The Wood Mackenzie Report contains certain data produced by Wood Mackenzie about Indonesia's and our oil and gas reserves. Wood MacKenzie's categorization of oil and gas reserves as "commercial reserves" and "technical reserves" is not part of a system of oil and gas reporting definitions that is recognized by a professional standards-setting body or a securities regulator. Pertamina reports its oil and gas reserves under its oil and gas resource management system, which is consistent with the Petroleum Resource Management System ("PRMS") approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers. See also "Presentation of Financial and Other Data — Oil and Gas Reserves" and "Business — Pertamina Upstream Business — Oil and Gas Reserves." Investors should carefully consider the differences between the categories Wood MacKenzie employs and the industry-standard categories that Pertamina uses to calculate its oil and gas reserves and resources. Investors should not assume that quantities of oil and gas that Wood Mackenzie describes as reserves or resources would be categorized as reserves or resources under the PRMS.

Financial data with respect to Indonesia provided in the Offering Memorandum may be subsequently revised in accordance with Indonesia's ongoing maintenance of its economic data, and such revised data will not be distributed by us to any holder of the Notes.

PRESENTATION OF FINANCIAL AND OTHER DATA

Exchange Rate Information

Solely for convenience, the Supplemental Offering Memorandum contains translations of certain Rupiah amounts into U.S. dollars at the exchange rate of Rp. 14,195 = US$1.00, which was the middle exchange rate according to Bloomberg Finance LP as of September 30, 2019 and translations of certain Japanese Yen amounts into U.S. dollars at the exchange rate of ¥100 = US$0.92 which was the middle exchange rate according to Bloomberg Finance LP as of September 30, 2019 and certain Euro amounts into U.S. dollars at the exchange rate of €0.91 = US$1.00, which was the middle exchange rate according to Bloomberg Finance LP as of September 30, 2019. These translations should not be construed as representations that the Rupiah amounts represent such U.S. dollar amounts or could be, or could have been, converted into U.S. dollars at the rates indicated or at all. See "Exchange Controls" in the Original Offering Memorandum for further information regarding the rates of exchange between the Rupiah and the U.S. dollar.

Financial Information

Our consolidated financial statements and, unless otherwise indicated, financial information in the Offering Memorandum has been prepared in accordance with Indonesian Financial Accounting Standards ("IFAS"), which differ in certain respects from generally accepted accounting principles in the United States ("U.S. GAAP"). For a summary of certain differences between IFAS and U.S. GAAP, see "Summary of Certain Significant Differences Between IFAS and U.S. GAAP" in the Original Offering Memorandum. Except as otherwise indicated or the context otherwise requires, financial information in the Offering Memorandum is presented on a consolidated basis.

Our consolidated financial statements as of December 31, 2018, 2017 and 2016 and for the years then ended included in this Supplemental Offering Memorandum have been audited by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants (the "IICPA"), as stated in their audit report appearing in this Supplemental Offering Memorandum.

Our unaudited interim consolidated financial statements as of September 30, 2019 and for the nine-month periods ended September 30, 2019 and 2018 have been reviewed by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with SRE 2410, established by the IICPA, as stated in their review report appearing elsewhere in this Supplemental Offering Memorandum (presented combined with the audit report mentioned above). A review conducted in accordance with SRE 2410 established by the IICPA is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the IICPA, and as stated in their review report appearing in this Supplemental Offering Memorandum (presented combined with the audit report mentioned above), KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountant, did not audit and do not express any opinion on such unaudited interim consolidated financial statements included elsewhere in this Supplemental Offering Memorandum.

PGN

Certain operational data of PT Perusahaan Gas Negara Tbk ("PGN") and its subsidiaries (including Pertagas) has been included in the Offering Memorandum. Unless otherwise stated, the operational data of Pertamina in the Offering Memorandum (including relating to our natural gas transmission and distribution, LNG production, upstream and downstream oil and gas businesses and strategies, proved plus probable oil and gas reserves, exploratory and development wells, oil and gas fields/blocks and upstream oil and gas production and distribution) excludes the operational data of PGN and its subsidiaries. For more information, see "Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements" in the Original Offering Memorandum.

In the Offering Memorandum, references to our "net income" are to our "profit for the period/year after the effect of merging entity's income adjustment attributable to owners of the parent entity."

Rounding

Rounding adjustments have been made in calculating some of the financial information and reserves and production information included in the Offering Memorandum. As a result, numerical figures shown as totals in some tables may not be exact arithmetic aggregations of the figures that precede them.

Non-GAAP Financial Measures

The Offering Memorandum includes certain non-GAAP financial measures for Pertamina, including Adjusted EBITDA and dividend payout ratio. Adjusted EBITDA and the related ratios presented in the Offering Memorandum and dividend payout ratio are supplemental measures of our performance and liquidity that are not required by, or presented in accordance with, IFAS or U.S. GAAP. Adjusted EBITDA is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to profit for the period/year after the effect of merging entity's income adjustment attributable to owners of the parent entity (which is our net income), operating income or any other performance measures derived in accordance with IFAS or U.S. GAAP or as an alternative to cash flow from operating activities or as a measure of liquidity. In addition, Adjusted EBITDA is not a standardized term, hence a direct comparison between companies using such a term may not be possible.

We calculate Adjusted EBITDA in accordance with *Kementerian Badan Usaha Milik Negara* (Indonesia's Ministry of State Owned Enterprises), or Decree of the Minister of State-Owned Enterprises Number: Kep-100/MBU/2002 concerning Assessment of the Health Level of State-Owned Enterprises (*Keputusan Menteri Badan Usaha Milik Negara Nomor: Kep-100/MBU/2002 Tentang Penilaian Tingkat Kesehatan Badan Usaha Milik Negara*) ("**BUMN Regulation KEPMEN 100**"), which requires adjustment for all finance costs and does not take into account the effects of merging entity's income adjustment, which arise in connection with acquisitions during the year or period. In comparison, our calculations of EBITDA in the past adjusted for interest expense and not accretion expenses related to decommissioning and site restoration or other finance costs and took into account the effects of merging entity's income adjustment. Adjusted EBITDA and the related ratios presented in the Offering Memorandum are therefore not comparable to our previously disclosed EBITDA and related ratios.

See "Summary Consolidated Financial and Other Data" in this Supplemental Offering Memorandum for more information, including details of our calculation of Adjusted EBITDA and a reconciliation of our net income under IFAS to our definition of Adjusted EBITDA.

Oil and Gas Reserves

Except where attributed to Wood Mackenzie, the information on our historical oil and gas reserves in the Offering Memorandum is based on our estimated "net reserves" and, as such, represents our aggregate share of the estimated crude oil and/or natural gas reserves in all blocks or fields or specified areas, attributable to our working interest in such areas, before deducting the share payable to the Government as owner of the reserves pursuant to the terms of the relevant production sharing arrangement, the cost recovery portion and any applicable taxes.

These estimates have been prepared based on our oil and gas and geothermal resource management system, which contains procedures for classifying and estimating reserves. Until December 31, 2018, the procedures for our oil and gas resource management system and the classifications of our reserves were consistent with PRMS approved in March 2007 ("PRMS 2007") by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. PRMS 2007 was generally considered the oil and gas industry standard for reserve reporting until it was superseded by a new PRMS released in June 2018 ("PRMS 2018").

Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Supplemental Offering Memorandum, estimates of our oil and gas reserves as of September 30, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

Estimates of reserves are largely dependent on the interpretation of data obtained from drilling, testing and production and may prove to be incorrect over time. Estimates of proved reserves that may be developed and produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs, rather than upon actual production history. Subsequent evaluation of the same reservoirs based upon production history may result in revisions to the estimated proved or proved plus probable reserves. An estimate of reserves is based in part on a field's long-term development plan, and reserves are classified or adjusted and re-classified as contingent where a long-term development plan has not been finalized or is not up-to-date. The estimation of reserves involves a significant degree of judgment by our management, engineers and technical personnel. Reserves estimates are subject to various uncertainties, including those relating to the physical characteristics of oil and gas fields, as well as changes in oil prices. These uncertainties are difficult to estimate and, as a result, actual production may be materially different from current estimates of reserves. No assurance can be given that the reserves presented in this Supplemental Offering Memorandum will be recovered at the levels presented. See "Risk Factors — Risks Relating to Our Upstream Operations — Our crude oil, natural gas and geothermal reserve estimates are uncertain and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these resources" in the Original Offering Memorandum.

See "Business — Pertamina Upstream Business — Reserves" in the Original Offering Memorandum for definitions relating to our reserves and details of our reserve estimation methodology and techniques.

Cautionary Note to United States Investors Concerning Estimates of Measured, Indicated and Inferred Resources for Oil and Gas Programs

There are principal differences between the reporting regimes under the PRMS 2007, PRMS 2018 and in the United States under the requirements as adopted by the SEC in its Industry Guide 4 — Prospectus Relating to Interests in Oil and Gas Programs and Subpart 1200 of Regulation S-K (together "Industry Guide 4").

UNITED STATES INVESTORS ARE ADVISED THAT THE REPORTING REGIMES USED IN THE OFFERING MEMORANDUM ARE ACCORDINGLY NOT COMPLIANT WITH INDUSTRY GUIDE 4.

AVAILABLE INFORMATION

In the event that Notes are offered and sold in reliance on Rule 144A, we shall, for so long as any of the Notes are "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act, during any period in which we are not subject to Section 13 or 15(d) of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"), or exempt from reporting pursuant to Rule 12g3-2(b) under the Exchange Act, make available to any qualified institutional buyer (as defined in Rule 144A) who is a holder of such restricted securities and any prospective purchaser of such restricted securities who is a qualified institutional buyer (as so defined) designated by such holder, upon the request of such holder or prospective purchasers, the information concerning us required to be provided to such holder or prospective purchaser by Rule 144A(d)(4) under the Securities Act.

FORWARD-LOOKING STATEMENTS

The Offering Memorandum includes, and any amendment or supplement, may include forward-looking statements. All statements other than statements of historical facts included in the Offering Memorandum and any amendment or supplement regarding, among other things, our future financial position and results of operations, business, strategy, plans, developments and prospects, the condition and prospects of the oil, gas and geothermal industries, and Indonesia's economy, fiscal condition, debt or prospects may constitute forward-looking statements. Forward-looking statements can generally be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "continue" or similar terminology. Specifically, statements under the captions "Summary," "Industry Overview," "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Business," "Indonesian Regulatory Framework" and "Relationship with the Government" in the Original Offering Memorandum relating to the following matters may include forward-looking statements relating to:

- the expected results of our exploration, development, production, refining and distribution activities and related capital expenditures and investments;
- our oil, gas and geothermal reserve estimates, the classification of our oil, gas and geothermal reserves and our ability to extract oil, gas and geothermal energy;
- our strategic, business and financial plans and objectives, including budgeted and future capital expenditures, acquisitions and investments, (i) in respect of future oil, gas and

geothermal exploration, development and production; (ii) in respect of the future construction, expansion, production capacity and utilization of our refining and other facilities; and (iii) in respect of the future construction, expansion, acquisition or operation of our distribution, trading and transportation networks;

- the anticipated demand and selling prices for crude oil, natural gas, geothermal energy, refined petroleum and petrochemical products, drilling activities and power;

- sales to existing and potential customers, whether under sales contract or not, and generation of future receivables;

- our ability to be and remain competitive in each of our main business segments;

- our financial position, business strategy and budget, including projected financial and operating data;

- existing and future regulatory requirements applicable to us and our businesses; and

- existing and future obligations in respect of environmental compliance and remediation.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various important factors, including those set out in the Offering Memorandum. Factors that could cause actual results to differ include, but are not limited to, the following:

- changes and volatility in market prices of or demand for key commodities produced or consumed by us, including crude oil and natural gas, as a result of competitive actions, economic factors such as inflation or exchange rate fluctuations, or otherwise;

- changes in our relationship with the Government, SKK MIGAS, BPH MIGAS and other government authorities in Indonesia and other countries in which we operate, our joint venture partners, our shareholder, our co-investors and other counterparties, in Indonesia and other countries in which we operate;

- whether we have or are able to obtain sufficient working capital to meet our cash and operational requirements, including through external financing;

- operational risks and hazards, such as accidents, natural disasters and other catastrophes;

- increases or other changes in regulatory burdens and obligations in Indonesia and other countries, including our public service obligation ("PSO"), dividend obligations, and environmental regulations and compliance costs;

- our ability to implement our growth strategy and development plans, including our ability to consummate future acquisitions, joint ventures or investments;

- economic, social and political conditions in Indonesia and other countries in which we operate;

- changes in terms and conditions of the agreements under which we operate our businesses and the ability of third parties to perform in accordance with contractual terms and specifications;

- changes in import or export controls, duties, levies or taxes, either in international markets or in Indonesia;

- changes in laws and regulations and their interpretation, applicable taxes and tax rates, accounting standards or practices, and reserve reporting guidelines; and

- our ability to manage the risks described above and in the section captioned "Risk Factors" in the Original Offering Memorandum.

Although we believe that the expectations of our management as reflected by such forward-looking statements are reasonable based on information currently available to us, no assurances can be given that such expectations will prove to be correct.

In addition, our management's expectations with respect to our exploration, production, development, refining and distribution activities are subject to risks arising from the inherent difficulty of predicting the presence, yield or quality of oil, gas and geothermal reserves, as well as unknown or unforeseen difficulties in extracting, transporting, refining or processing any oil, gas or geothermal energy found, or doing so on a commercial basis.

Our ability to maintain and grow our revenues, net income and cash flows depends upon continued capital expenditure. In addition, our capital expenditure and investment plans are subject to a number of risks, contingencies and other factors, such as oil and gas prices, market demand, geological factors, acquisition opportunities and the success of our exploration program, some of which are beyond our control. Our ability to obtain adequate financing to satisfy our capital expenditure and investment budget and debt service requirements may be limited by our financial condition, results of operations, legal and regulatory issues and the liquidity of international and domestic financial markets. We may make additional capital expenditures and investments as opportunities or needs arise, and may increase, reduce or suspend our planned capital expenditures or investments or change the timing and use of its capital expenditures from what is currently planned in response to market conditions, drilling results, production trends or for other reasons.

Should one or more of these uncertainties or risks, among others, materialize, our actual results may vary materially from those estimated, anticipated or projected. Specifically, but without limitation, capital costs could increase, projects could be delayed, and anticipated improvements in production, capacity or performance might not be fully realized or realized at all.

Accordingly, prospective purchasers are cautioned not to place undue reliance on forward-looking statements. In any event, these statements speak only as of their dates, and we undertake no obligation to update or revise any of them, whether as a result of new information, future events or otherwise.

OVERVIEW OF THE PROGRAM

The following overview does not purport to be complete and is taken from and is qualified in its entirety by, the remainder of the Offering Memorandum and, in relation to the terms and conditions of any particular Tranche of Notes, the applicable Pricing Supplement. Words and expressions defined in "Forms of the Notes" and "Description of the Notes" in the Original Offering Memorandum shall have the same meanings in this summary.

Under the Program, the Company may, from time to time, issue Notes denominated in U.S. dollars, Euros or in any other currency, subject to the terms more fully set forth herein. A summary of the terms and conditions of the Program and the Notes appears below. The applicable terms of any Notes will be agreed upon by and between the Company and the relevant Dealer(s) prior to the issue of the Notes and will be set forth in the Description of the Notes endorsed on, or incorporated by reference into, the Notes, as modified and supplemented by the applicable Pricing Supplement attached to, or endorsed on, such Notes, as more fully described under "Forms of Notes" in the Original Offering Memorandum.

Summary of the Program and Description of the Notes

Company:	PT Pertamina (Persero)
Arrangers:	Citigroup Global Markets Inc., Crédit Agricole Corporate and Investment Bank, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd., and Mizuho Securities Asia Limited.
Dealers:	Citigroup Global Markets Inc., Crédit Agricole Corporate and Investment Bank, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd., and Mizuho Securities Asia Limited. The Company may issue Notes to persons other than Dealers and may terminate the appointment of any Dealer or appoint new dealers for a particular Series of Notes or for the Program.
Trustee:	The Bank of New York Mellon
Paying Agent(s):	The Bank of New York Mellon, The Bank of New York Mellon, London Branch
Registrar:	The Bank of New York Mellon
Euro Registrar:	The Bank of New York Mellon SA/NV, Luxembourg Branch
Transfer Agent:	The Bank of New York Mellon
Description:	Global Medium Term Note Program

Program Size:	Up to US$10,000,000,000 (or its equivalent in any other currency (the "Program Limit") in aggregate nominal amount of Notes outstanding at any one time). The Company may increase the amount of the Program Limit in accordance with the terms of the Program Agreement.
Method of Issue:	The Notes will be issued on a syndicated or non-syndicated basis. The Notes will be issued in series (each, a "Series") having one or more issue dates and on terms otherwise identical (or identical other than in respect of the first payment of interest and their Issue Price), the Notes of each Series being intended to be fungible with all other Notes of that Series. Each Series may be issued in tranches (each, a "Tranche") on the same or different issue dates. The specific terms of each Tranche (which will be completed, where necessary, with the relevant terms and conditions and, save in respect of the issue date, issue price, first payment of interest and nominal amount of the Tranche, will be identical to the terms of other Tranches of the same Series) will be specified in the pricing supplement (the "Pricing Supplement").
Issue Price:	Notes may be issued at their nominal amount or at a discount or premium to their nominal amount. Partly Paid Notes may be issued, the issue price of which will be payable in two or more installments.
Form of Notes:	The Notes may be issued in bearer or registered form, as specified in the applicable Pricing Supplement. Certificates representing the Notes that are registered in the name of a nominee for one or more clearing systems are referred to as "Global Securities." Each Series of Bearer Notes will initially be represented by a Temporary Global Note or a Permanent Global Note which, in each case, will be deposited on the Issue Date with a common depositary for Euroclear, Clearstream or any other agreed clearance system compatible with Euroclear and Clearstream. Interests in a Temporary Global Note will be exchangeable, from the 40th day following the issue date, for either interests in a Permanent Global Note or Definitive Bearer Notes (as indicated in the applicable Pricing Supplement) and in the case of Notes to which the D Rules (as defined below) apply, upon certification of non-U.S. beneficial ownership as required by United States Treasury regulations ("U.S. Treasury Regulations"). Interests in a Permanent Global Note will be exchangeable, unless otherwise specified in the applicable Pricing Supplement, only in the limited circumstances described therein, in whole but not in part for Definitive Bearer Notes, upon written notice to the Trustee. Any interest in a Temporary Global Note or a Permanent Global Note will be transferable only in accordance with the rules and procedures for the time being of Euroclear, Clearstream and/or any other agreed clearance system, as appropriate. Each Series of Registered Notes, which are sold outside the United States in reliance on Regulation S, will, unless otherwise specified in the applicable Pricing Supplement, be represented by an Unrestricted

	Global Security, which will be deposited on or about its Issue Date with a common depositary for, and registered in the name of a nominee, of Euroclear and Clearstream. Unrestricted Global Securities will be exchangeable for Certificated Securities only in the limited circumstances more fully described herein. Any Series of Registered Notes sold in private transactions to QIBs and subject to the transfer restrictions described in "Transfer Restrictions" in the Original Offering Memorandum will, unless otherwise specified in the applicable Pricing Supplement, be represented by a Restricted Global Security, which will be deposited on or about its Issue Date with a custodian for, and registered in the name of a nominee of, DTC. Persons holding beneficial interests in Registered Global Securities will be entitled or required, as the case may be, under the circumstances described in the Indenture, to receive physical delivery of Certificated Securities. Registered Notes initially offered and sold in the United States to Institutional Accredited Investors pursuant to Section 4(a)(2) of the Securities Act or in a transaction otherwise exempt from registration under the Securities Act and subject to the transfer restrictions described in "Transfer Restrictions" in the Original Offering Memorandum will be issued only in definitive registered form and will not be represented by a Global Security. Bearer Notes will not be exchangeable for Registered Notes, and Registered Notes will not be exchangeable for Bearer Notes.
Clearing Systems:	DTC, Clearstream, Euroclear and, in relation to any Tranche, such other clearing system as may be agreed between the Company, the Trustee and the relevant Dealer. See "Global Clearance and Settlement Systems" in the Original Offering Memorandum.
Currencies:	Subject to compliance with all relevant laws, regulations and directives, Notes may be issued in any currency agreed between the Company and the relevant Dealer(s).
Maturities:	Subject to compliance with all relevant laws, regulations and directives, any maturity.
Specified Denomination:	Notes will be in such denominations as may be specified in the relevant Pricing Supplement save that (i) in the case of any Notes which are to be admitted to trading on a regulated market within the European Economic Area or offered to the public in an EEA State in circumstances which require the publication of a prospectus under the Prospectus Regulation, the minimum specified denomination shall be US$200,000 (or its equivalent in any other currency as of the date of issue of the Notes); and (ii) unless otherwise permitted by then current laws and regulations, Notes (including Notes denominated in sterling) which have a maturity of less than one year will have a minimum denomination of £100,000 (or its equivalent in other currencies).

Fixed Rate Notes:	Fixed interest will be payable in arrears on the date or dates in each year specified in the relevant Pricing Supplement.
Floating Rate Notes:	Floating Rate Notes will bear interest determined separately for each Series as set out in the Description of the Notes and the relevant Pricing Supplement.
Zero Coupon Notes:	Zero Coupon Notes may be issued at their nominal amount or at a discount to it and will not bear interest.
Dual Currency Notes:	Payments in respect of Dual Currency Notes will be made in such currencies, and based on such rates of exchange as may be specified in the relevant Pricing Supplement.
Index-Linked Notes:	Payments of principal in respect of Index-Linked Redemption Notes or of interest in respect of Index-Linked Interest Notes will be calculated by reference to such index and/or formula as may be specified in the relevant Pricing Supplement.
Interest Periods and Interest Rates:	The length of the interest periods for the Notes and the applicable interest rate or its method of calculation may differ from time to time or be constant for any Series. Notes may have a maximum interest rate, a minimum interest rate, or both. All such information will be set out in the relevant Pricing Supplement.
Redemption:	The relevant Pricing Supplement will specify the basis for calculating the redemption amounts payable. Unless permitted by then current laws and regulations, Notes (including Notes denominated in sterling) which have a maturity of less than one year must have a minimum redemption amount of £100,000 (or its equivalent in other currencies).
Redemption by Installments:	The Pricing Supplement issued in respect of each issue of Notes that are redeemable in two or more installments will set out the dates on which, and the amounts in which, such Notes may be redeemed.
Optional Redemption:	The Pricing Supplement issued in respect of each issue of Notes will state whether such Notes may be redeemed prior to their stated maturity at the option of the Company (either in whole or in part) and/or the Holders, and if so the terms applicable to such redemption.
Redemption upon a Change of Control Triggering Event:	Unless otherwise stated in the relevant Pricing Supplement and unless the Notes are previously redeemed, repurchased and cancelled, the Company will, no later than 30 days following a Change of Control Triggering Event (as defined in the indenture governing the Notes), make an Offer to Purchase (as defined in the Notes of the relevant Series) all outstanding Notes of any Series at a purchase price of 101% of their principal amount, together with accrued and unpaid interest, if any.

Status of Notes:	The Notes will constitute direct, unsubordinated and unsecured obligations of the Company.
Certain Covenants:	Unless otherwise stated in the relevant Pricing Supplement, the Company will agree in the terms and conditions of the Notes of any Series to observe certain covenants, including, among other things, the incurrence of liens, mergers, acquisitions and disposals and certain other covenants. See "Description of the Notes" in the Original Offering Memorandum.
Events of Default:	Certain events will permit acceleration of the principal of the Notes (together with all interest and additional amounts accrued and unpaid thereon). These events include default with respect to the payment of principal of, premium, if any, or interest on, the Notes.
Ratings:	Tranches of Notes will be rated or unrated. Where a Tranche of Notes is to be rated, such rating will be specified in the relevant Pricing Supplement. A rating is not a recommendation to buy, sell or hold securities and may be subject to suspension, reduction or withdrawal at any time by the assigning rating agency.
Withholding Tax:	All payments of principal and interest in respect of the Notes will be made free and clear of withholding taxes unless such withholding is required by law. Indonesia currently applies a withholding tax of 20% to payments of interest on the Notes. In respect of any such withholding required by law, the Company will pay additional amounts that will result in receipt by the holders of the Notes of such amounts as would have been received by them had no such withholding been required, subject to customary exceptions, all as described in "Description of the Notes — Taxation" in the Original Offering Memorandum.
Selling Restrictions:	There are restrictions on the offer, sale and transfer of the Notes in the United States, Hong Kong, Singapore, Japan, Indonesia, Italy, the European Economic Area and Switzerland (including the public offer selling restriction under the Prospectus Regulation and the United Kingdom. See "Plan of Distribution" in the Original Offering Memorandum. Bearer Notes will be issued in compliance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(D) for purposes of Section 4701 of the Internal Revenue Code (the "D Rules") unless (i) the relevant Pricing Supplement states that Bearer Notes are issued in compliance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(C) for purposes of Section 4701 of the Internal Revenue Code (the "C Rules") or (ii) Bearer Notes are issued other than in compliance with the D Rules or the C Rules but in circumstances in which the Notes will not constitute "registration required obligations" for U.S. federal income tax purposes, which circumstances will be referred to in the relevant Pricing Supplement

	as a transaction to which the Tax Equity and Fiscal Responsibility Act of 1982 ("TEFRA") is not applicable.
Use of Proceeds:	We intend to use net proceeds from the issue of each Tranche of Notes to finance capital expenditures and for general corporate purposes or as set forth in the Pricing Supplement applicable to such Notes.
Listing:	Application has been made to the SGX-ST for permission to deal in and for the listing of and quotation of any Notes that may be issued pursuant to the Program and which are agreed at or prior to the time of issue thereof to be so listed on the SGX-ST. There is no assurance that an application to the SGX-ST for the listing of the Notes of any Series will be approved. For so long as any Notes are listed on the SGX-ST and the rules of the SGX-ST so require, such Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in any other currency). The Notes may also be listed on such other or further stock exchange(s) as may be agreed between the Company and the relevant Dealer in relation to each Series. Unlisted Notes may also be issued under the Program. The relevant Pricing Supplement will state whether or not the Notes of a Series will be listed on any exchange(s) and, if so, on which exchange(s) the Notes are to be listed.
Governing Law:	The Notes will be governed by, and construed in accordance with, the laws of the State of New York.

SUPPLEMENTAL RISK FACTORS

The Risk Factor section on page 21 to 65 of the Original Offering Memorandum shall be amended and supplemented, where applicable, with the following information:

Risks Relating to Our Company

Changes to IFAS standards for lease accounting may adversely affect our financial results and position.

The International Accounting Standards Board (IASB) released a new standard (IFRS 16) on lease accounting, which replaced International Accounting Standards (IAS) 17 Leases and which became effective for financial reporting periods beginning on or after January 1, 2019. The corresponding standard we follow is Pernyataan Standar Akuntansi Keuangan ("PSAK 73"), which will become effective for financial reporting periods beginning on or after January 1, 2020. The application of PSAK 73 is expected to have an impact on our financial statements and we are currently evaluating and have not yet determined its impact. For example, the implementation of PSAK 73 may affect leases that are recognized in our financial statements and there might be an impact on our liabilities, depreciation and interest expenses. These and any other changes to the PSAK standards (or International Financial Reporting Standards (IFRS) implemented by corresponding PSAK standards) that may be proposed in the future could have a material adverse effect on our results of operations or financial condition.

Risks Relating to Indonesia

An Indonesian law requiring agreements involving Indonesian parties, which includes the Indenture and certain other documents entered into in connection with the Program or any issue of Notes thereunder, to be written in the Indonesian language may raise issues as to the enforceability of agreements.

Pursuant to Law No. 24 of 2009 regarding Flag, Language, Coat of Arms, and National Anthem ("Law No. 24") and Presidential Regulation No. 63 of 2019 on Use of Bahasa Indonesia ("PR No. 63" and, together with Law No. 24, the "Indonesian Language Regulations"), agreements to which Indonesian parties are a party are required to be executed in Bahasa Indonesia, although, when a foreign entity is a party, the agreement may also be written in the English language or the national language of the relevant foreign party (in addition to the Bahasa Indonesia version). PR No. 63, however, expresses that the Bahasa Indonesia version of the agreement should be the original or master version, while the English version or the national language version of the foreign party is treated as an equivalent of, or a translation of, the Bahasa Indonesia version of the agreement. Under PR No. 63, in the event of a discrepancy or inconsistency, the prevailing language must be the language as agreed between the parties in the agreement.

The West Jakarta District Court issued a decision in June 2013, which voided a loan agreement on the basis that it was, among other reasons, not executed in Bahasa Indonesia. The decision of the court disagreed with the findings in the Ministry of Law and Human Rights Clarification Letter and concluded that until Law No. 24 is subject to judicial review before the Constitutional Court and amended, the requirement for agreements to which Indonesian entities are a party to be executed in Bahasa Indonesia remains, notwithstanding that a Presidential Regulation has not been enacted. In 2014 and 2015, the case was brought before the High Court of Jakarta and the Supreme Court, both of which affirmed the decision by the West Jakarta Court. The Supreme Court's affirmation on the case concludes that every agreement that falls within the ambit of the provisions of Law No. 24 must be executed in Bahasa Indonesia, although versions in other languages are allowed.

PR No. 63 remains inconclusive as to whether the agreements identified in the Indonesian Language Regulations entered into between Indonesian parties and non-Indonesian private institutions, and not set out in Bahasa Indonesia, would be invalid or unenforceable. However, the Indenture and certain other documents entered into in connection with the Program or any issue of Notes thereunder will be prepared in both English and Bahasa Indonesia versions and executed simultaneously, as permitted under the Indonesian Language Regulations, and, pursuant to the Indonesian Language Regulations, each version will be considered equally original. All of these documents will provide that in the event of any discrepancy or inconsistency, the parties agree that the English version would prevail and the Bahasa Indonesia version will be amended to conform with the provisions of the English version. Furthermore, some concepts in the English language may not have a corresponding term in Bahasa Indonesia, or may not be fully captured by the Bahasa Indonesia version. If this occurs, there can be no assurance that the Notes, the Indenture and the Program Agreement will be as described in this Offering Memorandum, or will be interpreted and enforced by the Indonesian courts as intended.

The Indonesian Language Regulations do not specify any sanction for non-compliance. We cannot predict as to how the implementation of this new regulation will impact the validity and enforceability of the Notes under Indonesian laws. This creates uncertainty as to the ability of holders of Notes to enforce the Notes in Indonesia.

CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2019. This table should be read in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our unaudited interim consolidated financial statements as of September 30, 2019 and 2018 and for the periods then ended and the related notes thereto included elsewhere in the Offering Memorandum. There have been no material changes to our capitalization since September 30, 2019.

	As of September 30, 2019
	(unaudited) (US$ in millions)
Indebtedness	
Short-term loans	1,918.3
Long-term liabilities — bank loans — net (including current portion)[1]	1,879.9
Due to the Government — two-step loans[2]	740.5
Bonds payables[3]	12,614.2
Total debt	17,152.9
Equity	
Share capital	
Authorized — 600,000,000 ordinary shares at par value of Rp. 1,000,000 (full amount) per share Issued and paid-up — 171,227,044 shares	16,191.2
Additional paid-in capital	(924.3)
Government contributed assets pending final clarification of status	398.6
Other equity components	220.8
Retained earnings	
— Appropriated	10,770.5
— Unappropriated	731.2
Total equity attributable to owners of the parent entity	27,387.9
Non-controlling interests	2,366.9
Total equity	29,754.8
Total capitalization[4]	**46,907.7**

Notes:

(1) Excludes US$83.0 million drawn after September 30, 2019 under the Jambaran-Tiung Biru Loan Agreement, which was entered into on June 13, 2019 by and among HSBC Bank USA, N.A., as trustee under a trustee borrowing structure for PEPC, MUFG Bank, Ltd., as agent, and various lenders and certain financial institutions named therein.

(2) Includes Government-channeled financings obtained from the Overseas Economic Cooperation Fund Japan, the Japan International Cooperation Agency, the International Bank for Reconstruction and Development and the Japan Bank for International Cooperation. See Notes 18b, 18c, 18d, 18h, 18i and 18j of our consolidated financial statements for more information on the two-step loans.

(3) Includes the following (all bonds issued by the Issuer unless otherwise noted): (i) US$1,000.0 million 2021 Notes and US$500.0 million 6.5% senior notes due 2041, both of which were issued in May 2011, (ii) US$1,250.0 million 2022 Notes (of which US$1,242.0 million 2022 Notes remains outstanding) and US$1,250.0 million 6.0% senior notes due 2042, both of which were issued in May 2012, (iii) US$1,625.0 million 4.3% senior notes due 2023 and US$1,625.0 million 5.625% senior notes due 2043, both of which were issued under the Program in May 2013, (iv) US$1,500.0 million 6.45% senior notes due 2044 issued under the Program in 2014, (v) US$1,350.0 million 5.125% senior notes due 2024, issued in 2014 by PGN, (vi) US$625 million 4.450% senior notes due 2024 issued in 2017 by PT Saka Energi Indonesia, (vii) US$750.0 million 6.5% senior notes due 2048, which were issued under the Program in November 2018, and (viii) US$750.0 million 3.65% senior notes due 2029 and US$750.0 million 4.70% senior notes due 2049, both of which were issued under the Program in July 2019. This amount is presented net of discount and issuance cost.

(4) Represents total debt plus total equity.

SELECTED CONSOLIDATED FINANCIAL AND OTHER DATA

The selected audited consolidated financial information as of and for the years ended December 31, 2018, 2017 and 2016 have been derived from our audited consolidated financial statements which are included in this Supplemental Offering Memorandum. The selected unaudited interim consolidated financial information as of September 30, 2019 and for the nine-month periods ended September 30, 2019 and 2018 have been derived from our unaudited interim consolidated financial statements included elsewhere in this Supplemental Offering Memorandum. These financial statements have been prepared on the same basis as our audited consolidated financial statements. Our results for any interim period may not be indicative of our results for the full year or for any other period.

You should read the following selected consolidated financial information in conjunction with our consolidated financial statements and related notes, "Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements," "Presentation of Financial and Other Data," "Selected Consolidated Financial and Other Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in the Offering Memorandum. Our consolidated financial statements have been prepared and presented in accordance with IFAS, which differs in certain respects from U.S. GAAP. In making an investment decision, you should rely upon your own examination of the terms of the offering of the Notes and the financial information included in the Offering Memorandum. You should consult your own financial advisors for an understanding of the differences between IFAS and other GAAP you may be more familiar with, including U.S. GAAP, and how these differences may affect the financial information included in the Offering Memorandum. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP" in the Original Offering Memorandum.

Consolidated Statement of Profit or Loss and Other Comprehensive Income Data

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Sales and other operating revenues					
Domestic sales of crude oil, natural gas, geothermal energy and oil products	35,841.7	39,788.8	44,742.5	33,388.3	32,429.5
Subsidy reimbursements from the Government	2,568.8	3,572.1	5,632.5	4,333.3	3,654.6
Export of crude oil, natural gas and oil products	968.4	1,874.3	3,637.0	2,668.1	2,484.0
Marketing fees	(257.5)	25.5	15.4	11.6	9.4
Revenues from other operating activities	690.5	740.1	3,906.2	2,786.4	597.3
Total sales and other operating revenues	**39,811.9**	**46,000.7**	**57,933.6**	**43,187.7**	**39,174.8**
Costs of sales and other direct costs					
Cost of goods sold	(26,181.0)	(33,175.7)	(42,787.9)	(31,219.6)	(29,113.0)
Upstream production and lifting costs	(3,270.0)	(3,421.2)	(4,386.5)	(3,454.9)	(3,573.5)
Exploration costs	(109.2)	(165.4)	(267.7)	(198.4)	(120.1)
Expenses from other operating activities	(703.5)	(863.0)	(1,272.0)	(1,011.0)	(1,252.5)
Total cost of sales and other direct costs	**(30,263.7)**	**(37,625.2)**	**(48,714.1)**	**(35,883.8)**	**(34,059.0)**
Gross profit	**9,548.3**	**8,375.5**	**9,219.5**	**7,303.9**	**5,115.7**
Selling and marketing expenses	(1,339.6)	(1,590.2)	(1,642.8)	(1,026.6)	(1,082.2)
General and administrative expenses	(1,509.3)	(1,598.9)	(1,329.9)	(963.5)	(1,129.3)
Gain (loss) on foreign exchange — net	(57.5)	58.1	19.6	(190.4)	140.5
Finance income	336.6	233.1	256.6	159.7	400.5
Finance costs	(770.5)	(817.7)	(835.2)	(619.4)	(721.2)
Share in net profit of associates and joint venture	18.7	37.9	122.7	178.2	59.7
Other expenses — net	(877.9)	(830.6)	(80.8)	(110.0)	(333.8)
	(4,199.4)	(4,508.3)	(3,489.9)	(2,572.0)	(2,665.7)
Profit before income tax	**5,348.9**	**3,867.2**	**5,729.6**	**4,731.9**	**2,450.0**
Income tax expense — net	(1,877.6)	(1,166.8)	(3,013.2)	(2,042.7)	(1,674.1)
Profit for the period/year after the effect of merging entity's income adjustment	**3,471.2**	**2,700.4**	**2,716.4**	**2,689.2**	**775.9**
Other Comprehensive (Loss) Income					
Items not to be reclassified to profit or loss in subsequent periods (net of tax)					
Remeasurement of net defined benefit liability	(73.4)	(129.1)	228.5	195.7	(37.7)
Items to be reclassified to profit or loss in subsequent periods (net of tax)					
Foreign exchange difference from translation of financial statements in foreign currency	14.7	7.1	(79.6)	124.6	73.0
Share of other comprehensive income (loss) of associates	1.5	(25.1)	(130.8)	(419.9)	(111.3)
Other comprehensive income (loss), net of tax	**(57.2)**	**(147.1)**	**18.2**	**(99.7)**	**(75.9)**
Total comprehensive income for the period/ year after the effect of merging entity's income adjustment	**3,414.0**	**2,553.3**	**2,734.6**	**2,589.5**	**699.9**
Adjustment of merging entity's income:					
Owners of the parent entity	(173.3)	(81.5)	(45.8)	(45.8)	—
Non-controlling interests	(135.2)	(66.2)	(34.6)	(34.6)	—
	(308.6)	**(147.8)**	**(80.4)**	**(80.4)**	**—**

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
				(Unaudited)	
			(US$ in millions)		
Profit for the period/year before the effect of merging entity's income adjustment attributable to:					
Owners of the parent entity	3,147.0	2,540.2	2,526.8	2,504.3	731.2
Non-controlling interests	15.6	12.4	109.3	104.6	44.7
	3,162.7	**2,552.6**	**2,636.0**	**2,608.9**	**775.9**
Adjustment of merging entity's comprehensive income:					
Owners of the parent entity	(177.0)	(80.7)	(42.5)	(42.5)	—
Non-controlling interests	(138.3)	(65.5)	(32.7)	(32.7)	—
	(315.2)	**(146.3)**	**(75.2)**	**(75.2)**	**—**
Total comprehensive income for the period/ year before effect of merging entity's income adjustment attributable to:					
Owners of the parent entity	3,081.5	2,363.3	2,536.6	2,455.5	344.4
Non-controlling interests	17.2	43.7	122.8	58.8	355.6
	3,098.8	**2,407.0**	**2,659.3**	**2,514.3**	**699.9**

Consolidated Statement of Financial Position Data

	As of December 31,			As of September 30,
	2016	2017	2018	2019
				(Unaudited)
		(US$ in millions)		
Assets				
Current assets				
Cash and cash equivalents	6,721.6	6,409.8	9,112.3	8,094.8
Restricted cash	122.7	119.7	108.9	239.5
Short-term investments	130.8	249.3	225.2	462.7
Trade receivables				
Related parties	1,422.3	1,095.0	1,297.7	1,711.5
Third parties	1,442.5	1,580.6	1,933.5	2,031.6
Due from the Government — current portion	1,792.5	1,492.6	1,834.3	2,119.2
Other receivables				
Related parties	242.8	255.1	149.2	218.0
Third parties	649.8	620.5	734.3	997.1
Inventories	4,795.0	6,036.1	6,323.2	5,519.1
Prepaid taxes — current portion	567.6	794.3	820.6	672.0
Prepayments and advances	503.4	476.3	535.0	540.3
Other investments	43.2	27.3	80.2	74.1
Total current assets	**18,434.1**	**19,156.6**	**23,154.2**	**22,679.9**
Non-current assets				
Due from the Government — net of current portion	—	663.1	2,924.1	3,161.2
Deferred tax assets	751.5	1,371.1	1,441.9	1,364.9
Long-term investments	3,329.4	2,970.9	2,819.1	2,673.4
Fixed assets	12,156.8	12,439.5	12,859.3	12,655.1
Oil and gas and geothermal properties	16,397.7	18,031.4	18,614.3	18,683.8
Prepaid taxes — net of current portion	1,469.8	829.3	820.3	983.0
Other non-current assets	1,436.9	1,977.5	2,085.3	2,335.3
Total non-current assets	35,542.0	38,282.8	41,564.2	41,856.7
Total assets	**53,976.1**	**57,439.4**	**64,718.5**	**64,536.6**
Liabilities and equity				
Short-term liabilities				
Short-term loans	230.3	452.9	4,347.0	1,918.3
Trade payables				
Related parties	118.5	49.3	78.8	157.0
Third parties	3,290.7	3,900.1	3,597.8	3,296.6
Due to the Government — current portion	952.5	1,050.6	1,207.7	1,520.7
Taxes payable				
Income taxes	475.6	308.8	467.6	498.1
Other taxes	251.6	250.5	258.4	256.5
Accrued expenses	1,596.6	2,019.9	2,135.5	2,366.4
Long-term liabilities — current portion	722.2	366.0	420.6	529.5
Other payables				
Related parties	50.9	56.6	54.0	32.5
Third parties	1,026.8	1,121.5	1,203.4	1,394.0
Deferred revenue — current portion	177.5	260.8	202.0	198.6
Total short-term liabilities	**8,893.2**	**9,837.0**	**13,972.9**	**12,168.2**

	As of December 31,			As of September 30,
	2016	2017	2018	2019
				(Unaudited)
		(US$ in millions)		
Long-term liabilities				
Due to the Government — net of current portion	732.6	780.6	795.1	818.7
Deferred tax liabilities	2,528.5	2,848.2	3,307.4	3,410.4
Long-term liabilities — net of current portion	2,716.9	2,109.8	1,805.3	1,507.5
Bonds payables	9,772.7	10,385.9	11,094.1	12,614.2
Employee benefit liabilities	2,058.7	2,208.2	1,850.4	2,013.5
Provision for decommissioning and site restoration	1,900.1	2,129.3	2,029.7	2,037.2
Deferred revenue — net of current portion	65.7	42.7	74.6	81.0
Other non-current payables	62.9	84.4	178.9	131.1
Total long-term liabilities	**19,838.1**	**20,589.1**	**21,135.5**	**22,613.6**
Total liabilities	**28,731.3**	**30,426.1**	**35,108.4**	**34,781.9**
Equity				
Equity attributable to owners of the parent entity				
Share capital				
Authorized — 600,000,000 (2019 and 2018) and 200,000,000 (2017 and 2016) ordinary shares at par value of Rp. 1,000,000 (full amount) per share,				
Issued and paid up — 171,227,044 shares (2019 and 2018) and 133,090,697 shares (2017 and 2016)	13,417.0	13,417.0	16,191.2	16,191.2
Additional paid-in capital	2.7	2.7	(924.3)	(924.3)
Merging entity's equity	1,801.7	1,804.6	—	—
Government contributed assets pending final clarification of status	1.4	1.4	401.1	398.6
Other equity components	664.6	487.7	607.6	220.8
Retained earnings				
Appropriated	4,631.4	6,871.1	8,796.4	10,770.5
Unappropriated	3,147.0	2,540.2	2,526.8	731.2
Total Equity Attributable to Owners of the Parent Entity	**23,666.0**	**25,124.7**	**27,598.7**	**27,387.9**
Non-controlling interest	1,578.8	1,888.5	2,011.3	2,366.9
Total equity	**25,244.8**	**27,013.3**	**29,610.0**	**29,754.8**
Total liabilities and equity	**53,976.1**	**57,439.4**	**64,718.5**	**64,536.6**

Consolidated Statement of Cash Flows Data

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Cash flows from operating activities:					
Cash receipts from customers	42,723.5	40,220.3	48,878.5	35,685.6	37,983.2
Cash receipts from the Government	3,722.3	3,787.9	7,805.6	4,644.3	4,728.6
Cash receipts from tax restitution	39.5	616.7	185.0	15.9	39.0
Payments to suppliers	(29,211.9)	(29,261.8)	(38,227.6)	(27,662.1)	(28,845.5)
Payments to the Government	(5,173.5)	(7,524.6)	(11,279.6)	(7,755.5)	(7,161.0)
Payments of corporate income taxes	(2,009.0)	(2,100.3)	(2,688.2)	(2,074.6)	(2,029.7)
Cash paid to employees and management	(1,321.4)	(1,540.8)	(1,640.9)	(1,206.0)	(1,468.3)
Receipts from (placement of) restricted cash	(494.0)	(156.0)	73.1	(6.8)	(11.5)
Receipts of interest	115.7	35.6	63.3	33.6	18.8
Net cash generated from operating activities	**8,391.2**	**4,076.9**	**3,169.4**	**1,674.3**	**3,253.5**
Cash flows from investing activities:					
Proceeds from disposal of short-term investment	45.8	99.9	198.4	65.3	98.0
Proceeds from disposal of long-term investments	4.6	15.8	—	—	—
Interest received from investments	4.0	18.2	13.8	25.8	9.3
Cash receipts from other investing activities	—	28.7	262.2	167.6	0.4
Proceeds from sale of fixed assets	2.2	0.1	0.2	0.3	1.1
Dividends received from associates	233.6	81.6	214.1	80.6	14.8
Purchases of fixed assets	(1,012.7)	(981.9)	(1,288.0)	(741.4)	(974.5)
Purchases of oil and gas and geothermal properties	(1,365.1)	(892.0)	(1,482.5)	(915.6)	(1,372.5)
Placements in long-term investments	(336.5)	(660.0)	(1,062.2)	(167.4)	(90.7)
Placements in short-term investments	(142.8)	(226.3)	(237.6)	(97.4)	(123.3)
Payments for exploration and evaluation assets	(18.4)	(37.2)	(99.5)	(173.8)	(30.5)
Placement of restricted cash	(10.3)	(29.4)	(22.6)	(21.9)	(0.0)
Addition of participating interest	(23.8)	—	—	—	—
Acquisition of subsidiary net of cash acquired	—	—	—	—	17.0
Cash obtained due to change of control	—	203.2	—	—	—
Net cash used in investing activities	**(2,619.4)**	**(2,379.3)**	**(3,503.8)**	**(1,778.0)**	**(2,450.8)**
Cash flows from financing activities:					
Proceeds from short-term loans	2,377.3	4,039.5	9,489.2	6,689.9	5,733.0
Proceeds from bond issuance	—	—	734.4	—	1,498.9
Proceeds from long-term loans	1,674.4	1,288.2	255.9	220.1	415.2
Repayments of short-term loans	(4,057.9)	(3,786.7)	(5,583.3)	(3,827.1)	(8,353.8)
Repayments of long-term loans	(2,248.4)	(2,109.0)	(465.4)	(443.4)	(518.4)
Dividend payments	(554.9)	(867.8)	(585.8)	(329.6)	(317.3)
Payments of finance costs	(530.8)	(523.1)	(538.5)	(275.8)	(336.2)
Repayments of bonds	(139.8)	—	(37.6)	(15.4)	—
Receipts from (placement of) restricted cash	0.4	(13.2)	(0.3)	(0.6)	(1.0)
Net cash generated from (used in) financing activities	**(3,479.6)**	**(1,972.2)**	**3,268.7**	**(2,018.1)**	**(1,879.7)**
Net increase (decrease) in cash and cash equivalents	**2,292.3**	**(274.6)**	**2,934.3**	**(1,914.5)**	**(1,077.0)**
Effect of exchange rate changes on cash and cash equivalents	20.7	(37.2)	(231.8)	(366.4)	59.5
Cash and cash equivalents at beginning of the period/year	**4,408.7**	**6,721.6**	**6,409.8**	**6,409.8**	**9,112.3**
Cash and cash equivalents at end of the period/year	**6,721.6**	**6,409.8**	**9,112.3**	**7,957.9**	**8,094.8**

Segment Results

The following table presents segment revenues and results for our upstream and downstream segments for the periods indicated. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in the Offering Memorandum. Our segment results are derived from our total segment revenues, after deducting total costs of sales and other direct costs, selling and marketing expenses and general and administrative expenses relating to such segments. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview of Segment Results."

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Total upstream segment revenues	6,272.3	7,966.3	12,552.6	8,371.0	8,890.5
Upstream segment results	2,065.7	3,327.9	5,960.6	4,367.2	3,835.7
Total downstream segment revenues	32,477.7	37,372.7	46,091.3	35,466.7	31,861.4
Downstream segment results	4,176.2	1,282.2	(286.8)	608.0	(1,336.2)

Non-GAAP and Other Financial Data

	As of or for the Years Ended December 31,			As of or for the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions, except ratios and percentages)	(Unaudited)	
Capital expenditure[1]	3,025.0	5,423.2	4,533.5	2,684.1	2,626.7
Interest expense[2]	531.3	564.1	581.0	428.5	607.2
Adjusted EBITDA[3]	8,162.4	7,108.0	9,204.4	7,330.9	5,152.9
Total debt[4]	13,895.5	13,824.2	18,245.5	14,800.6	17,152.9
Total debt/Adjusted EBITDA (times)	1.7	1.9	2.0	2.0[6]	3.3[6]
Adjusted EBITDA/Total sales and other operating revenues (%)	20.5	15.5	15.9	17.0	13.2
Total debt to Total equity (%)	55.0	51.2	61.6	51.0	57.6
Adjusted EBITDA/Interest expense (times)	15.4	12.6	15.8	17.1	8.5
Dividend payout ratio (%)[5]	39.1	27.6	23.1	—	—

Notes:

(1) Capital expenditure is comprised of additions to fixed assets, oil and gas and geothermal properties and long term investments — investments in oil and gas blocks-net. For details of our capital expenditure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of capital expenditure for the periods indicated:

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Additions of fixed assets	1,200.7	1,587.6	1,493.2	1,055.0	818.5
Additions of oil and gas, and geothermal properties	1,812.0	3,835.6	3,040.3	1,629.1	1,808.2
Additions of long term investments — investments in oil and gas blocks-net	12.3	—	—	—	—
Capital expenditure	**3,025.0**	**5,423.2**	**4,533.5**	**2,684.1**	**2,626.7**

(2) Interest expense is comprised of finance costs for short-term loans, long-term loans and bonds. For details of our loans and bonds, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and

Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of interest expense for the periods indicated:

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Finance Costs:					
Short-term loans	13.9	8.5	56.5	25.7	81.7
Long-term loans	183.2	203.0	172.6	142.8	110.6
Bonds	334.2	352.6	351.9	260.0	414.9
Interest expense	**531.3**	**564.1**	**581.0**	**428.5**	**607.2**

(3) We calculate Adjusted EBITDA by adding depreciation, depletion and amortization, finance costs and income tax expense — net to profit for the period/year before the effect of merging entity's income adjustment and subtracting finance income, in accordance with BUMN Regulation KEPMEN 100. BUMN Regulation KEPMEN 100 requires adjustment for all finance costs and does not take into account the effects of merging entity's income adjustment, which arise in connection with acquisitions during the year or period. In comparison, our calculations of EBITDA in the past adjusted for interest expense and not accretion expenses related to decommissioning and site restoration or other finance costs and took into account the effects of merging entity's income adjustment. Adjusted EBITDA and the related ratios presented in the Offering Memorandum are therefore not comparable to our previously disclosed EBITDA and related ratios.

Adjusted EBITDA is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP. Adjusted EBITDA is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with IFAS or U.S. GAAP or an alternative to cash flows from operating activities as a measure of liquidity. In addition, Adjusted EBITDA is not a standardized term, hence a direct comparison between companies using such term may not be possible. We have included Adjusted EBITDA because we believe it is an indicative measure of our operating performance and is used by investors and analysts to evaluate companies in our industry. The following table reconciles our net income under IFAS to our definition of Adjusted EBITDA for the periods indicated:

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Profit for the period/year before the effect of merging entity's income adjustment	3,162.7	2,552.6	2,636.0	2,608.9	775.9
Adjustments:					
Finance income	(336.6)	(233.1)	(256.6)	(159.7)	(400.5)
Finance costs	770.5	817.7	835.2	619.4	721.2
Income tax expense — net	1,877.6	1,166.8	3,013.2	2,042.7	1,674.1
Depreciation, depletion and amortization expense	2,688.2	2,804.0	2,976.6	2,219.6	2,382.2
Adjusted EBITDA	**8,162.4**	**7,108.0**	**9,204.4**	**7,330.9**	**5,152.9**

(4) Total debt is comprised of short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans and bonds payables. "Two-step loans" is comprised of: (i) the Ulubelu and Lahendong geothermal project loan, (ii) the Lumut Balai geothermal project loan, (iii) the Ngurah Rai Airport refueling facility construction project loan, (iv) the South Sumatera West Java gas transmission pipeline development project loan, (v) the Domestic Gas market development project loan and (vi) gas transmission and distribution project Phase II project loan. For details, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness."

(5) Dividend payout ratios are calculated as dividends paid during the year equivalents in U.S. dollars divided by the previous year's profit for the year before the effect of merging entity's income adjustment. Dividend payout ratio is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP. Dividend payout ratio is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income, or any other performance measure derived in accordance with IFAS or U.S. GAAP or an alternative to cash flow from operating activities as a measure of liquidity. In addition,

dividend payout ratio is not a standardized term, hence a direct comparisons between companies using such a term may not be possible. For details of our dividend payout ratios, see "Risk Factors — Risks Relating to Our Company — We are subject to the control of the Government and there is no guarantee that they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue." The following table reconciles our net income under IFAS to our definition of dividend payout ratios for the periods indicated:

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
				(Unaudited)	
	(US$ in millions except percentages)				
Dividend paid during the year equivalents in U.S. dollars	554.9	867.8	585.8	—	—
Prior profit for the year before merging entity's income adjustment attributable to owners of the parent entity	1,420.2	3,147.0	2,540.2	—	—
Dividend payout ratio (%)	**39.1**	**27.6**	**23.1**	**—**	**—**

(6) Total debt/Adjusted EBITDA ratios for the nine-month periods ended September 30, 2018 and 2019 are calculated based on total debt as of such dates and Adjusted EBITDA for the nine-month periods then ended. Therefore, they are not comparable to, and are higher than, our total debt/ Adjusted EBITDA ratios for the years ended December 31, 2016, 2017 and 2018, which are calculated using Adjusted EBITDA for the twelve-month periods then ended.

Selected Reserve, Production and Operating Data

Except where attributed to Wood Mackenzie, all information in the Offering Memorandum relating to oil and gas reserves is presented on the basis of our "net reserves" which represents our share of the gross reserves in a block, field or specified area, attributable to our working interest before deducting the share payable to the Government as owner of the reserves, pursuant to the terms of the relevant production sharing arrangement or cooperation contract and the cost recovery and any applicable taxes. In the Offering Memorandum, except where attributed to Wood Mackenzie, estimates of our oil and gas reserves as of September 30, 2019 have been prepared in a manner consistent with PRMS 2018, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007, and estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in the Offering Memorandum, estimates of our oil and gas reserves as of September 30, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves. For more information, see "Presentation of Financial and Other Information — Oil and Gas Reserves."

The information on our oil and gas production presented and referred to as "production" in the Offering Memorandum is our "net production" and represents our share of the oil and/or gas production from a block, field or specified area, attributable to our working interest before deducting the share payable to the Government pursuant to the terms of the relevant production sharing arrangement or cooperation contract and the cost recovery and any applicable taxes. See "Risk Factors — Risks Relating to Our Upstream Operations — Our crude oil, natural gas and geothermal reserve estimates are uncertain and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these reserves" and "Business — Pertamina Upstream Business — Reserves."

The following table sets forth the present value and estimated volume of our total net oil and gas proved and proved plus probable reserves.

	Crude Oil (mmbbls)	Natural Gas (bcf)	Combined (mmboe)
2019 (as of September 30, 2019)[1]			
Total net proved plus probable reserves (as of September 30, 2019)	**1,327.3**	**7,754.3**	**2,665.6**
Probable reserves	313.6	1,728.2	611.9
Total net proved reserves (as of September 30, 2019)	**1,013.7**	**6,026.1**	**2,053.8**
2018[1]			
Total net proved plus probable reserves (as of December 31, 2018)	**1,362.8**	**7,825.4**	**2,713.4**
Probable reserves	290.7	1,628.0	571.7
Total net proved reserves (as of December 31, 2018)	**1,072.0**	**6,197.4**	**2,141.7**
2017[1]			
Total net proved plus probable reserves (as of December 31, 2017)	**1,606.3**	**8,574.0**	**3,084.6**
Probable reserves	356.6	1,655.0	641.6
Total net proved reserves (as of December 31, 2017)	**1,249.7**	**6,919.0**	**2,443.0**
2016[1]			
Total net proved plus probable reserves (as of December 31, 2016)	**1,719.1**	**9,452.0**	**3,350.6**
Probable reserves	275.0	1,101.5	465.1
Total net proved reserves (as of December 31, 2016)	**1,444.2**	**8,350.5**	**2,885.4**

Note:

(1) Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, estimates of our oil and gas reserves as of September 30, 2019 have been prepared in a manner consistent with PRMS 2018. Estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. Estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

The following table sets forth our average daily oil and gas production and average realized sales prices for the periods indicated.

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
Average daily oil and gas production:					
Crude oil (mbbls/d)	311.6	341.7	393.4	384.0	409.9
Natural gas (mmcf/d)	1,960.9	2,035.4	3,058.9	3,059.5	2,805.1
Total (mboe/d)	**650.0**	**693.0**	**921.4**	**912.1**	**894.0**
Average realized sales prices:					
Crude oil (US$ per bbl)	39.8	51.2	70.6	70.3	65.2
Natural gas (US$ per mcf)	6.0	5.8	6.3	6.3	6.5

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with our consolidated financial statements and the related notes, "Presentation of Financial and Other Data," "Summary Consolidated Financial and Other Data" and "Selected Consolidated Financial and Other Data" included elsewhere in the Offering Memorandum. Our consolidated financial statements have been prepared and presented in accordance with IFAS, which differs in certain respects from U.S. GAAP. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP." Unless otherwise indicated, references in this section to years are to our fiscal year ended December 31 in such year.

Overview

We are a fully integrated national oil, gas and geothermal company, wholly owned by the Government and headquartered in Jakarta, Indonesia. We have an operating history of more than 60 years. We were established on December 10, 1957 and became an Indonesian limited liability company in 2003.

We are engaged in a broad spectrum of upstream and downstream oil, gas, geothermal, petrochemical and other energy operations. Our lines of business are organized into upstream and downstream sectors in accordance with Indonesian oil, gas and geothermal regulations. We are also mandated by the Government to distribute subsidized fuel, LPG and CNG in Indonesia and to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program and to encourage the use of CNG as an alternative fuel.

In April 2018, the Issuer acquired the Government's 56.96% interest shares in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. In December 2018, the Issuer transferred 51.0% of its stake in PT Pertamina Gas to PGN, which reduced the Issuer's effective total ownership in PT Pertamina Gas (including the Issuer's indirect stake through its ownership of PGN) from 100.0% to 78.05%. The transfer of Pertagas to PGN is intended to grow our gas business by creating an extensive and far-reaching distribution and transmission pipeline network in Indonesia and unlocking benefits of scale.

We derive our sales and other operating revenues primarily from sales of refined petroleum products, sales of crude oil and natural gas, sales of processed gas products, sales of steam and electricity and sales of petrochemical products.

Results of Operations

Unless otherwise indicated, our results of operations are presented and discussed below on a consolidated basis.

The following table provides a breakdown of our profit for the period after the effect of merging entity's income adjustment by showing each item in U.S. dollar amounts and as a percentage of sales and other operating revenue for the periods indicated. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in the Offering Memorandum.

	For the Nine-Month Periods Ended September 30,			
	2018		2019	
	(Unaudited) (US$ in millions, except percentages)			
		%		%
Total sales and other operating revenue	43,187.7	100.0	39,147.8	100.0
Total cost of sales and other direct costs	(35,883.8)	83.1	(34,059.0)	86.9
Total operating expenses and other non-operating income/(expenses)[1]	(2,572.0)	6.0	(2,665.7)	6.8
Profit before income tax	**4,731.9**	**11.0**	**2,450.0**	**6.3**
Income tax expense — Net	(2,042.7)	4.7	(1,674.1)	4.3
Profit for the period after the effect of merging entity's income adjustment	**2,689.2**	**6.2**	**775.9**	**2.0**

Note:

(1) Comprised of selling and marketing expenses, general and administrative expenses, gain (loss) on foreign exchange — net, finance income, finance costs, share in net profit of associates and joint venture, and other expenses — net.

The following tables provide a breakdown of our sales (before elimination of inter-segment sales and expenses) and the results for our upstream and downstream segments for the periods indicated.

Upstream

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(Unaudited) (US$ in millions)	
External upstream sales	7,988.4	4,699.2
Inter-segment sales	382.6	4,191.3
Total upstream segment revenues	**8,371.0**	**8,890.5**
Upstream segment results	**4,367.2**	**3,835.7**

Downstream

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(Unaudited) (US$ in millions)	
External downstream sales	34,504.8	31,383.1
Inter-segment sales	962.0	478.3
Total downstream segment revenues	**35,466.7**	**31,861.4**
Downstream segment results	**608.0**	**(1,336.2)**

The nine-month period ended September 30, 2019 compared with the nine-month period ended September 30, 2018

Total Sales and Other Operating Revenues

In the nine months ended September 30, 2019, our total sales and other operating revenues decreased by US$4,012.9 million, or 9.3%, to US$39,174.8 million from US$43,187.7 million in the nine months ended September 30, 2018. This decrease was primarily due to a decrease in subsidy reimbursements from the Government and a decrease in domestic sales of crude oil, natural gas, geothermal energy and oil products because of the lower selling prices of certain types of our products, as well as a decrease in revenues from other operating activities as further described below. The average price of the ICP in September 2018 was US$68.25 per barrel while in September 2019 it was US$62.03 per barrel and the average price of MOPS for gasoline (RON 88), automotive diesel oil (gas oil 0.25% sulfur) and aviation turbine fuel in September 2018 was US$82.79 per barrel, while in September 2019 it was US$74.23 per barrel.

In 2018, revenues from other operating activities primarily comprised a one-time additional amount of US$3,102.2 million from the Government pursuant to PR 43/2018 to compensate us for a shortfall between the formula price and the government price of diesel and premium fuels. We have applied to the Government for a similar additional reimbursement in relation to our sales in the nine months ended September 30, 2019. If our application is accepted by the Government, an increase in other operating revenues for the nine months ended September 30, 2019 would be recorded in our consolidated statement of profit or loss and comprehensive income for the year ended December 31, 2019. For more information, see Note 9a to our consolidated financial statements included elsewhere in this Supplemental Offering Memorandum.

In our upstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$519.5 million, or 6.2%, to US$8,890.5 million from US$8,371.0 million in the nine months ended September 30, 2018. This increase was primarily due to an increase of inter-segment sales, from US$382.6 million in September 30, 2018 to US$4,191.3 million in September 30, 2019, as a result of an increase in the number of intercompany transactions between the upstream and downstream segments during the period.

In our downstream segment, our total segment revenues before eliminations in connection with our accounts consolidation decreased by US$3,605.3 million, or 10.2%, to US$31,861.4 million from US$35,466.7 million in the nine months ended September 30, 2018. This decrease was primarily due to a decrease in external sales, from US$34,504.8 million in September 30, 2018 to US$31,383.1 million in September 30, 2019, and as compared to 2018 where we received a one-time additional amount from the Government. We are still awaiting the Government's approval of our application for a similar additional reimbursement in relation to our sales in the nine months ended September 30, 2019.

Total Cost of Sales and Other Direct Costs

In the nine months ended September 30, 2019, our total cost of sales and other direct costs decreased by US$1,824.8 million, or 5.1%, to US$34,059.0 million from US$35,883.8 million in the nine months ended September 30, 2018. This decrease was primarily due to a decrease in our cost of goods sold by US$2,106.7 million, or 6.7%, from US$31,219.6 million in the nine months ended September 30, 2018 to US$29,113.0 million in the nine months ended September 30, 2019 primarily as a result of reduced production costs of direct materials and imports of other oil products due to a decrease in the price of the ICP in the nine months ended September 30, 2019, as compared with the same period in 2018, as well as a decrease in exploration costs by US$78.3 million or 39.5% from US$198.4 million in the nine months ended September 30, 2018 to US$120.1 million in the nine

months ended September 30, 2019. Total cost of sales and other direct costs as a percentage of revenue increased from 83.1% in the nine months ended September 30, 2018 to 86.9% in the nine months ended September 30, 2019 primarily due to a decrease of revenues from other operating activities.

Segment Results

In the nine months ended September 30, 2019, our consolidated segment results after eliminations decreased by US$2,409.5 million, or 45.3%, to US$2,904.2 million from US$5,313.8 million in the nine months ended September 30, 2018. Our consolidated segment results after eliminations as a percentage of our total sales and other operating revenues for the nine months ended September 30, 2019 was 7.4% compared to 12.3% for the nine months ended September 30, 2018 primarily due to a decrease in downstream segment results before elimination.

In the nine months ended September 30, 2019, in our upstream segment, our results before eliminations decreased by US$531.5 million, or 12.2%, to US$3,835.7 million from US$4,367.2 million in the nine months ended September 30, 2018. This decrease was primarily due to a decrease in the price of the ICP in the nine months ended September 30, 2019, as compared with the same period in 2018.

In our downstream segment, our results before eliminations amounted to a loss of US$1,336.2 million in the nine months ended September 30, 2019 as compared to a gain of US$608.0 million in the nine months ended September 30, 2018 primarily due to an increase in production costs, as a result of lower selling prices set by the Government.

Operating Expenses and other Non-Operating Expenses — Net

In the nine months ended September 30, 2019, we had operating expenses and other non-operating expenses — net of US$2,665.7 million compared to operating expenses and other non-operating expenses — net of US$2,572.0 million in the nine months ended September 30, 2018, an increase of US$93.7 million or 3.6%. The increase was primarily attributable to (i) higher general and administrative expenses primarily due to an increase in salaries, wages, and other employee and rental expenses, (ii) higher selling and marketing expenses primarily due to increases in rentals and depreciation, (iii) higher finance costs related to bonds and short term loans, and (iv) higher other expenses — net primarily due to adjustments of fair value investments, provision for impairments in receivables and impairments of fixed assets, which were partially offset by (y) a gain on foreign exchange — net, and (z) higher finance income.

Income Tax Expense — Net

In the nine months ended September 30, 2019, our income tax expense — net decreased by US$368.5 million, or 18.0%, from US$2,042.7 million in the nine months ended September 30, 2018 to US$1,674.1 million in the nine months ended September 30, 2019. In the nine months ended September 30, 2019, we had lower current tax expense due to a decrease in revenue in our upstream segment, primarily as a result of a decrease in the price of the ICP in the nine months ended September 30, 2019, as compared with the same period in 2018. For these reasons, our effective tax rate (calculated as income tax expense — net divided by profit before income tax expense) was 68.3% in the nine months ended September 30, 2019 and 43.2% in the nine months ended September 30, 2018.

Profit for the Period After the Effect of Merging Entity's Income Adjustment

For the reasons described above, in the nine months ended September 30, 2019, our profit for the period after the effect of merging entity's income adjustment decreased by US$1,913.3 million, or

71.1%, to US$775.9 million from US$2,689.2 million in the nine months ended September 30, 2018. As a percentage of our sales and other operating revenue, profit for the period after the effect of merging entity's income adjustment decreased from 6.2% in the nine months ended September 30, 2018 to 2.0% in the nine months ended September 30, 2019.

Liquidity and Capital Resources

Our principal sources of liquidity consist of cash flows generated from operating activities, bank facilities and other debt financing, and our existing cash, cash equivalents and bank deposits. We believe that our future cash flows from operations, borrowing capacity (including under the Program) and cash and cash equivalents in hand will be sufficient to fund our planned capital expenditures and investments, debt maturities and our present working capital requirements. We regularly evaluate our current and future financing needs and may, depending on market conditions, access the capital markets opportunistically from time to time to strengthen our capital position, manage our debt maturity profile and provide us with additional liquidity. In particular, we may access the capital markets to fund a repurchase of all or a portion of one or more series of outstanding notes depending on market conditions. Our ability to obtain adequate financing or undertake any liability management actions may be limited by our financial condition and results of operations and the liquidity in and conditions of international and domestic financial markets.

The following table sets forth a summary of our consolidated cash flows for the periods indicated.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(Unaudited) (US$ in millions)	
Net cash generated from operating activities	1,674.3	3,253.5
Net cash used in investing activities	(1,778.0)	(2,450.8)
Net cash generated from (used in) financing activities	2,018.1	(1,879.7)
Net increase (decrease) in cash and cash equivalents	**1,914.5**	**(1,077.0)**
Effect of exchange rate changes on cash and cash equivalents	(366.4)	59.5
Cash and cash equivalents at beginning of the year	6,409.8	9,112.3
Cash and cash equivalents at end of the year	**7,957.9**	**8,094.8**

Net Cash Generated from Operating Activities

Net cash generated from operating activities includes funds provided by our operating activities and net cash inflows or outflows from changes in operating assets and liabilities.

Net cash generated from operating activities was US$3,253.5 million in the nine-month period ended September 30, 2019, which consisted primarily of aggregate cash receipts from customers, the Government and a tax restitution of US$42,750.8 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$39,504.5 million. The increase in net cash generated from operating activities in the nine-month period ended September 30, 2019, as compared to the same period in 2018, was primarily attributable to an increase in cash receipts from customers due to more favorable exchange rates, an increase in cash receipts by subsidiaries from the Government as well as a decrease in payments to the Government, which were partially offset by an increase in payments to suppliers due to an increase in the volume of purchases and an increase in cash paid to employees and management due to an increase in personnel.

Net cash generated from operating activities was US$1,674.3 million in the nine-month period ended September 30, 2018, which consisted primarily of aggregate cash receipts from customers, the

Government and a tax restitution of US$40,345.8 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$38,698.2 million.

Net Cash Used in Investing Activities

Net cash used in investing activities was US$2,450.8 million in the nine months ended September 30, 2019, and US$1,778.0 million in the nine months ended September 30, 2018. These amounts are primarily attributable to (i) purchases of fixed assets of US$974.5 million in the nine months ended September 30, 2019 and US$741.4 million in the nine months ended September 30, 2018, (ii) purchases of oil and gas and geothermal properties of US$1,372.5 million in the nine months ended September 30, 2019 and US$915.6 million in the nine months ended September 30, 2018, (iii) placements in short- and long-term investments of US$213.9 million in the nine months ended September 30, 2019 and US$264.9 million in the nine months ended September 30, 2018 and (iv) dividends received from associates of US$14.8 million in the nine months ended September 30, 2019 and US$80.6 million in the nine months ended September 30, 2018.

Net Cash Generated from (Used in) Financing Activities

We recorded net cash used in financing activities of US$1,879.7 million in the nine months ended September 30, 2019, US$1,972.2 million in 2017 and US$3,479.6 million in 2016. We recorded net cash generated from financing activities of US$2,018.1 million in the nine months ended September 30, 2018 and US$3,268.7 million in 2018.

Our net cash used in financing activities of US$1,879.7 million in the nine months ended September 30, 2019, consisted primarily of proceeds from short-term loans of US$5,733.0 million and proceeds from bond issuance of US$1,498.9 million and proceeds from long-term loans of US$415.2 million. This was offset by repayments of short-term loans of US$8,353.8 million, repayments of long-term loans of US$518.4 million, payments of finance costs of US$336.2 million and placement of restricted cash of US$1.0 million.

Our net cash generated from financing activities of US$2,018.1 million in the nine months ended September 30, 2018, consisted primarily of proceeds from short-term loans of US$6,689.9 million and proceeds from long-term loans of US$220.1 million. This was offset by repayments of short-term loans of US$3,827.1 million, repayments of long-term loans of US$443.4 million, dividend payments of US$329.6 million, payments of finance costs of US$275.8 million, a repayment of bonds of US$15.4 million and placement of restricted case of US$0.6 million.

Indebtedness

The following table shows the amount of our total consolidated short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans, and bonds payables outstanding as of September 30, 2018 and 2019.

	As of September 30, 2018	As of September 30, 2019
	(Unaudited) (US$ in millions)	
Short-term loans	3,306.5	1,918.3
Long-term liabilities — bank loans — net (including current portion)	405.2	1,879.9
Due to the Government — two-step loans[(1)]	709.1	740.5
Bonds payables	10,379.8	12,614.2
Total debt	**14,800.6**	**17,152.9**

Note:

(1) Includes Government-channeled financings obtained from the Overseas Economic Cooperation Fund Japan, the Japan International Cooperation Agency, the International Bank for Reconstruction and Development and the Japan Bank for International Cooperation. See Notes 18b, 18c, 18d, 18h, 18i and 18j of our consolidated financial statements for more information on the two-step loans.

As of September 30, 2019, the current portion of our long-term bank loans without taking account any issuance costs-net was US$529.5 million and the non-current portion was US$1,507.5 million.

Short-Term Loans

As of September 30, 2019, we have access to unsecured short-term credit facilities in the form of letters of credit post import financing of up to an aggregate of US$10,757.0 million and Rp. 2,000.0 million. These facilities are denominated in U.S. dollars and Rupiah and provided by several Indonesian and international banks, including Mandiri (Persero) Tbk., PT Bank Negara Indonesia (Persero) Tbk., PT Bank Rakyat Indonesia (Persero) Tbk., PT Bank Central Asia Tbk., PT Bank Permata Tbk., PT Bank Bukopin Tbk, PT Bank HSBC Indonesia, UOB Indonesia, Standard Chartered Indonesia, PT Bank Tabungan Pensiunan Nasional (which was previously known as PT Bank Sumitomo Mitsui Indonesia), The Bank of Tokyo-Mitsubishi UFJ, LTD., PT Bank DBS Indonesia, PT Bank Mizuho Indonesia, PT Bank Maybank Indonesia Tbk, ANZ Jakarta, Deutsche Bank AG Jakarta, Banque Nationale de Paris Paribas, Singapore Branch, Crédit Agricole Corporate Investment Bank, Singapore Branch, Natixis, Singapore Branch, Citibank, N.A. Indonesia, JP Morgan Singapore Pte. Ltd., Societe Generale, Sumitomo Mitsui Banking Corporation, Singapore Branch and Intesa Sanpaolo Singapore, which we use in connection with our trading activities, of which we have utilized cumulatively US$3,067.0 million as of September 30, 2019. Drawdowns from these facilities are subject to further approvals of the relevant financial institutions. These short-term revolving credit facilities will expire in accordance with their terms in the course of each financial year.

The terms of our short-term revolving credit facilities include a number of customary covenants, undertakings and events of default that, among other things, restrict, our ability to create liens, sell assets, engage in different business activities or effect a consolidation or merger, subject to certain exceptions, and require us to provide certain financial information to our lenders. In addition, some facility agreements require that the Government of Indonesia continue to maintain a minimum percentage of ownership in our company, for example, 50.0% of our equity share capital, or the right to otherwise direct our policies or operations.

Long-term Liabilities — Bank Loans

Our long-term loans outstanding as of September 30, 2019 consisted of both Rupiah and foreign currency obligations. The following table shows the currency denomination of our outstanding long-term bank and two-step loans and bonds as of September 30, 2019.

	U.S. dollar (in millions)	Japanese Yen (in billions)
Total long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans and bonds	14,784.0	48.6

Bonds

As of September 30, 2019, we have issued US$1,000.0 million 2021 Notes, US$500.0 million 6.50% senior notes due 2041, US$1,250.0 million 2022 Notes (of which US$1,242.0 million 2022

Notes remains outstanding), US$1,250.0 million 6.00% notes due 2042, US$1,350.0 million 5.125% notes due 2024 and US$625.0 million 4.450% notes due 2024.

We established the Program on May 3, 2013 and increased the Program Limit from US$5,000.0 million to US$10,000.0 million in 2014. As of September 30, 2019, we have issued, under the Program, US$1,625.0 million 4.30% senior notes due 2023, US$1,625.0 million 5.625% senior notes due 2043, US$1,500.0 million 6.45% senior notes due 2044, US$750.0 million 6.50% senior notes due 2048, US$750.0 million 3.65% senior notes due 2029 and US$750.0 million 4.70% senior notes due 2049. We regularly evaluate our current and future financing needs and may opportunistically pursue financing opportunities from time to time, including through further issuances of Notes under the Program, if we consider market conditions to be favorable.

As of September 30, 2019, our subsidiary PGN has issued US$1,350.0 million 5.125% senior notes due 2024 and our subsidiary PT Saka Energi Indonesia has issued US$625.0 million 4.45% senior notes due 2024.

All of these notes are unsecured.

The interest rates on our long-term banks loans and bonds during 2017, 2018 and 2019 are set forth in the table below. All bonds were issued by the Issuer unless otherwise noted.

	2017	2018	2019
Rupiah long-term loans	7.25% – 13.00%	2.35% – 13.00%	7.40% – 9.75%
U.S. dollar long-term loans	1.37% – 3.51%	1.37% – 5.60%	1.37% – 4.65%
Senior notes due 2021	5.25%	5.25%	5.25%
Senior notes due 2022	4.88%	4.88%	4.88%
Senior notes due 2023	4.30%	4.30%	4.30%
Senior notes due 2024[(1)]	4.45%	4.45%	4.45%
Senior notes due 2024[(1)]	5.13%	5.13%	5.13%
Senior notes due 2029	n/a	n/a	3.65%
Senior notes due 2041	6.50%	6.50%	6.50%
Senior notes due 2042	6.00%	6.00%	6.00%
Senior notes due 2043	5.63%	5.63%	5.63%
Senior notes due 2044	6.45%	6.45%	6.45%
Senior notes due 2048	n/a	6.50%	6.50%
Senior notes due 2049	n/a	n/a	4.70%

Note:

(1) Issued by our subsidiaries.

Capital Expenditures

Our capital expenditures relate primarily to our exploration, development and production projects, to purchase interests in other companies engaged in exploration, development and production projects, the maintenance and upgrading of our refineries and repayments of outstanding debt. Our principal sources of funding for our capital expenditures consist of cash flows generated from operating activities, project financing arrangements and other debt financing, and our existing cash, cash equivalents and bank deposits.

The following table sets out our actual capital expenditures by business segment for the nine-month periods ended September 30, 2018 and 2019.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(Unaudited) (US$ in millions)	
Upstream	1,608.3	1,833.6
Downstream	713.6	572.0
Others	362.2	221.1
Total	**2,684.1**	**2,626.7**

We consider any purchase orders which are outstanding as of a period to be our outstanding capital expenditure commitments for such period. In the nine months ended September 30, 2019 and 2018, our capital expenditures were US$2.63 billion and US$2.68 billion, respectively.

The following table sets out our budgeted capital expenditures, which remains subject to the approval of the Minister of State-Owned Enterprises, by business sector for the year ending December 31, 2020 excluding PGN. Our budgeted capital expenditures include amounts budgeted for upstream exploration and drilling, investments in grass roots refineries, upgrades to existing refineries and gas infrastructure and potential growth through domestic and international acquisitions in each year and other uncommitted capital expenditures. This information reflects our current expectations only and our actual capital expenditures in any such year may differ materially from the projections set out below. See "Risk Factors — Risks Relating to Our Company — We may be unable to accomplish our development plans on schedule or within our budgeted costs or that these plans, if completed, will achieve our development aims" and "Risk Factors — Risks Relating to our Company — Our business is capital intensive, and if we are unable to obtain financing on reasonable terms to fund future capital expenditures, we may be unable to implement our development plans."

	For the Year Ending December 31, 2020
	(US$ in millions)
Upstream	
Oil and gas exploration and production	3,437
Geothermal	104
Drilling services	176
Total	**3,717**
Downstream	
Refining	2,170
Marketing and trading	854
Shipping	87
Total	**3,111**
Gas	**780**
Non-Core businesses	**201**
Total	**7,809**

As of September 30, 2019, our unrealized total outstanding capital expenditure commitments amounted to US$2,171.8 million.

Contractual Obligations

The following table summarizes our contractual financial liabilities (including anticipated interest payable) and operating lease commitments as of September 30, 2019.

	Total	Less than 1 year	1-5 Years	More than 5 Years
		(US$ in millions)		
Short-term loans	1,918.3	1,918.3	—	—
Trade payables	3,453.6	3,453.6	—	—
Due to the Government	2,503.5	1,544.7	317.5	641.3
Accrued expenses	2,142.0	2,142.0	—	—
Other payables	1,426.5	1,426.5	—	—
Long-term liabilities	2,101.9	458.6	1,360.8	282.5
Bonds payables	21,751.8	549.7	7,633.0	13,569.1
Other non-current payables	131.1	—	91.5	39.6
Total	**35,428.7**	**11,493.4**	**9,402.8**	**14,532.5**
Operating lease commitments	983.3	456.5	480.2	46.6

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that we believe have or are reasonably likely to have a current or future material effect on our financial condition, change in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Inflation

According to the Central Bureau of Statistics (Badan Pusat Statistik, formerly known as Biro Pusat Statistik) Indonesia, Indonesia's annual overall inflation rate as measured by the consumer price index was approximately 2.7% in 2019.

Market Risks

Foreign Exchange Risks

As export sales of crude oil, condensate and gas are determined and paid in U.S. dollars, while domestic sales of refined products are conducted in Rupiah, but based on market prices denominated in U.S. dollars, approximately 80% of our revenues are directly or indirectly denominated in U.S. dollars which reduces our exposure for foreign exchange risks.

A significant portion of our long-term total debt is denominated in U.S. dollars. The following table sets forth certain information regarding our U.S. dollar long-term total debt exposure for the periods indicated.

	As of September 30, 2019
	(Unaudited) (US$ in millions, except percentages)
Total U.S. dollar long-term liabilities — bank loans — net (including current portion) and bonds payables	14,494.1
Total U.S. dollar long-term liabilities — bank loans — net (including current portion) and bonds payables as a percentage of total long-term bank loans (including current portion) and bonds payables	98.9%

A strengthening or weakening of the Rupiah against the U.S. dollar would have increased or decreased equity and profit or loss by the amounts shown below. This analysis is based on foreign

currency exchange rate variances that were considered to be reasonably possible at the dates indicated below. The analysis assumes that all other variables, in particular interest rates, remain constant and excludes any impact on forecasted sales and purchases.

	Strengthening		Weakening	
	Equity	Profit or loss	Equity	Profit or loss
	(US$ in millions)			
September 30, 2019				
(Rupiah 3% movement)	361.3	355.7	(340.3)	(335.0)

Interest Rate Risks

As of September 30, 2019, US$6,003.3 million, or 28.6%, of our financial assets and US$3,823.6 million, or 15.3%, of our financial liabilities carried floating interest rates, and US$6,059.2 million, or 28.9%, of our financial assets and US$13,605.6 million, or 54.3%, of our financial liabilities carried fixed interest rates. A change of 0.2% in floating interest rates as of September 30, 2019 would have increased or decreased income before tax by US$4.4 million. This analysis assumed that all other variables, in particular foreign currency rates, remain constant.

Credit Risk

As of September 30, 2019, we had trade receivables of US$3,743.1 million, 45.7% of which was owed to us by our related parties, and our largest trade receivable balances were due from the Indonesian Armed Forces and Ministry of Defense, in the amount of US$432.0 million, PT Garuda Indonesia (Persero) Tbk, in the amount of US$401.8 million, PLN and its subsidiaries, in the amount of US$345.7 million. As of September 30, 2019, we made provisions for impairment of trade receivables from third parties of US$210.1 million and for impairment of trade receivables from related parties of US$53.6 million. Based on our management's review of the collectability of each balance of trade receivables as of September 30, 2019, our management was of the view that the provision for impairments of trade receivables was adequate.

Liquidity Risk

As of September 30, 2019, we had cash and cash equivalents of US$8,094.8 million.

Recent Accounting Pronouncements

The following are several accounting standards issued by the Indonesian Financial Accounting Standards Board ("DSAK") that are considered relevant to our financial reporting, but were not yet effective for consolidated financial statements as of September 30, 2019 and December 31, 2018, 2017 and 2016 and the nine-month periods ended September 30, 2019 and 2018 and the years ended December 31, 2018, 2017 and 2016:

The following standards have been issued and became effective on January 1, 2020:

- *Amendments to SFAS 15: Investment in Associates and Joint Ventures*;
- *Amendments to SFAS 62: Insurance Contracts*;
- *SFAS 71: Financial Instruments*;

- *SFAS 72: Revenue from Contracts with Customers*;
- *SFAS 73: Leases*;
- *Amendment of SFAS 71: Financial Instruments*;
- *Amendment of SFAS 1: Presentation of Financial Statements and SFAS 25: Accounting Policies, Changes in Accounting Estimates and Errors*; and
- *SFAS 1 (2019 Annual Improvements): Presentation of Financial Statements*.

The following standard that has been issued and will become effective on January 1, 2021:

- *Amendment of SFAS 22: Business Combinations on Business Definitions*.

We are currently evaluating and have not yet determined the effects of these accounting standards on our consolidated financial statements. See "Supplemental Risk Factors — Risks Relating to Our Company — Changes to IFAS standards for lease accounting may adversely affect our financial results and position." For more information, see Note 2b to our consolidated financials statements included elsewhere in this Supplemental Offering Memorandum.

INDONESIAN REGULATORY FRAMEWORK

The following sub-sections in the Indonesian Regulatory Framework section on page 155 to page 183 of the Original Offering Memorandum shall be amended and supplemented, where applicable, with the following information:

Indonesian Regulation of Offshore Borrowings

Pursuant to Presidential Decree No. 39 of 1991, we are required to obtain prior approval from the PKLN Team to receive offshore borrowings and must submit periodic reports to the PKLN Team. However, the decree does not stipulate either the time frame or the format and the content of the periodic report that must be submitted. Under Presidential Decree No. 59 of 1972, dated October 12, 1972, as partly revoked by the Presidential Decree No. 15 of 1991 on Receipt of Offshore Loans and Issuance of Bank Guarantees for the Acceptance of Offshores Loans by State-Owned Banks and Regional Development Banks Stipulated as Foreign Exchange Banks ("PD 59/1972"), we are required to obtain approval from the Minister of Finance of Indonesia and report the particulars of our offshore commercial borrowings to the Minister of Finance of Indonesia and Bank Indonesia, on the acceptance, implementation, and repayment of principal and interest. In practice, this approval from the Minister of Finance under PD 59/1972 is considered to have been obtained when approval from the PKLN Team is received because the Minister of Finance is a member of the PKLN Team. The Minister of Finance Decree No. KEP-261/MK/IV/5/1973 dated May 3, 1973, as amended by the Minister of Finance Decree No. 417/KMK.013/1989 dated May 1, 1989 and partly revoked by the Minister of Finance Decree No. 279/KMK.01/1991 dated March 18, 1991, as the implementing regulation of this PD 59/1972, further sets forth the requirement to submit periodic reports to the Minister of Finance of Indonesia and Bank Indonesia on the effective date of the contract and each subsequent three-month period.

On December 31, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/22/PBI/2014 on the Reporting of Foreign Exchange Activities and of Reporting Application of Prudential Principles in relation to an Offshore Loan Management for Non-Bank Corporation, as partly revoked by Bank Indonesia Regulation No. 21/2/PBI/2019 on the Reporting of Foreign Exchange Traffic Activities ("PBI 16/22/2014"). Under PBI 16/22/2014, any non-bank entity engaged in activities that cause a movement of (i) financial assets and liabilities between an Indonesian citizen and a non-citizen; or (ii) offshore financial assets and liabilities between Indonesian citizens, must submit a foreign exchange traffic report with respect to any foreign exchange activities to Bank Indonesia. Non-bank entities include state owned entities, regional government-owned enterprises, private enterprises and other entities that are not enterprises, whether in the form of legal entities or non-legal entities established by government or the public. The report must include, among other things, information relating to (i) the trading of goods, services or other transactions between an Indonesian citizen and a non-citizen; (ii) the entity's position with respect to or changes in its offshore financial assets and/or liabilities; and/or (iii) any plans to incur offshore loans and/or its implementation. In addition, PBI 16/22/2014 requires any non-bank entity which applies prudential principles to submit reports which comprise (i) a report on the implementation of prudential principles (ii) a report on the implemental of prudential principles which has complied with an attestation procedure conducted by a public accountant; (iii) notification of compliance of credit ratings; and (iv) financial statements. Bank Indonesia requires reports to be submitted monthly through an online system by the 15th day of the following month. In the event that there is a correction that needs to be made, the correction must be submitted by no later than the 20th day of the reporting month through the online system. The report on the implementation of prudential principles is required to be submitted quarterly or on any other submission deadline set forth in PBI 16/22/2014.

The following regulations further describe the reporting obligations of PBI 16/22/2014:

(a) under the Member of the Board of Governors of Bank Indonesia Regulation No. 21/4/PADG/2019 on the Reporting of the Activities of Foreign Exchange Flow in the

Form of Foreign Debts and Risk Participation Transactions ("PADG 21/4"), an Offshore Loan ("OL") is a loan from a resident to a non-resident in foreign currency and/or rupiah, including financing based on sharia principles, and a Risk Participation Transaction ("RPT") is a risk-transfer transaction for an individual credit facility and/or other facilities based on a master risk participation transaction. Banks, non-bank financial institutions and non-financial institution entities must submit reports for all OLs or RPTs regardless of the transaction value. The reports could consist of any one of, or a combination of, the following: (a) a main data report of the OL or RPT, (b) a recapitulation data report of the OL or RPT that includes (i) the withdrawal or payment plan of the OL or RPT, (ii) the realization of withdrawals or payment of the OL or RPT and (iii) the position and change of OL or RPT or (c) a new plan or an amendment of the OL. The OL or RPT main data report, recapitulation data report, new plan or amendment report must be submitted to Bank Indonesia no later than the 15th day of the following month, and a monthly recapitulation data report must be submitted to Bank Indonesia by no later than the 15th day following the signing, issuance or acknowledgement of the OL or RPT;

(b) under PADG 21/4, an Indonesian company that intends to obtain an offshore loan is required to submit a report to Bank Indonesia by no later than March 15 of each year in relation to such loan. In the event there is a change to the company's plan to obtain an offshore loan, any amendment to such report must be submitted to Bank Indonesia by no later than June 15 of the year of such change;

(c) under the Member of the Board of Governors of Bank Indonesia Regulation No. 21/7/PADG/2019 on the Reporting of Foreign-Exchange Activities by Non-Bank Institutions, which has been in effect since April 12, 2019, the type of reports required are as follows: (a) report of trading transactions involving goods, services and other transactions which are undertaken between residents and non-residents; (b) report of positions and changes of foreign financial assets; (c) report of positions and changes of equity of non-residents and other related liabilities; (d) report of positions and changes of foreign derivative liabilities; (e) report of position of foreign commitments and contingencies; and (f) report of position of securities owned by custodian customers. The non-bank reporter (i.e. non-bank financial institutions, non-financial-institution enterprises and other institutions) is required to submit monthly reports with respect to the foreign exchange activities carried out by the non-bank reporter to Bank Indonesia by no later than the 15th day of the following months; and

(d) under Bank Indonesia Circular Letter No. 17/3/DSta dated March 6, 2015, as amended by Bank Indonesia Circular No. 17/24/DSta dated October 12, 2015 on the Reporting Application of Prudential Principles in relation to an Offshore Loan Management for Non-Bank Corporation, a non-bank corporation must submit reports on the following: (i) a prudential principle report on quarterly basis; (ii) a prudential principle report that has been through attestation procedure no later than the end of June of each year; (iii) information on credit ratings on a monthly basis; and (iv) unaudited quarterly financial statements on a quarterly basis and audited annual financial statements (audited) that must be reported no later than the end of June of each year.

Any delay in submitting a foreign exchange report listed above may result in fines or administrative sanctions.

On May 14, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/10/PBI/2014 as amended by Bank Indonesia Regulation No. 17/23/PBI/2015 dated December 28, 2015 on the Receipt of Foreign Exchange Export Revenue and Withdrawal of Foreign Exchange Offshore Loan, as partly

revoked by Bank Indonesia Regulation No. 21/14/PBI/2019 on Foreign Exchange Export Proceeds and Foreign Exchange Import Payments ("PBI 16/10/2014"), as implemented by, among others, Bank Indonesia Circular Letter No. 18/5/DSta dated April 6, 2016 on Withdrawal of Foreign Exchange Loan. Under PBI 16/10/2014, an Indonesian debtor is required to withdraw, through foreign exchange banks located in Indonesia, its foreign currency offshore loan (i) obtained under a non-revolving loan agreement that is not used for refinancing; (ii) resulted from the difference between the amount of a refinancing facility and the relevant refinanced existing loan; or (iii) incurred under debt securities (i.e. bonds, medium-term notes, floating rate notes, promissory notes and commercial papers). The Indonesian debtor must report such withdrawal, along with any relevant supporting documents, to Bank Indonesia at the latest on the 15th day of the following month. Late submission may be subject to fines.

PBI 16/10/2014 further stipulates that the accumulated amount of withdrawals for an offshore loan must be equal to the commitment amount of such offshore loan as stated under the relevant offshore loan agreement. If the difference between the accumulated amount of withdrawals and the commitment amount of the offshore loan exceeds Rp. 50 million (or its equivalent in foreign currencies), the Indonesian debtor must provide a written explanation for such difference and sufficient supporting documents to Bank Indonesia before the expiration of the term of the applicable loan. An Indonesian debtor must report the withdrawal of an offshore loan to Bank Indonesia monthly using the recapitulation data report as regulated under PADG 21/4. Failure to provide a written explanation will be deemed as a violation of PBI 16/10/2014. Any violation of PBI 16/10/2014 will subject Indonesian debtors to fines for each non-complying withdrawal.

On December 29, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/21/PBI/2014, as amended by Bank Indonesia Regulation No. 18/4/PBI/2016 dated April 21, 2016 on the Application of Prudential Principles in Management of Offshore Loan of Non-Bank Corporations ("PBI 16/21/2014"). PBI 16/21/2014 requires non-bank corporations that obtain offshore borrowings in foreign currency (other than for trade credit) to maintain the following (the "Prudential Principles"):

(a) foreign currency exchange rate exposure must be hedged with a minimum hedging ratio equal to 25.0% of the difference between foreign currency assets and foreign currency liabilities;

(b) the ratio of foreign exchange assets to foreign exchange liabilities must be at least 70.0% and at the end of each quarter, such non-bank corporation must have sufficient foreign currency assets to cover the foreign currency liabilities that will be due to subsequent three months; and

(c) the non-bank corporation must have a credit rating of BB-or higher from a credit rating institution recognized by Bank Indonesia.

PBI 16/21/2014 also requires that such hedging transactions be conducted only with banks in Indonesia with effect from January 2017. In addition, the Issuer is specifically exempted from the minimum credit rating requirement.

The application of Prudential Principles does not apply to offshore loans in foreign currency that are in the form of trade credit, which refers to debt arising from credit that is granted by offshore suppliers over transactions relating to goods and/or services. Exemptions from the requirement to satisfy the minimum credit rating requirement apply for (i) the refinancing of offshore loans in foreign currency; (ii) offshore loans in foreign currency from (a) international bilateral/multilateral institutions; and (b) syndicated loans, with the contribution of international bilateral/multilateral institution exceeding 50.0%, in relation to financing for infrastructure projects; (iii) offshore loans in foreign currency in relation to government (central and regional) infrastructure project; (iv) offshore

loans in foreign currency that are guaranteed by international bilateral/multilateral institution; (v) offshore loans in foreign currency that are in the form of trade credit; (vi) offshore loans in foreign currency that are in the form of other loans, which refer to any other loan than loan agreement, debt securities and trade credit that are, among others, payment of insurance claim and unpaid dividend; (vii) offshore loans in foreign currency of finance companies, provided that, when the OJK last determined the soundness level (*tingkat kesehatan*) of the relevant finance company, the finance company had a minimum soundness level and fulfilled the maximum gearing ratio requirement as regulated by OJK; and (viii) offshore loans in foreign currency incurred by Indonesian Export Financing Institution (*Lembaga Pembiayaan Ekspor Indonesia* or "LPEI").

Under PBI 16/21/2014, non-bank corporations are required to report to Bank Indonesia with respect to their implementation of the Prudential Principles. Further, failure to comply on the fulfillment of the Prudential Principles will result in administrative sanctions in the form of a warning letter of which the relevant creditor(s) and certain government institutions will be notified. PBI 16/21/2014 became effective as of January 1, 2015.

Indonesian Regulations on Placement of Foreign Exchange Export Proceeds Deriving From Natural Resources

On January 10, 2019, the Government of Indonesia enacted Government Regulation No. 1 of 2019 on Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or Management Activities ("GR 1/2019"). Furthermore, on January 18, 2019, Bank Indonesia issued Bank Indonesia Regulation No. 21/3/PBI/2019 on the Receipt of Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or Management Activities ("PBI 21/3/2019"), which has been revoked by Bank Indonesia Regulation No. 21/14/PBI/2019 on Foreign Exchange Export Proceeds and Foreign Exchange Import Payments ("PBI 21/14/2019"), except for provisions on information submission and reporting in relation to export proceeds derived from transactions involving natural resources (*Devisa Hasil Ekspor dari Barang Ekspor Sumber Daya Alam* or the "DHE SDA") under PBI 21/3/2019, which remain applicable for all DHE SDA that are received until December 31, 2020.

GR 1/2019 and PBI 21/14/2019 require that the DHE SDA is (i) deposited in a special account maintained in a Foreign Exchange Bank in Indonesia (as defined in GR 1/2019); and (ii) utilized only for specific purposes, which are for the payments of: (a) export duties and other levies that apply to exports; (b) loan repayments; (c) importation activities; (d) profits or dividends; and/or (e) other purposes as regulated under Article 8 of Law No. 25 of 2007 on Investment. The types of exported goods which fall under the scope of GR 1/2019 and PBI 21/14/2019 are set out and elaborated under Decree of the Minister of Finance No. 1523/KM.4/2019 on the Determination of Natural Resources Export Goods with the Obligation to Insert Foreign Exchange Export Proceeds into the Financial System of Indonesia. The utilization of the DHE SDA for the purposes aforementioned must be accompanied by supporting documents. In the event that an exporter makes the payments as described above through an escrow account, such exporter must open an escrow account in a Foreign Exchange Bank in Indonesia (as defined in GR 1/2019), if such account has not existed, or move such account onshore, if such account already exists. Under GR 1/2019, an "escrow account" is defined as an account opened to collect particular funds from which a withdrawal can only be made based on special requirements in accordance with a written agreement between a depositor and a party with an interest over such escrow account. The supervision of such escrow accounts is conducted by the OJK.

On July 1, 2019, the Minister of Finance of Indonesia enacted Regulation of the Minister of Finance Number 98/PMK.04/2019 of 2019 on Tariffs for Administrative Sanctions in the Form of Fines and Procedures for the Imposition, Collection and Payment of Administrative Sanctions in the Form of Fines for Violations of the Provisions on Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or Management Activities ("PMK 98/2019"). PMK 98/2019 sets out the following administrative sanctions: (i) in the case that an exporter fails to deposit the DHE

SDA in a special account maintained in a Foreign Exchange Bank in Indonesia (as defined in PMK 98/2019), such an exporter will be imposed with fines in the amount of 0.5% of the value of the DHE SDA which has not been deposited in such special account; (ii) in the case that an Exporter utilizes the DHE SDA deposited in the special account for purposes other than for the payments of: (a) export duties and other levies that apply to exports; (b) loan repayments; (c) importation activities; (d) profits or dividends; and/or (e) other purposes as regulated under Article 8 of Law No. 25 of 2007 on Investment, such an exporter will be imposed with fines in the amount of 0.25% of the value of the DHE SDA utilized for such other purposes; and (iii) for an exporter who fails to set up an escrow account (which is an account used to make the payments described previously in point (ii)) or fails to move such account onshore, to a Foreign Exchange Bank in Indonesia (as defined in PMK 98/2019), such an exporter will be imposed with an administrative sanction in the form of a postponement of provision of export customs services.

BUSINESS

Unless otherwise stated, the operational summaries and data in this section (including relating to our natural gas transmission and distribution, LNG production, upstream and downstream oil and gas businesses and strategies, proved plus probable oil and gas reserves, exploratory and development wells, oil and gas fields/blocks and upstream oil and gas production and distribution) exclude information concerning and data of PGN, our 56.96% subsidiary acquired in April 2018, which is listed on the Indonesia Stock Exchange under the ticker symbol "PGAS."

You should read the following section in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations — Our Subsidiary, PGN; PGN Acquisition and Related Restatement of Our Financial Statements" and the accompanying notes thereto included elsewhere in the Offering Memorandum.

Overview

We are a fully integrated national oil, gas and geothermal company, wholly owned by the Government and headquartered in Jakarta, Indonesia. We have an operating history of more than 60 years. We were established on December 10, 1957 and became an Indonesian limited liability company in 2003.

We are engaged in a broad spectrum of upstream and downstream oil, gas, geothermal, petrochemical and other energy operations. Our lines of business are organized into upstream and downstream sectors in accordance with Indonesian oil, gas and geothermal regulations. In the upstream sector, we engage in the exploration (the search for oil, gas and geothermal energy), development (the drilling and bringing into production of wells in addition to the discovery wells in a field) and production and supply of crude oil, natural gas and geothermal energy in Indonesia and internationally. In the downstream sector, we carry out refining, marketing, distribution and trading of crude oil, natural gas, refined fuel products and petrochemical and other non-fuel products such as green coke, including products for retail, industrial and aviation uses. We are also mandated by the Government to distribute subsidized fuel, LPG and CNG in Indonesia and to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program and to encourage the use of CNG as an alternative fuel.

As of September 30, 2019, our total net proved oil and gas reserves were an estimated 2,053.8 mmboe and our total net proved plus probable oil and gas reserves were an estimated 2,665.6 mmboe. We have the largest base of oil and gas "commercial reserves" in Indonesia as of March 31, 2019, based on Wood Mackenzie's procedures for reserves categorization. We are also the largest exploration and production player in Indonesia, hold more total blocks and active blocks than any other entity in Indonesia, and have the largest net acreage of all oil and gas companies in Indonesia, according to Wood Mackenzie.

We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 894.0 mboe/d in the nine months ended September 30, 2019. We also have significant geothermal resources and an extensive distribution network of gas pipelines. Our geothermal installed capacity was 617 MW as of September 30, 2019. We have a portfolio of six refineries with total refining capacity of 1,031.0 mbbls/d and significant downstream assets and infrastructure, including fuel stations, fuel terminals, LPG filling plants, aviation fuel depots, lube oil blending plants, tankers and CNG refueling stations.

For the nine months ended September 30, 2018 and 2019, we had total sales and other operating revenue of US$43,187.7 million and US$39,174.8 million, respectively, and profit after the effect of

merging entity's income adjustment of US$2,689.2 million and US$775.9 million, respectively. For a detailed discussion of our results of operations for these periods, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations" in this Supplemental Offering Memorandum.

Pertamina Upstream Business

Overview

Our domestic upstream business manages the exploration, development and production of crude oil and natural gas, the transmission of our natural gas, our geothermal operations and our technology services and drilling services. In addition, we manage the exploration, development and production of crude oil and natural gas outside Indonesia. The various subsidiaries and joint ventures described below operate our upstream business and are overseen by our Upstream Directorate, which is a business unit of our Company.

PHE, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas in certain of our partially-owned assets in Indonesia and internationally, which includes 49 exploration and production blocks in Indonesia (consisting of 51 working areas), one block in Malaysia and one block in Vietnam. In the nine months ended September 30, 2019, PHE's operations contributed 78.7 mbbls/d and 803.4 mmcf/d to our total crude oil and natural gas production. PHE's domestic work areas comprise 30 own-operated fields, seven unitization fields, 19 partnership arrangements (including 15 unconventional oil and gas partnership arrangements), four JOB PSCs and seven unitization agreements.

PEP, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas from our wholly owned oil and gas fields, which is comprised of five assets covering 21 production fields, nine development projects, six unitization fields and 31 partnership contracts across Sumatra, Java, Kalimantan, Sulawesi and Papua (comprising of 7 TACs and 24 joint operations, or *kerja sama operasi* ("KSOs")). In total, PEP's production fields have an aggregate working area of 113,629.8 km^2. In the nine months ended September 30, 2019, PEP's operations contributed 82.4 mbbls/d and 956.2 mmcf/d to our total crude oil and natural gas production.

PEPC, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas in our Cepu block in partnership with subsidiaries of ExxonMobil Corp. and Regional Owned Enterprises. The Cepu block contains one production field and two development projects in an aggregate working area of 919.2 km^2 across Bojonegoro and Tuban in East Java and Blora in Central Java. In the nine months ended September 30, 2019, PEPC's operations contributed 98.5 mbbls/d and 25.8 mmcf/d to our total crude oil and natural gas production.

PT Pertamina EP Cepu ADK ("PEPC ADK"), our wholly-owned subsidiary, manages the exploration of crude oil and natural gas in our Alas Dara Kemuning ("ADK") block in Central Java. The ADK field has a working area of approximately 23.7 km^2.

PIEP manages 11 of our international oil and gas operating assets. These assets are in various stages of exploration, development and production, and are located in Algeria, Tanzania and Gabon, Namibia, Nigeria in Africa; Malaysia and Iraq in Asia; Canada, Colombia in the Americas; and France and Italy in Europe. In the nine months ended September 30, 2019, PIEP's operations contributed 99.1 mbbls/d and 262.6 mmcf/d to our total crude oil and natural gas production.

PT Pertamina Hulu Indonesia ("PHI"), our wholly-owned subsidiary, is an operation holding company that controls and manages the assets and upstream business operations of Pertamina within the country of the terminated working areas and gas blocks that the Government granted to us, except for terminated work areas previously managed by our affiliates. PHI is the parent of PT Pertamina Hulu Mahakam ("PHM"), which manages the Mahakam Block. In the nine months ended September 30, 2019, PHM completed drilling of 90 wells. In the nine months ended September 30, 2019, PHI's operations contributed 51.2 mbbls/d and 757.5 mmcf/d to our total crude oil and natural gas production.

PT Pertamina Geothermal Energy ("PGE"), our wholly-owned subsidiary, manages our geothermal operations. As of September 30, 2019, PGE managed 14 geothermal concessions in Indonesia, covering an area of 20,425 km^2. Of our 10 own-operated working areas, six were in the production stage and four were in the exploration or development stage. Of our five working areas jointly operated through JOCs, four were in the production stage and one was in the development stage. We have 1,365 MW of estimated proved and probable reserves in our geothermal concessions. The total installed capacity of PGE-owned operations is 617 MW as of September 30, 2019, consisting of 235 MW in the Kamojang area, 120 MW in the Lahendong and Tompasso area, 220 MW in the Ulubelu area, 12 MW in the Sibayak area, 30 MW in the Karaha Bodas area and 55 MW in the Lumut Balai area. In the nine months ended September 30, 2019, our geothermal projects produced 24,472 mt of steam or 3,220 GWh in electricity equivalent.

PGE continues to undertake geothermal exploration and development activities in all managed areas, which are Seulawah, Sungai Penuh, Hulu Lais, Lumut Balai, Karaha Bodas and Gunung Lawu. See "— Geothermal" for more information on our geothermal operations.

Our upstream business also includes support businesses, including those operated by our wholly-owned subsidiaries, PT Pertamina Drilling Services Indonesia ("PDSI") and PT Elnusa Tbk ("Elnusa"). PDSI provides drilling services to support our oil and gas and geothermal development activities, while Elnusa provides integrated upstream oil and gas services and downstream oil and gas services.

As of September 30, 2019, our estimated total net proved oil and gas reserves were 2,053.8 mmboe, consisting of 1,013.7 mmbbls of oil and 6,026.1 bcf of gas, and our total net proved plus probable oil and gas reserves were 2,665.6 mmboe, consisting of 1,327.3 mmbbls of oil and 7,754.3 bcf of gas. In the nine months ended September 30, 2019, we had total average daily net oil and gas production of 894.0 mboe/d, consisting of 409.9 mbbls/d of oil and 2,805.1 mmcf/d of gas.

See "— Reserves" and "— Production" for more information on our oil and gas reserves and production, respectively.

Upstream Strategy

In order to enhance our upstream portfolio through risk diversification and technology sharing with strategic partners, and consistent with our aim to grow our upstream business by assuming sole or joint management of domestic oil and gas blocks as existing operating contracts expire, we aim to assign part of our working interests in certain blocks, including in relation to the Rokan Block, the Mahakam Block and the Sanga Sanga Block, to strategic third parties over the course of 2020.

Oil and Gas

Our upstream oil and gas operations are conducted through our own operations as well as through joint operating arrangements. We have an interest in 81 blocks worldwide, of which 28 blocks are

located in Algeria, Iraq, Malaysia, Tanzania, Gabon, Nigeria, Canada, Colombia, Namibia, France, Italy and Vietnam, and are operated through partners or third parties via joint operating arrangements. The remaining 53 blocks are located in the Sumatra, Java, Kalimantan, Sulawesi and Papua regions of Indonesia. We own-operate 46 of our blocks in Indonesia, while the remaining 35 of our blocks in Indonesia are operated through partners or third parties via joint operating arrangements.

Oil and Gas Reserves

As of September 30, 2019, our total estimated net proved oil and gas reserves were 2,053.8 mmboe, consisting of 1,013.7 mmbbls of oil and 6,026.1 bcf of gas, and our estimated total net proved plus probable oil and gas reserves were 2,665.6 mmboe, consisting of 1,327.3 mmbbls of oil and 7,754.3 bcf of gas.

The following table sets forth our estimated aggregate net proved and probable reserves as at the dates indicated and the factors which, over the periods indicated, reduced or increased our estimated aggregate net proved and probable reserves.

	Crude Oil (mmbbls)	Natural Gas (bcf)	Combined (mmboe)
2019 (As of September 30, 2019)[1]			
Total net proved plus probable reserves (as of January 1, 2019)	1,362.8	7,825.4	2,713.4
Revisions of previous estimates[2]	(17.4)	(0.7)	17.5
Extensions and discoveries[3]	71.8	268.3	118.1
Acquisitions and divestments	13.4	267.8	59.6
Production	(103.3)	(606.5)	(208.0)
Total net proved plus probable reserves (As of September 30, 2019)	**1,327.3**	**7,754.3**	**2,665.6**
Probable reserves	313.6	1,728.2	611.9
Total net proved reserves (As of September 30, 2019)	**1,013.7**	**6,026.1**	**2,053.8**

Note:

(1) Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, estimates of our oil and gas reserves as of September 30, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

(2) Revisions of previous estimates represent changes over the course of the periods indicated in previous estimates of reserves, either up or down, resulting from new information normally obtained from development drilling and production activities.

(3) Extensions and discoveries represent additions to proved plus probable reserves that result from (i) extensions of previously discovered fields demonstrated to exist subsequent to the original discovery, and (ii) the discovery of reserves in new fields or new reservoirs in old fields, in each case over the course of the periods indicated.

The following table sets forth our estimated net proved and probable reserves by region as of September 30, 2019.

	Crude Oil (mmbbls)	Natural Gas (bcf)	Combined (mmboe)
Sumatra	204.3	2,129.8	571.9
Java	620.6	3,225.4	1,177.3
East Indonesia (Kalimantan, Sulawesi and Papua)	131.6	1,848.1	450.6
Overseas	370.8	551.0	465.9
Total	**1,327.3**	**7,754.3**	**2,665.6**

As of September 30, 2019, our net proved plus probable reserves have an estimated average life of 10.0 years and our net proved reserves have an estimated average life of 7.7 years. For more information about reserves estimates, see "Presentation of Financial and Other Data — Oil and Gas Reserves."

Oil and Gas Exploration and Development

In the nine month period ended September 30, 2019, our success rates for our exploration well drilling was 66.7%. The following table sets forth the number of exploratory and development wells completed by us on our properties as at the dates indicated.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
Gross exploratory wells drilled[1]	10	9
Crude oil	5	1
Natural gas	1	1
Crude oil and natural gas	1	4
Dry[2]	3	3
Gross development wells drilled[1]	116	223
Crude oil	48	99
Natural gas	29	79
Crude oil and natural gas	39	45
Dry[2]	0	0

Notes:

(1) "Gross" wells refer to all exploratory or development wells, as the case may be, without deducting interests held by others.

(2) "Dry" wells are exploratory or development wells, as the case may be, incapable of producing oil or gas in sufficient quantities to justify completion of exploration as an oil or gas well.

The following table sets forth the number of exploratory and development wells completed by us on our properties by region as at the dates indicated.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
Gross exploratory wells drilled[1]	10	9
Productive	7	6
Sumatra	2	1
Java	4	2
East Indonesia (Kalimantan, Sulawesi and Papua)	1	1
Overseas	0	2
Dry[2]	3	3
Sumatra	1	2
Java	1	0
East Indonesia (Kalimantan, Sulawesi and Papua)	1	1
Overseas	0	0
Gross development wells drilled[1]	116	223
Sumatra	19	48
Java	18	11
East Indonesia (Kalimantan, Sulawesi and Papua)	66	139
Overseas	13	25

Notes:

(1) "Gross" wells refer to all exploratory or development wells, as the case may be, without deducting interests held by others.

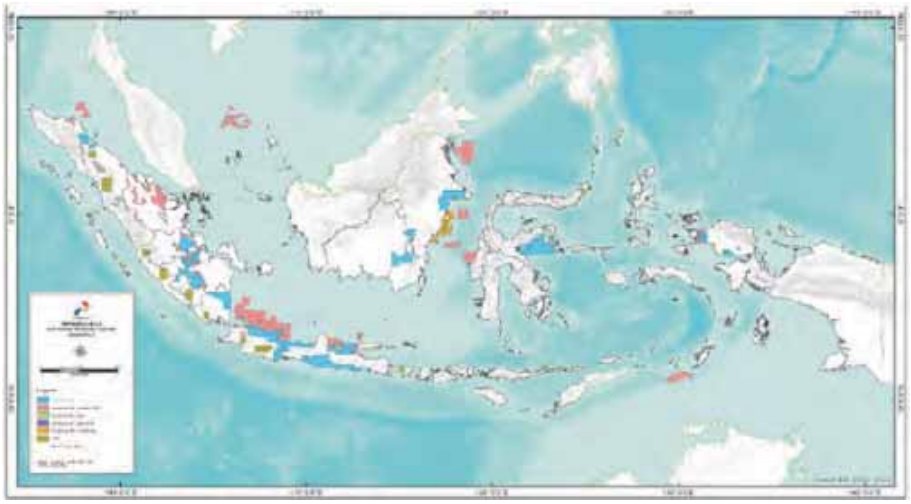
(2) "Dry" wells are exploratory or development wells, as the case may be, incapable of producing oil or gas in sufficient quantities to justify completion of exploration as an oil or gas well.

As of September 30, 2019, we had approximately 34,293 km^2 of undeveloped acreage for future exploration and development.

Exploration and development plans. We have set a target to drill more than 319 development wells by the end of 2020. Through PHE, we have entered into PSCs for the exploration and development of coal bed methane in 15 working areas in Sumatera and Kalimantan working area with contract terms of 30 years having end dates beyond 2038. PHE directly operates six of these working areas, with the remaining nine operated by third parties.

Drilling operations. Our oil and gas and geothermal exploration and development activities require extensive drilling expertise and support. Our wholly owned subsidiaries, PDSI and Elnusa, provide land drilling services, integrated drilling project management and drilling tools to support our onshore drilling activities. In total, we have a fleet of 41 onshore drilling rigs located across Indonesia.

The following map illustrates our domestic upstream operations as of September 30, 2019.



The following tables set forth certain information regarding our material upstream operations as of September 30, 2019, other than PEPC ADK's Alas Dara Kemuning block, which is in the exploration stage.

PHE

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Corridor	10.0	December 20, 2003 to December 19, 2023	Conoco Philips (Grissik) LTD (54%) (operator), Talisman (36%)	1.1	194.5	0.71	104.88
CPP	50.0	August 9, 2002 to August 8, 2022	PT Bumi Siak Pusako (50.0%) (operator BOB Pertamina Bumi Siak Pusako)	9.5	—	5.21	0

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Jabung	14.2	February 27,1993 to February 26, 2023	Petrochina (Jabung) LTD (42.9%) (operator), Petronas (42.9%)	9.0	74.2	2.13	38.58
Jambi Merang	100.0	February 10, 2019 to February 9, 2039	—	10.6	250.3	2.99	60.52
Offshore North West Java	90.0	January 19, 2017 to January 18, 2037	PT MUJ-BUMD (10.0%)	320.7	943.8	25.28	88.04
Offshore South East Sumatera	100.0	September 6, 2018 to September 5, 2038	—	40.9	143.4	27.9	110.76
Ogan Komering	100.0	May 19, 2018 to May 18, 2038	—	2.5	7.7	1.29	5.03
Senoro Toili	50.0	December 4, 1997 to December 3, 2027	PT Medco E&P Tomori Sulawesi (30.0%), Tomori E&P Ltd. (20.0%)	8.2	507.5	3.66	151.19
Tuban East Java	100.0	May 20, 2018 to May 19, 2038	—	1.4	2.7	1.11	2.83
West Madura Offshore	80.0	May 7, 2011 to May 6, 2031	Kodeco Energy Co LTD (10.0%), Mandiri Madura Barat (10%)	19.0	160.0	3.46	103.22
Siak	100.0	May 27, 2014 to May 26, 2034	—	6.8	—	1.64	—
North Sumatera B	100.0	October 6, 1998 to October 4, 2018 (extended until 2 x 6 months and 45 days)	—	1.5	24.0	—	—
North Sumatera Offshore	100.0	October 17, 2018 to October 16, 2038	—	0.2	95.5	0.9	104.89
Raja Tempirai	100.0	July 6, 2019 to July 5, 2039	—	1.8	—	0.37	—
Simenggaris	37.5	February 24, 1998 to February 23, 2028	Medco Simenggaris Pty Ltd (41.5%), Salamander Energy Ltd (21%)	—	8.3	—	0.01
Kampar	100.0	January 1, 2016 to December 31, 2036	—	2.3	—	1.31	—
Kakap	10.0	March 22, 2005 to March 21, 2028	Star Energy (Kakap) Ltd (56.25%), Premier Oil Kakap BV (18.75%), and Singapore Petroleum Co. Ltd (15%)	1.0	16.9	0.22	2.82
Blok A (Natuna Sea)	11.5	October 16, 2009 to October 15, 2029	Premier Oil Natuna Sea Ltd (28.7%), Kufpec Indonesia (Natuna) B.V. (33.33%) and Natuna I B.V. (15%)	1.0	73.2	0.12	26.93

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Randugunting	100.0	August 9, 2007 to August 8, 2037	—	**	**	**	**
Abar	100.0	May 22, 2015 to May 21, 2045	—	**	**	**	**
Anggursi	100.0	May 22, 2015 to May 21, 2045	—	**	**	**	**
Nunukan	64.5	December 12, 2004 to December 11, 2034	Videocon Indonesia Nunukan (23%), BPRL Ventures Indonesia B. V. (12.5%)	**	**	**	**
Ambalat	33.75	September 27, 1999 to September 26, 2029	Eni Ambalat Ltd (66.25%)	**	**	**	**
East Ambalat	100.0	May 24, 2016 to May 23, 2036	—	**	**	**	**
Makassar Strait	10.0	January 26, 1990 to January 25, 2020	Chevron Makassar Strait (72.0%), Sinopec Tiptop (18.0%)	**	**	**	**
Maratua	100.0	February 18, 2018 to February 17, 2038	—	**	**	**	**
Bukat	33.75	February 24, 1998 to February 23, 2028	Eni Bukat Ltd (66.25%)	**	**	**	**
East Sepinggan	15.0	July 20, 2012 to July 20, 2042	Eni East Sepinggan Ltd (85%)	—	122.1	**	**
Babar Selaru	15.0	November 21, 2011 to November 20, 2041	Inpex Babar Selaru (85%)	**	**	**	**
Tanjung Enim	27.5	August 4, 2009 to August 3, 2039	PT Bukit Asam Metana Enim (27.5%), Dart Energy (Tanjung Enim) Pte Ltd (45%)	**	**	**	**
Muara Enim	60.0	November 30, 2009 to November 29, 2039	PT Trisula CBM Energy (40%)	**	**	**	**
Muara Enim I	65.0	December 3, 2010 to December 2, 2040	PT Indo Gas Methan (35%)	**	**	**	**
Muara Enim II	40.0	April 1, 2011 to March 31, 2041	PT Metana Enim Energi (30%) and Indo CBM Sumbagsel 2 Pte Ltd (30%)	**	**	**	**
Muara Enim III	40.0	April 1, 2011 to March 31, 2041	PT Metana Enim Energi (30%) and Indo CBM Sumbagsel 2 Pte Ltd (30%)	**	**	**	**
Sangatta I	52.0	November 13, 2008 to November 12, 2038	Sangatta West CBM Inc (48%)	**	**	**	**
Sangatta II	40.0	May 5, 2009 to May 4, 2039	PT Visi Multi Artha (60%)	**	**	**	**

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
MNK Sumbagut	100.0	May 15, 2013 to May 14, 2043	—	**	**	**	**
MNK Sakakemang	50.0	May 22, 2015 to May 21, 2045	Bukit Energy Resources Sakakemang Deep Pte Ltd (50%)	**	**	**	**

Note:

** Not applicable; the block is in the development or exploration stage.

From April 2020 until April 2040, we will have a 30.0% working interest in the Salawati block, with the other 70.0% being held by Petrogas Island Ltd. We previously held a 50.0% working in interest in the Salawati block and, as of September 30, 2019, its estimated net proved and probable reserves were 3.9 mmbbls and 2.0 bcf for oil and gas, respectively, and the average net annual production is 751.99 bbls/d and 2.22 mmcf/d for oil and gas, respectively.

From October 2020 until October 2040, we will have a 30.0% working interest in the Kepala Burung block, with the other 70.0% being held by Petrogas Basin Ltd. We previously held a 10.0% working interest in the Kepala Burung block and, as of September 30, 2019, its estimated net proved and probable reserves were 0.8 mmbbls and 5.8 bcf for oil and gas, respectively.

PT Pertamina Hulu Rokan

Pursuant to a PSC, we will have a 100% working interest in, and manage the working area of, Rokan from August 2021 until August 2041. We are currently in discussions with the existing operator, PT Chevron Pacific Indonesia, about future plans and activities to achieve a productive and efficient handover, and we will commence work in 2020 relating to production and exploration in preparation for 2021.

PEP

Region	Working Interest (%)	Contract Term	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
			Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Sumatra	100.0	September 2005 to September 2035	156.9	1,393.5	28.862	478
Java	100.0	September 2005 to September 2035	84.8	1,167.3	10.987	297
Eastern Indonesia (Kalimantan, Sulawesi and Papua)	100.0	September 2005 to September 2035	89.4	504.8	41.701	194

PEPC

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Cepu	45.0	September 17, 2005 to September 16, 2035	Ampolex (Cepu) Pte Ltd. (24.5%), ExxonMobil Cepu Limited (20.5%) (operator), PT Sarana Patra Hulu Cepu (1.1%), PT Petrogas Jatim Utama Cendana (2.2%), PT Asri Dharma Sejahtera (4.5%), PT Blora Patragas Hulu (2.2%)	153.9	808.2	93.62	20.62

PHI

Block/Field	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Mahakam Block	90.0	January 1, 2018 to December 31, 2037	PT Migas Mandiri Pratama Kutai Mahakam	17.9	609.0	30.42	714.6
Sanga Sanga Block	100.0	August 8, 2018 to August 7, 2038		5.7	54.0	7.51	81.6
East Kalimantan and Attaka Block	100.0	October 25, 2018 to October 24, 2038		5.7	34.5	9.54	53.1
West Ganal	30	Jan 26, 2020 to Jan 25, 2040	ENI 40%, Neptune Energy 30%	*	*	*	*

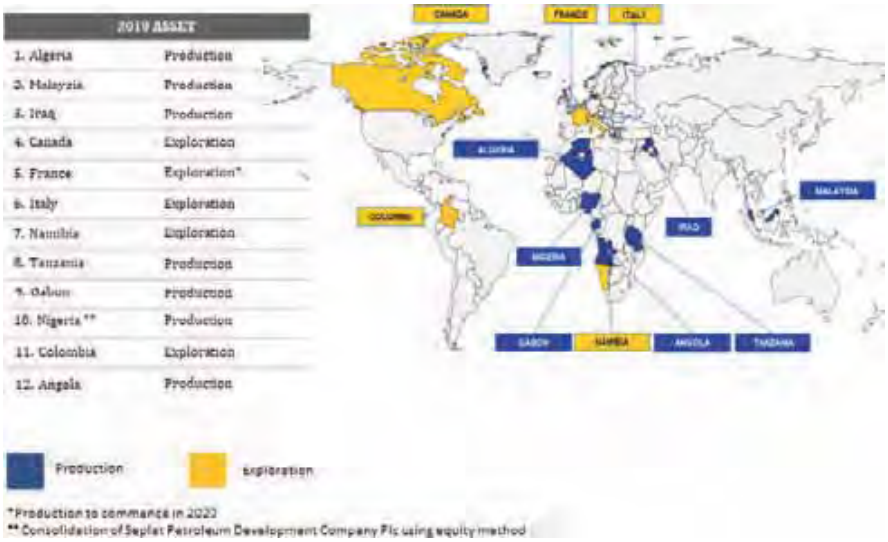
Note:

* Information not available.

Description of International Oil and Gas Properties

Our oil and gas activities outside of Indonesia are primarily operated by our joint venture partners. Of our 22 international assets, 6 are currently in commercial production.

The following map illustrates our international upstream operations as of September 30, 2019.



The following tables set forth certain information regarding our upstream international operations as of September 30, 2019, excluding blocks held by M&P for which no information is available.

				Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
Block/Field	**Working Interest (%)**	**Contract Term**	**Partners**	**Oil (mmbbls)**	**Gas (bcf)**	**Oil (mbbls/d)**	**Gas (mmcf/d)**
Algeria							
Block 405a, Menzel Lejmat North (MLN) Field	65.0	December 20, 2000 to December 19, 2025	Talisman (Algeria) B.V. (35.0%)	35.8	—	23	168
Block 405a, El Merk (EMK) Field	16.9	July 2005 to July 2030	Talisman (Algeria) B.V. (9.1%), Sonatrach (37.7%), Anadarko Algeria Company LLC (18.1%), Eni Oil Algeria Ltd. (9.1%), Maersk Olie Algeriet AS (9.1%)	24.5	—	*	*
Block 405a, Ourhoud Field	3.7	December 6, 1997 to December 5, 2022	Talisman (Algeria) B.V (1.9%), Sonatrach (37.1%), Anadarko Algeria Company LLC (10.2%), Eni (5.08%), Maersk Olie Algeriet AS (5.08%), Compania Española Petroleos SA (37.1%)	2.7	—	*	*
Gabon							
Ezanga	80.0	January 1, 2014 to December 31, 2034	The Gabonese Republic (12.5%), Tullow (7.5%)	—	—	—	—
Iraq							
Block West Qurna I	10.0	January 25, 2010 to January 24, 2045	ExxonMobil Iraq Limited (32.7%), Shell Iraq B.V. (19.6%), PetroChina International Iraq FZE (32.7%), Oil Exploration Company of the Iraqi Ministry of Oil (5.0%)	141.8	—	45	—
Malaysia							
Block H, Sabah	24.0	March 19, 2007 to March 18, 2045	PTT Exploration and Production (“PTTEP”) (56.0%), Petronas (20%)	38.4	328.1	17	91
Block K, Sabah	24.0	January 27, 1999 to January 26, 2037	PTTEP (56.0%), Petronas (20%)	26.0	18.8	*	*

Block/Field	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Production (Nine Month Period Ended September 30, 2019)	
				Oil (mmbbls)	Gas (bcf)	Oil (mbbls/d)	Gas (mmcf/d)
Block SK 305, Sarawak	30.0	June 16, 2003 to June 15, 2032	Petronas Carigali Sdn. Bhd. (40.0%) PetroVietnam (30.0%)	—	—	*	*
Block SK309, Sarawak	25.5	January 27, 1999 to January 26, 2028	PTTEP (59.5%), Petronas (15%)	3.0	63.6	*	*
Block SK311, Sarawak	25.5	January 27, 1999 to January 26, 2028	PTTEP (59.5%), Petronas (15%)	9.3	37.8	*	*
Block SK314A, Sarawak	25.5	May 7, 2013 to May 6, 2040	PTTEP (59.5%), Petronas (15%)	—	—	*	*
Vietnam							
Vietnam Blok 10 and 11.1	10.0	January 8, 2002 to January 7, 2032	Petrovietnam Exploration Production Corporation Ltd (40%), Petronas Carigali Sdn. Bhd. (40%) Quad Energy S.A. (10%)	—	—	—	—
Colombia							
Cor 15	20.0	*	*	—	—	—	—
Namibia							
Petroleum Exploration License-44	42.5	*	Azinam (42.5), National Petroleum Corporation of Namibia (8%), Livingstone Mining Resource Development (4%), Frontier Mineral Resources (3%)	—	—	—	—
Nigeria							
OML 4, 38, 41	45.0	June 1989 to October 2038	Nigerian Petroleum Development Company Ltd (55.0%)	—	—	—	—
OPL 283	40.0	October 2009 to October 2028	Pillar Oil (60.0%)	—	—	—	—
OML 53	40.0	June 1997 to June 2027	National Nigerian Petroleum Corporation (60.0%)	—	—	—	—
OML 55	22.0	June 1997 to June 2027	Belema Oil (*), National Nigerian Petroleum Corporation (*)	—	—	—	—
Tanzania							
Mnazi Bay	48.1	October 26, 2006 to October 25, 2031	Wentworth (31.9%), TPDC (20.0%)	—	—	—	—
Canada							
Alberta	25.0	*	*	—	—	—	—
Italy							
Fiume Tellaro	100.0	*	*	—	—	—	—
Venezuela* **							
Urdaneta West Field	40.0	2006 to 2026	Petróleos de Venezuela, S.A. (60.0%)	*	*	*	*

Notes:

* Information not available.

** Not applicable; the block is in the development or exploration stage.

*** M&P has no active operations in Venezuela.

Upstream Oil and Gas Production

Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 894.0 mboe/d in the nine months ended September 30, 2019. The following table sets forth our average oil and gas

production on a daily basis, our average realized sales prices per barrel of crude oil, average realized sales prices per thousand cubic feet of natural gas, lifting costs per barrel of crude oil and lifting costs per thousand cubic feet of natural gas produced for the period, indicated.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
Sumatra		
Crude oil (mbbls/d)	61.8	79.0
Natural gas (mmcf/d)	944.4	945.0
Total (mboe/d)	**224.8**	**242.1**
Java		
Crude oil (mbbls/d)	148.0	155.5
Natural gas (mmcf/d)	598.8	571.0
Total (mboe/d)	**251.4**	**254.1**
East Indonesia (Kalimantan, Sulewasi and Papua)		
Crude oil (mbbls/d)	72.1	76.2
Natural gas (mmcf/d)	1,214.9	1,026.5
Total (mboe/d)	**281.8**	**253.4**
International		
Crude oil (mbbls/d)	102.2	99.1
Natural gas (mmcf/d)	300.2	262.6
Total (mboe/d)	**154.0**	**144.4**
Total		
Crude oil (mbbls/d)	384.1	409.9
Natural gas (mmcf/d)	3,058.3	2,805.1
Total (mboe/d)	**911.9**	**894.0**
Average realized sales price of oil (US$ per bbl)	70.3	65.2
Average realized sales price of gas (US$ per mcf)	6.3	6.5
Operating costs of oil and gas (US$ per boe)	14.9	16.8

Upstream Oil and Gas Sales and Distribution

Crude Oil

Our policy is to maximize usage of our crude oil production as feedstock in our refineries. In the nine months ended September 30, 2019, 78.5% of the crude oil we produced was used as feedstock in our refineries. A portion of the crude oil which we produce is not of suitable quality for our refineries and we trade such crude oil in exchange for crude oil of suitable quality or sell it on the spot market or through a term contract. For the nine-month period ended September 30, 2019, 21.5% of our crude oil production was either traded or sold to third parties.

Gas

The following table sets forth our material gas sales agreements.

Block	Counterparty	Term	Pricing (US$/mmbtu)	Total Quantity (bbtu)	Daily Quantity (bbtu/d)	Take-or-Pay %
Sumatra						
Jambi Merang	PLN	February 10, 2019 – December 31, 2025	6.44[1]	109.8	40	85%
PEP[2]	Asrigita Prasarana	20 years from 2004	6.14	188,940	28.9	70%

Notes:

(1) For the first 12 months and further escalated by 3% for every 12 months thereafter.

(2) PEP has also entered into a contract with PGN South Sumatra-West Java for a period of 20 years from 2006 to provide 1,006,050,003,000 bbbtu of natural gas at a price of US$5.33/mmbtu.

PGN's Upstream Business

As of September 30, 2019, Saka holds interests in eleven oil and gas blocks in Indonesia, of which five are in the production stage and six are in the exploration phase.

Block	Ownership (%)	Status
Ketapang PSC	20	Production
South Sesulu PSC	100	Exploration
Bangkanai PSC	30	Production
West Bangkanai PSC	30	Exploration
Pangkah PSC	100	Exploration
Muriah PSC	20	Production
Fasken	36	Production
Muara Bakau PSC	11.6	Production
Wokam II PSC	100	Exploration
Pekawai PSC(1)	100	Exploration
West Yamdena PSC(1)	100	Exploration

Note:

(1) Contract with Government signed in 2018.

In the nine months ended September 30, 2019 and 2018, Saka and its subsidiaries produced total lifting of 8.09 mmboe/d and 11.07 mmboe/d, respectively, comprising 1,449,360 bbls and 2,247,263 bbls of lifting oil, respectively, 23,261 bbtu and 33,470 bbtu of gas, respectively, 21,095 mt and 25,169 mt of LPG, respectively, and 13,457 bbtu and 16,013 bbtu of LNG, respectively. The following table sets forth select information regarding Saka's lifting and sales of oil, gas, LPG and LNG. This information has been derived from publicly available sources and rounded.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
Crude oil (in bbls)	2,247,263	1,149,360
Natural gas (in mmbtu)	33,470,000	23,261,000
LPG (in mt)	25,169	21,095
LNG (in mmbtu)	16,013,000	13,457,000

PGN's exploration and production of oil and gas segment generated revenues of US$292.1 million in the nine months ended September 30, 2019, which accounted for 10.0% of PGN's net revenues in the nine months ended September 30, 2019. Revenues were primarily driven by the Muara Bakau Block that started production in June 2017 and the Sanga Sanga block that was in full production for the year.

Geothermal

As of September 30, 2019, we had 14 geothermal concessions in Indonesia, covering an area of 20,425 km^2. Of our ten own-operated working areas, six were in the production stage and four were in the exploration or development stage. Of our five working areas jointly operated through JOCs, four were in the production stage and one was in the development stage.

We had a total current installed capacity for power generation in 14 geothermal working areas of 617 MW as of September 30, 2019, which we intend to increase to 672 MW by the end of 2020.

Geothermal Reserves, Capacity and Other Operating Data

Our estimated proved plus probable geothermal reserves was 1,365 MW as of September 30, 2019. The following table sets forth certain key information relating to our own-operated geothermal areas. As of September 30, 2019, Pertamina holds a 100.0% working interest in each of the projects below, except for our Seulawah project, in which we hold 75.0%.

	Estimated Proved and Probable Reserves (MW)	Current Installed Capacity (MW)	Capacity under Development (MW)
Sumatra			
Sibayak	40	12	—
Ulubelu	225	220	—
Lumut Balai	250	55	55
Sungai Penuh	65	0	55
Hulu Lais	250	0	110
Seulawah	0*		0
Java			
Kamojang	235	235	0
Karaha Bodas	50	30	0
Gunung Lawu	0*		0
East Indonesia			
Lahendong & Tompasso	220	120	0
Total	**1,365**	**672**	**220**

Note:

* This geothermal area is in the exploration or development phase.

The table below sets forth certain key information relating to our geothermal areas that are operated under JOCs that are operational as of September 30, 2019.

Jointly Operated Areas	Ownership (%)	Contractor(s)	Current Production Capacity (MW)	Share in Capacity (MW)/ Net Operating Income (%)
Gunung Salak, JOC Cibeureum Parabakti	100.0	UNOCAL Geothermal of Indonesia Ltd, Daya Bumi Salak Pratama Ltd	377	4.0
JOC Darajat	100.0	Chevron Darajat Limited, Texaco Darajat Limited, PT Darajat Geothermal Indonesia	271	2.7
JOC Pengalengan	100.0	Star Energy Geothermal Wayang Windu Limited	227	4.0
JOC Sarulla	100.0	PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Ltd, Orsarulla Inc., Kyuden Sarulla Pte., Ltd.	330	4.0
Tabanan	100.0	Bali Energy Limited	0	4.0

Geothermal Production

The following table sets forth our aggregate geothermal production for the periods indicated.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
Total annual production		
Steam (mt)	23,242	24,472
(expressed in electricity equivalent) (GWh)	3,138	3,220
Average daily production		
Steam (mt)	85.1	89.6
(expressed in electricity equivalent) (GWh)	11.5	11.8

Pertamina Downstream Business

Overview

Our downstream business includes several business lines: oil and gas refining, marketing, trading and shipping of crude oil, refined oil and gas products, distributing subsidized fuel products and operating certain LNG assets on the Government's behalf. We categorize our refined oil and gas products as (i) retail oil-based fuel, such as motor gasoline and diesel, (ii) special fuel products, such as aviation gasoline, (iii) non-fuel and petrochemical products, such as green coke and lube-base oil, and (iv) gas-based fuel, such as LPG.

We are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia. Our total production capacity of 1,031.0 mbbls/d in 2018 comprised nearly all of Indonesia's total refining capacity of 1.1 mmbbls/d, based on Wood Mackenzie data. We are also the largest oil and gas refiner in Southeast Asia region in terms of refining capacity, according to Wood Mackenzie. As of September 30, 2019, we had six refineries that have a total production capacity of approximately 1,031.0 mbbls/d and an average NCI of 6.0. In addition, as of September 30, 2019, we held a 48.6% non-controlling ownership interest in the PT Trans-Pacific Petrochemical Indotama ("TPPI") petrochemical refinery. We have subsequently acquired a majority beneficial ownership interest in TPPI, which will be reflected in our consolidated financial statements for the year ended December 31, 2019.

Annual fuel production, comprised of retail oil-based fuel, special fuel products and gas-based fuel, reached 195.1 mmbbls for the nine-month period ended September 30, 2019. Non-fuel and petrochemical production reached 20.7 mmbbls for the nine-month period ended September 30, 2019. See "— Refining" for more information on our refining business.

We hold significant interests in the downstream infrastructure and distribution networks in Indonesia, which are comprised of pipelines, fuel stations and depots, and shipping vessels.

As of September 30, 2019, we owned 117 fuel terminals, 22 LPG terminals and depots, 6,878 Pertamina-branded retail fuel filling stations, 647 fuel gas filling stations, 68 aviation fuel depots, 193 harbors and Terminal Khusus Untuk Kepentingan Sendiri and three lube oil blending plants and operated 262 tankers.

We believe that because of our extensive distribution infrastructure and assets in Indonesia, we have been granted the PSO mandate by the Government to produce, supply and distribute the majority of subsidized fuel in Indonesia. This PSO mandate requires us to distribute fuel at subsidized rates fixed by the Government. We are subsequently reimbursed by the Government for our costs in accordance with a prescribed formula. See "— PSO" for more information on our PSO mandate.

To optimize the margins from our refined products, we also further refine low sulfur waxy residual fuel oil and naphtha, which are intermediate products from the refining process.

Downstream Strategy

For the nine months ended September 30, 2019, our actual capital expenditures for our downstream segment was US$572.0 million.

Oil and Gas Refining

The following table presents our total refinery capacity, intake and production for the periods indicated.

	For the Years Ended December 31,			For the Nine-Month Periods Ended September 30,	
	2016	2017	2018	2018	2019
Capacity					
Refining capacity[1] (mbbls/d)	1,031.0	1,031.0	1,031.0	1,031.0	1,031.0
Average NCI	5.7	5.7	6.0	6.0	6.4
Average utilization rate[2] (%)	77.4	79.0	83.1	82.6	81.6
Annual intake					
Produced crude oil (mmbbls)	160.0	179.8	200.0	178.0	175.2
Imported crude oil (mmbbls)	134.3	117.6	112.9	54.5	54.4
High octane motor gas import (mmbbls)	0.2	—	0.4	0.4	—
Natural gas (mmbbls)	1.8	1.6	1.7	1.3	1.2
Others (mmbbls)	2.3	4.2	2.2	2.4	11.7
Annual production					
Fuel (mmbbls)	238.0	246.6	264.9	197.1	195.1
Non-fuel and petrochemicals (mmbbls)	17.7	28.7	27.5	20.1	20.7
Others (mmbbls)	31.0	13.9	9.6	7.5	14.9
Average daily production					
Fuel (mbbls/d)	650.4	675.7	725.7	721.9	714.7
Non-fuel and petrochemicals (mmbbls/d)	48.3	78.6	75.3	75.6	75.9
Others (mmbls)	84.8	38.0	26.2	27.5	54.7

Notes:

(1) Based on design capacity.

(2) Based on processing capacity.

See "— Downstream Products" for more information on the products produced from our refineries.

Refining Facilities

In the nine-month period ended September 30, 2019, the average utilization rate of the primary processing capacity of our refineries was 81.6%. As of September 30, 2019, RU IV Cilacap's NCI improved to 7.4.

The table below sets forth our refinery portfolio and planned key expansion and upgrading activities as of September 30, 2019.

Fuel

Refinery	Current Design Capacity (mbbls/d)	NCI	Key Expansion and Upgrade Details and Target Completion Dates
RU II Dumai	170	7.5	● Develop the engineering package of the Calciner Project, which consists of the construction of a coke factory that will process 300kTA Green Petroleum Coke ("GPC") and an additional 100 kTA GPC imports into 300 kTA of anode grade Calcinated Petroleum Coke ("CPC") ● Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater ● Open access for crude oil receiving facilities
RU III Plaju	118	3.1	● Open access for crude oil receiving facilities ● Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater
RU IV Cilacap	348	6.3	● Change the reconfiguration of the naptha processing complex RU IV Cilacap to improve the quality of fuel products form RON 88 to RON 92 ● Increase the flexibility of processing crude oil from 0.1% sulfur content to 2.0% ● Increase the operational processing capacity up to 1.1 times from the existing capacity ● Improve product quality from EURO II standards to Euro V standards ● Improve the refinery's NCI to 9.0
RU V Balikpapan	260	3.4	● Increase the flexibility of processing crude oil from 0.4% sulfur content to 2.0% by 2025 ● Increase the operational processing capacity up to 1.4 times from the existing capacity by 2023 ● Improve product quality from EURO II standards to Euro IV and Euro V standards by 2023 ● Improve the refinery's NCI to 9.0
RU VI Balongan	125	11.9	● Increase the flexibility of processing crude oil from 0.2% sulfur content to 1.0% ● Increase the operational processing capacity up to 1.3 times from the existing capacity ● Improve product quality from EURO II standards to Euro IV and Euro V standards
RU VII Kasim/Sorong	10	2.4	● Open access for crude oil receiving facilities ● Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater
Total	**1,031.0**	**6.0**	

Non-fuel Petrochemicals

Refinery	Non-fuel petrochemicals produced	Current design Capacity (Mtons/year)
RU IV Cilacap	Paraxylene	299,000
RU III Plaju	Polypropylene	45,000
RU II Dumai	Green coke	370,000
Total		**714,000**

Since late 2018, we have also been in coordination with the Ministry of Finance to assume partial ownership and management of PT Trans-Pacific Petrochemical Indotama and restart operations of a petrochemical refinery. As of September 30, 2019, we held a 48.6% non-controlling ownership interest in the PT Trans-Pacific Petrochemical Indotama ("TPPI") petrochemical refinery. We have subsequently acquired a majority beneficial ownership interest in TPPI, which will be reflected in our consolidated financial statements for the year ended December 31, 2019.

Description of Existing Refineries

RU II Dumai

RU II Dumai is located in Sumatra and consists of a refinery unit at Dumai. The unit at RU II Dumai commenced operations in 1972 and has undergone periodic revamps and modifications. RU II Dumai is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil, naphtha, LPG, green coke, feedstock for lube base oil plants and low sulfur waxy residual fuel oil ("LSWR") via its primary and secondary process units. RU II Dumai is comprised of a crude distillation unit ("CDU"), high vacuum unit ("HVU"), hydro-cracker units ("HCU"), delay coker units and platformer units.

As of September 30, 2019, RU II Dumai had an NCI of 7.5, its primary process units had a processing capacity of 147.1 mbbls/d through its CDU and its secondary process units had a processing capacity of 59.2 mbbls/d through its hydro-cracker unit, 14.8 mbbls/d through its platformer unit and 30.3 mbbls/d through its delay coker unit.

RU II Dumai uses domestic crude oil as its raw material. The crude oil processed at RU II Dumai comes from our own production and from other oil and gas producers, such as Chevron, and is transported by pipelines and tankers. In 2018, the average total output of RU II Dumai was 140.1 mbbls/d, and the total amount of green coke produced was 393,230.4 Mton. For the nine months ended September 30, 2019, the average total output of RU II Dumai was 144.8 mbbls/d, and the total amount of green coke produced was 299,102.0 Mton. In 2018 and the nine months ended September 30, 2019, the primary processing capacity utilization rate at RU II Dumai was 85.5% and 86.5%, respectively.

To upgrade the quality of GPC, we intend to build a calciner with a production capacity of 300,000 mtpa started by 2020 in order to produce CPC. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

RU III Plaju

RU III Plaju is located in Musi, Sumatra. It commenced operations in 1935 and underwent revamps and modifications in 1982 and 1994. RU III Plaju is able to produce motor gasoline, kerosene, aviation turbine fuel, aviation gas, gas oil, industrial fuel oil, naphtha, LPG, polypropylene, solvent and hydrocarbon refrigerants via its primary and secondary process units.

As of September 30, 2019, RU III Plaju had an NCI of 3.1, its primary process units had a processing capacity of 92.8 mbbls/d and its secondary process units had a processing capacity of 21.0 mbbls/d through its fluidized catalytic cracking united ("FCCU") and 49,795.0 Mton per year through its polypropylene unit. RU III Plaju is comprised of CDU, HVU, FCCU and polypropylene units.

RU III Plaju uses domestic crude oil as its raw material. Substantially all of the crude oil processed at RU III Plaju comes from our own production and from other oil and gas producers and is transported by pipelines and small tankers. In 2018, the average total output of RU III Plaju was 98.9 mbbls/d and polypropylene production was 45,214.1 mt. In the nine months ended September 30, 2019, the average total output of RU III Plaju was 104.0 mbbls/d and polypropylene production was 37,244.0 mt. In 2018 and the nine months ended September 30, 2019, the primary processing capacity utilization rate at RU III Plaju was 79.0% and 78.6%, respectively.

We are currently making improvements to our crude-receiving facility. The objective of this project is to decrease freight costs and optimize the crude intake capacity. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

RU IV Cilacap

RU IV Cilacap consists of two refinery units located in Cilacap, Java. The refinery units at RU IV Cilacap commenced operations in 1976 and 1983 and both were revamped and modified in 1999. RU IV Cilacap is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil, industrial fuel, LSWR, naphtha, LPG, paraxylene, benzene, lube based oil mineral, solvent and asphalt via its primary and secondary process units. RU IV Cilacap is comprised of two fuel oil complex units, one lube oil plants, one asphalt unit and one paraxylene unit.

As of September 30, 2019, RU IV Cilacap had an NCI of 7.4, its primary process units had a processing capacity of 278.0 mbbls/d and its secondary process units had a processing capacity of 212,963.0 Mton of paraxylene per year and 307,986.0 Mton of lube base oil per year.

RU IV Cilacap uses imported light sweet and sour crude and domestic light sweet crude as its raw materials. In 2018, approximately 38.0% of the crude oil processed at RU IV Cilacap came from our own production and from other domestic oil and gas producers, and the balance was imported from Asia, West Africa and the Middle East by tankers. In 2018, the average total output of RU IV Cilacap was 294.9 mbbls/d, paraxylene production was 1,089.4 mbbls, asphalt production was 1,562.7 mbbls, and lube base oil production was 2,456.2 mbbls. For the nine-month period ended September 30, 2019, the average total output of RU IV Cilacap was 297.6 mbbls/d, paraxylene production was 1.158 mbbls, asphalt production was 765.2 mbbls, and lube base oil production was 1,869.2 mbbls. In 2018 and the nine months ended September 30, 2019, the primary processing capacity utilization rate at RU IV Cilacap was 87.3% and 87.4%, respectively.

We are performing an upgrade of RU IV Cilacap to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.1% to 2.0%. We also plan to increase fuel production and operational processing capacity up to 1.1 times its existing capacity. We aim to improve RU IV Cilacap's product quality from EURO II standards to EURO V standards, and to increase the profitability of the refinery from US$3.00 per barrel to US$12.60 per barrel. In addition, under our Cilacap Blue Sky Project, we plan to change the configuration of the naptha processing RU IV Cilacap to improve the quality of our fuel products from lower octane Gasoline RON 88 to the high-octane fuel RON 92.

As part of our revitalization program, we are also making improvements to our residue fluid catalytic-cracking unit in RU IV Cilacap, in order to process LSWR into products, such as RON 92

gasoline, LPG and propylene. This program is expected to increase RU IV Cilacap's production capacity of RON 92 gasoline by 35.7 mbbls/d, of propylene by 4.3 mbbls/d and of LPG by 9.0 mbbls/d.

RU V Balikpapan

RU V Balikpapan consists of two refinery units located in Balikpapan, Kalimantan. The refinery units at RU V Balikpapan commenced operations in 1922 and 1983 and the first unit was revamped/ modified in 1997. RU V Balikpapan is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil and LSWR via its primary process unit and naphtha, LPG, oil base mud and wax via its primary and secondary process units.

As of September 30, 2019, RU V Balikpapan had an NCI of 3.4, its primary process unit had a processing capacity of 231.9 mbbls/d and its secondary process units had a processing capacity of 46.6 mbbls/d for its HCU and 19.1 mbbls/d for its platformer unit. RU V Balikpapan is comprised of a CDU, HVU, HCU and platformer and wax plant units.

RU V Balikpapan uses domestic and imported light sweet crude as its raw material. In 2018, more than half of the crude oil processed at RU V Balikpapan came from our own production and from other domestic oil and gas producers and was transported by pipelines and via tankers, while the balance was imported from Asia and West Africa and was transported by tankers. For the years ended December 31, 2017 and 2018 and the nine-month period ended September 30, 2019, the average total output of RU V Balikpapan was 220.0 mbbls/d, 241.2 mbbls/d and 243.9 mbbls/d, respectively, and the primary processing capacity utilization rate at RU V Balikpapan was 82.4%, 90.3% and 89.2%, respectively.

We are performing an upgrade of RU V Balikpapan to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.4% to 2.0%. We also plan to increase its fuel production and operational processing capacity to up to 1.4 times its existing capacity. We aim to improve its product quality from EURO II standards to EURO V standards.

RU VI Balongan

RU VI Balongan is located in Balongan, Java. RU VI Balongan commenced operations in 1994 and was revamped or modified in 2005. RU VI Balongan is able to produce motor gasoline, kerosene, gas oil, high octane motor gasoline and propylene via its primary and secondary process units.

As of September 30, 2019, RU VI Balongan had an NCI of 11.9, its primary process unit had a processing capacity of 121.2 mbbls/d and its secondary process units had a processing capacity of 71.9 mbbls/d of RCC.

RU VI Balongan comprises a CDU, an atmospheric residual hydro-demetalizer, RCC, propylene recovery unit, propylene receiving units, a residue catalytic cracking off-gas propylene project and a LPG plant.

RU VI Balongan uses domestic crude and imported light sweet crude as its raw materials. In 2018, 61.9% of the crude oil processed at RU VI Balongan came from our own production and from other domestic oil and 100% was transported by tankers and pipelines.

For the years ended December 31, 2017 and 2018 and the nine-month period ended September 30, 2019, the average output of RU VI Balongan was 112.7 mbbls/d, 107.3 mbbls/d and 159.7 mbbls/d, respectively, and the primary processing capacity utilization rate at RU VI Balongan was 90.2%, 85.9%, and 97.0% respectively.

We also process LSWR, an intermediate product from our RU IV Cilacap refinery, and naphtha, an intermediate product from our RU II Dumai, RU III Plaju, RU IV Cilacap and RU V Balikpapan refineries, at RU VI Balongan. In 2018, we processed 8,428.4 mbbls of LSWR and 16,467.5 mbbls of naphtha at RU VI Balongan.

We are performing an upgrade of RU VI Balongan to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.2% to 1.0% and improve its product quality from EURO II standards to EURO V standards. Currently, the feasibility study relating to the foregoing is in progress and we expect it to be completed in 2020.

RU VII Kasim/Sorong

RU VII Kasim/Sorong is located in Sorong, Papua. RU VII Kasim/Sorong commenced operations in 1995. RU VII Kasim/Sorong is able to produce motor gasoline, kerosene, and gas oil via its primary and secondary process units. RU VII Kasim/Sorong uses domestic crude oil as its raw material. All of the crude oil processed at RU VII Kasim/Sorong is comprised of the Government's crude entitlement from other oil and gas producers and is transported by pipelines to our refinery.

As of September 30, 2019, RU VII Kasim/Sorong had an NCI of 2.4, its primary process unit had a processing capacity of 6.1 mbbls/d its secondary process units had a processing capacity of 1.5 mbbls/d for its platformer unit.

RU VII Kasim/Sorong is comprised of a CDU, a naphtha hydro treating unit and platformer unit.

As of September 30, 2019, we were in the EPC bidding stage in relation to the prospective construction of open access infrastructure for crude oil receiving at RU VII Kasim. The objective of this project is to optimize the crude intake capacity. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

Downstream Products

The table below sets forth production volume for our refined products for the periods presented.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(in thousands of bbls)	
Motor gasoline	61,169.9	61,839.3
Kerosene	2,504.6	2,589.8
Automotive diesel	103,849.0	100,849.0
Industrial diesel	306.1	379.2
Industrial fuel	10,232.0	7,478.3
Aviation turbine fuel	19,803.6	21,902.9
LPG	7,173.7	7,305.3
Refrigerants	5.2	5.1
Lube base oil	1,854.3	1,869.2
Petrochemicals and others	19,157.6	26,554.6
Total	**225,235.2**	**230,772.7**

Pertamina Gas Business

Gas Transmission and Distribution Through PGN

Overview

In April 2018, the Issuer acquired the Government's 56.96% interest in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. PGN is a public company that is listed on the Indonesia Stock Exchange, under the ticker symbol "PGAS," and certain additional information regarding PGN, including its annual reports and financial statements, are publicly available. The Issuer is the largest shareholder of PGN.

PGN is a leading integrated natural gas utility in Indonesia, with a dominant position in the natural gas downstream business through the largest distribution and transmission pipeline network in Indonesia. PGN's core business is its gas distribution and transmission segments, through which it operates its downstream business. PGN's gas distribution and transmission segments accounted for 77.8%, 79.2%, 83.9% and 87.8% of its net revenues in 2017, 2018 and the nine months ended September 30, 2018 and 2019, respectively. PGN's gas distribution and transmission involves purchasing natural gas from upstream gas suppliers and reselling it to industrial, commercial and residential customers through its distribution infrastructure as well as transporting natural gas owned by third parties, through its high-pressure transmission pipelines from upstream suppliers for delivery directly to customers of the upstream suppliers.

PGN's distribution and transmission networks represented approximately 10,194 km of pipelines as of September 30, 2019 and the average volume of natural gas delivered through its distribution and transmission business was approximately 3,061 MMscfd in 2018. PGN's distribution network served 2,468 commercial, industrial and power customers and 369,473 households and small businesses in the nine months ended September 30, 2019. PGN's transmission network represented 4,818 km of pipelines as of September 30, 2019 and comprised its Wampu-Belawan, South Sumatra-West Java, Grissik-Duri, Grissik-Batam-Singapore, Kalija and Kepodang-Tambak Lorok and Pertagas transmission pipelines.

PGN's Natural Gas Distribution and Transmission Business

The following table shows PGN's distribution and transmission infrastructure as at the dates indicated:

	As of or for the Nine-Month Periods Ended September 30,	
	2018	**2019**
Distribution Network length (km)	5,233[(1)]	5,376
Average Distribution gas sales (MMscfd)	958	971
Transmission Network length (km)	2,284[(1)]	4,818
Transmission volumes (MMscfd)	2,094	2,036

Note:

(1) Excludes transmission network assets acquired from the Company by PGN in December 2018.

LNG

As of September 30, 2019, we sold 0.8 mtpa of the gas produced through the regasification process at the Arun plant.

CNG

Distribution and Sale of CNG under the CNG Mandate

Our first CNG refueling station was completed in December 2012 and our CNG distribution network is comprised of 52 CNG refueling stations (including the Tambak Lorok and Bitung plants) and seven mobile refueling units ("MRUs"). In April 2018, our CNG business further expanded when we acquired a 56.96% interest in PGN. As of September 30, 2019, our CNG distribution network comprised of 12 CNG refueling stations and four MRUs throughout Java and Sumatera.

Marketing and Trading

We are actively seeking to expand our marketing and trading business. As of September 30, 2019, developments in some of our key marketing and trading investment projects include:

- the development of CB-III Lomanis Tasikmalaya, which is located between Lomanis in Central Java and Padalarang in West Java. The project is targeted for completion in 2021;
- the construction of Kertajati Airport at Majalengka in the West Java region, in order to provide aircraft refilling services at the West Java International Airport. The project is targeted for completion in 2020; and
- the construction of three general purpose ships, which are targeted for delivery by 2021.

Distribution

The table below sets forth sales volume for our refined products for the periods presented.

	For the Nine-Month Periods Ended September 30,	
	2018	2019
	(in million KL)	
Motor gasoline[(1)]	25.4	26.3
Kerosene[(1)]	0.4	0.4
Automotive diesel[(1)]	20.4	20.7
Industrial diesel	0.0	0.0
Industrial fuel	1.0	1.0
Aviation turbine fuel	4.7	4.4
LPG[(1)]	9.8	10.2
Refrigerants	0.0	0.0
Lube base oil	0.3	0.3
Petrochemicals and others	3.6	4.0
Total	**65.7**	**67.4**

Note:

(1) All sales of motor gasoline, kerosene, automotive diesel and LPG in 3kg cylinders are pursuant to our PSO mandate. Our LPG in 3kg cylinders sales were 5.1 mt for the nine-month period ended September 30, 2019. We also sell LPG in 12kg and 50kg cylinders.

The categories for the refined products we distribute are as follows.

Retail Fuel

As of September 30, 2019, there were 6,912 Pertamina-branded retail fuel filling stations in Indonesia. 160 of these retail fuel filling stations are owned and operated by us. The remaining 6,752

retail fuel filling stations are franchise operations, owned and operated by third parties and held for average periods of 20 to 30 years.

We are actively increasing the number of retail fuel filling stations owned and operated by us to secure our retail distribution network. We currently have 160 of these stations and expect to build approximately 26 more stations owned and operated by us by the end of 2019.

Our market share in relation to subsidized fuel products was 99% for the nine-month period ended September 30, 2019 based on BPH MIGAS data, and we estimate our market share in relation to non-subsidized fuel products to be approximately 98% in 2018. Our main competitors in the retail fuel sector are Shell, AKR, BP and Total.

Industrial and Marine Fuel

We estimate our market share in relation to industrial and marine fuel to be approximately 75% as of December 31, 2018. Our main competitors in the industry and marine fuel sector are Shell, Petronas, AKR and Petro Andalan.

Aviation Fuel

We distribute aviation fuel through our 68 airport depots in Indonesia and we also supply airline customers through our partners in the Asia-Pacific, the Middle East and Europe.

Non-fuel, Petrochemical and Other Products

We estimate our market share in relation to non-fuel and petrochemical products to be approximately 54% for bitumen and 53% for aromatic olefin as of September 30, 2019. Our main competitors in the non-fuel and petrochemicals sector are Chandra Asri, Petronas, Shell, Chevron and Esso, and certain other Middle Eastern and Indian producers especially for aromatic and olefin products such as Reliance, Essar Oil, OMPL India, ADNOC and TASWEEQ.

Lubricants

We estimate our market share in relation to lubricants to be approximately 57% as of September 30, 2019. Our main competitors in the lubricants sector are Shell, Castrol, Yamalube, Idemitsu and Repsol, internationally, and in Indonesia we also compete with Federal Oil, Top 1 and Evalube.

Shipping

We have a fleet of vessels to transport oil and gas, and to distribute fuel, non-fuel and petrochemical products to domestic and international markets. The vessels operate across all six of our refinery units and 122 depots.

We operate more than 260 vessels for domestic cargo, of which 144 are owned by us and the rest are chartered. The total cargo size of our fleet, which reflects the amount of cargo which can be shipped, is approximately 132.27 million KL per year and our average effective load factor is approximately 90.8%.

We intend to purchase approximately 107 new vessels by the end of 2026.

We own and manage 104 ports, 166 piers, 13 single-point mooring locations, six ship-to-ship transfer locations, 11 conventional buoy mooring locations and two island berths.

Import of Crude Oil

In the nine months ended September 30, 2019, we imported 60.1 mmbbls or 24.7% of the crude feedstock to support our refineries and used domestic sources to provide the balance, as compared to between 35% and 45% of our feedstock being imported in 2016, 2017 and 2018. The percentage amount of crude oil we import has decreased over time as we continue to source more crude oil from domestic producers in line with the Government's initiative to encourage domestic crude oil sourcing.

In the nine-month period ended September 30, 2019, our largest provider of imported crude oil was Saudi Aramco, from which we imported 26.7 mmbbls, or approximately 44.4% of our total imported crude oil for the period, for our RU IV Cilacap refinery. We sourced approximately 42.1% of our total imported crude oil under the term supply contract with producers, equity holders, national and multinational oil companies and traders or term supply contracts and the balance under spot contracts.

Import of Fuel Products

In the nine months ended September 30, 2019, our integrated supply chain coordinated the import of following refined fuel products:

	For the Nine Months Ended September 30, 2019
	(in mmbbls)
Motor gasoline	94.0
Automotive diesel oil (gas oil 0.25% sulfur)	0.8
Automotive diesel oil (gas oil 0.03% sulfur)	0.1
Marine fuel oil	0.3
Aviation turbine fuel	1.8
LPG	4.2

Related Party Transactions

As of September 30, 2019, trade and other receivables (including subsidy reimbursements due from the Government) owed by our related parties and trade and other payables owed by us to our related parties, including to the Government, comprised 11.2% and 7.3% of our total assets and total liabilities, respectively. In addition, we share common key management with certain of our related parties.

Research and Development

Approximately US$4.4 million is budgeted for our upstream research and development activities in 2019, of which US$2.2 million had been spent as of September 30, 2019.

Employees

The following table provides a breakdown of our Company's (excluding PGN's) employees as of September 30, 2019.

Unit	As of September 30, 2019
Upstream	167
Downstream	9,488
Gas	—
Integrated supply chain	113
Administration (including top management, corporate secretary and human resources)	1,366
Finance, treasury and accounting	954
Company total	**12,088**
Subsidiaries total	**19,680**
Total (Company and subsidiaries)	**31,768**

Environmental Matters

As of September 30, 2019, 14 of our unit operations have gold PROPER ratings (indicating excellent compliance levels), 69 of our unit operations have green PROPER ratings (indicating that they are beyond compliance levels), and 78 of our unit operations have blue PROPER ratings (indicating they are fully compliant). As of September 30, 2019, two of our operating units that had blue PROPER ratings during the July 2017 to June 2018 appraisal period had received a red PROPER rating, which indicates the units are partially out of compliance due to a lack of monitoring activities at various locations.

Legal Proceedings

We are involved in certain judicial and arbitral proceedings before Indonesian courts or arbitral bodies concerning matters arising in connection with the conduct of our business in the ordinary course.

We believe, based on currently available information, that the results of our legal proceedings, in the aggregate, will not have a material adverse effect on our financial condition or operations.

MANAGEMENT

The Management section on page 244 to page 249 of the Original Offering Memorandum shall be amended and supplemented, where applicable, with the following information:

Board of Commissioners

Based on the decision of the General Meeting of Shareholders ("GMS") No. SK 282/MBU/11/2019 dated November 22, 2019, as amended by the decision of GMS No. SK 329/MBU/12/2019 dated December 23, 2019, Basuki Tjahaja Purnama, Budi Gunadi Sadikin, and Condro Kirono were appointed as the new members of the Company's Board of Commissioners and Tanri Abeng, Arcandra Tahar, and Gatot Trihargo were relieved from their respective positions on the Company's Board of Commissioners. Based on the decision of the Decree of the Minister of State-Owned Enterprises No. SK 327/MBU/12/2019 dated December 23, 2019, Isa Rachmatarwata was appointed as a new member of the Company's Board of Commissioners and Suahasil Nazara was relieved from his position on the Company's Board of Commissioners.

The following table sets forth certain information concerning the current members of the Board of Commissioners.

Name	Position	Age	Appointed Since
Basuki Tjahaja Purnama	President Commissioner and Independent Commissioner	53	November 2019
Budi Gunadi Sadikin	Vice President Commissioner	55	November 2019
Condro Kirono	Commissioner	58	November 2019
Ego Syahrial	Commissioner	57	May 2018
Isa Rachmatarwata	Commissioner	53	December 2019
Alexander Lay	Independent Commissioner	45	September 2017

Basuki Tjahaja Purnama was appointed to our Board of Commissioners in November 2019 and is currently President Commissioner. Mr. Purnama previously held the position as director of PT. Nurindra Ekapersada from 1992 to 2005 and Assistant to President Director in the finance division of PT. Simaxindo Primadaya from 1994 to 1995, He also served as Regent of East Belitung from 2005 to 2006, a member of the People's Representative Council of the Republic of Indonesia from 2009 to 2012, Lieutenant Governor of Jakarta from 2012 to 2014 and the Governor of Jakarta from 2014 to 2017. He received his Bachelor of Science Degree in Geological Engineering from Trisakti University in 1989 and his Master's Degree from Prasetiya Mulya Business School.

Budi Gunadi Sadikin was appointed to our Board of Commissioners in November 2019 and is currently Vice President Commissioner. Mr. Sadikin began his career in 1988 as Information Systems Staff in IBM's Asia-Pacific Headquarters in Tokyo and later became Manager, Systems Integration & Professional Services in IBM in 1994. He was General Manager, Electronic Banking and Chief General Manager, Jakarta Region and Chief General Manager, Human Resources in Bank Bali from 1994 to 1999. He joined ABN AMRO Bank Indonesia from 1999 to 2004 and served as Senior Vice-President Director, Consumer and Commercial Banking, before he joined PT Bank Danamon Indonesia Tbk from 2004 to 2006 as EVP, Head of Consumer Banking. He was Director, Micro & Retail Banking from 2006 to 2013 and President Director from 2013 to 2016 in PT Bank Mandiri Tbk. He was Special Staff to the Minister of BUMN from 2016 to 2017 and President Director in PT Inalum (Persero). He received his Bachelor of Science Degree in Nuclear Physics from the Bandung Institute of Technology in 1988 and a certification as a Chartered Financial Consultant and Chartered Life Underwriter from the Singapore Insurance Institute in 2004.

Condro Kirono was appointed to our Board of Commissioners in November 2019. Mr. Kirono served in the National Police of the Republic of Indonesia from 1984 to 2019 and was previously Head

of the Traffic Corps from 2014 to 2016, Chief of Central Java Regional Police from 2016 to 2019 and Head of the National Police Security Maintenance Agency in 2019. He graduated from the Indonesian National Police Academy in 1984.

Isa Rachmatarwata was appointed to our Board of Commissioners in December 2019. Mr. Rachmatarwata started his career in the Ministry of Finance of the Republic of Indonesia in 1991 and eventually held the position of Director General of State Assets. He currently serves on the board of PT Telekomunikasi Indonesia (Persero) Tbk and The Islamic Development Bank. He received a Bachelor's Degree from the Faculty of Mathematics and Natural Sciences from Bandung Institute of Technology in 1990 and a Master of Mathematic Actuarial Science from the University of Waterloo in Canada in 1994.

Board of Directors

Based on the decision of the Decree of the Minister of State Owned Enterprise No. SK-283/MBU/11/2019 dated November 22, 2019, Pahala N. Mansury was relieved of his duty and is replaced by Emma Sri Martini as Finance Director.

Emma Sri Martini was appointed as Finance Director in November 2019. She previously served as President Director of Telkomsel in 2019 and held various other positions, including President Director of PT Sarana Multi Infrastruktur (Persero) from 2009 to 2019 and Director of Finance and Support of PT Perusahaan Pengelola Aset (Persero) from 2004 to 2009. She received a Bachelor's Degree in Information Technology from Bandung Institute of Technology in 1993 and a Master's Degree from Harvard Kennedy School Executive Education in 2011.

Senior Management

Based on Minister Decree No. SK-336/MBU/12/2019 dated December 26, 2019, Mulyono was appointed as Director of Logistics, Supply Chain, and Infrastructure.

Emma Sri Martini. See "— Board of Directors."

Mulyono was appointed as our Director of Logistics, Supply Chain and Infrastructure in December 2019. He previously served in our Company as Vice President of Shipping from 2011 to 2013, Senior Vice President of Shipping from 2013 to 2017 and Senior Vice President of Strategic Asset Planning and Optimization in 2018. He received his Bachelor's Degree in Electrical Engineering from Sepuluh Nopember Institute of Technology ("ITS") in Surabaya, his Master's Degree in Industrial Engineering from Queensland University of Technology (QUT) in Australia and his Doctoral Degree in Ocean Transportation System from ITS.

The Audit Committee

Based on Decision Letter No. 005/KPTS/K/DK/2020 dated January 3, 2020, Basuki Tjahaja Purnama and Alexander Lay have been appointed as Chairman and Vice Chairman of the Company's Audit Committee replacing Tanri Abeng and Gatot Trihargo, who were relieved from their respective positions as members of the Company's Audit Committee. The current Head of the Audit Committee is Basuki Tjahaja Purnama. The other members of the Audit Committee are Alexander Lay, Agus Yulianto, Bonar Lumban Tobing.

Compensation

As of September 30, 2019, we had employee benefits obligations of US$2,237.9 million, including pension and other post-employment benefits.

LEGAL MATTERS

The Legal Matters section on page 348 of the Original Offering Memorandum shall be deleted in their entirety and replaced with the following:

Certain legal matters with respect to the Notes will be passed upon for us by Latham & Watkins LLP as to matters of New York law and U.S. federal securities law and by Ali Budiardjo, Nugroho, Reksodiputro as to matters of Indonesian law. Certain legal matters with respect to the Notes will be passed upon for the Arrangers and Dealers by Allen & Overy LLP as to matters of New York law and U.S. federal securities law and by Ginting & Reksodiputro in association with Allen & Overy LLP as to matters of Indonesian law.

INDEPENDENT PUBLIC ACCOUNTANTS

Our consolidated financial statements as of December 31, 2018, 2017 and 2016 and for the years then ended have been audited, respectively, by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with Standards on Auditing established by the IICPA, as stated in their audit report appearing elsewhere in this Supplemental Offering Memorandum.

Our unaudited interim consolidated financial statements as of September 30, 2019 and for the nine-month periods ended September 30, 2019 and 2018 have been reviewed by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with SRE 2410, established by the IICPA, as stated in their review report appearing elsewhere in this Supplemental Offering Memorandum (presented together with the audit report for the years ended December 31, 2018, 2017 and 2016). A review conducted in accordance with SRE 2410 established by the IICPA is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the IICPA, and as stated in their review report appearing in this Supplemental Offering Memorandum (presented together with the audit report for the years ended December 31, 2018, 2017 and 2016), KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountant, did not audit and do not express any opinion on such unaudited interim consolidated financial statements included elsewhere in this Supplemental Offering Memorandum.

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PT PERTAMINA (PERSERO)
AND ITS SUBSIDIARIES

Unaudited interim consolidated financial statements
as of September 30, 2019
and for the nine-month periods ended September 30, 2019 and 2018
with reports on review of interim financial information

Audited consolidated financial statements
as of December 31, 2018, 2017, and 2016
and for the years then ended
with independent auditors' reports

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
THE UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS
AS OF SEPTEMBER 30, 2019 AND FOR THE
NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018
WITH REPORTS ON REVIEW OF INTERIM FINANCIAL INFORMATION
AND THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS
AS OF DECEMBER 31, 2018, 2017, AND 2016 AND FOR THE YEARS THEN ENDED
WITH INDEPENDENT AUDITORS' REPORT

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PERTAMINA

DIRECTORS' STATEMENT
REGARDING THE RESPONSIBILITY FOR
THE UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS
AS OF SEPTEMBER 30, 2019, AND FOR THE
NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018
AND THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS
AS OF DECEMBER 31, 2018, 2017, AND 2016 AND FOR THE YEARS THEN ENDED

PT PERTAMINA (PERSERO) AND SUBSIDIARIES

We, the undersigned:

1. Name : Ignatius Tallulembang
   Office address : Jl. Medan Merdeka Timur 1A
   Jakarta 10110
   Telephone : 021 - 3815200
   Position : Acting President Director and CEO

2. Name : Emma Sri Martini
   Office address : Jl. Medan Merdeka Timur 1A
   Jakarta 10110
   Telephone : 021 - 3815400
   Position : Finance Director

declare best on our best knowledge and belief that:

1. We are responsible for the preparation and fair presentation of the following accompanying consolidated financial statements of PT Pertamina (Persero) and its subsidiaries (collectively referred to as the "Group") in accordance with Indonesian Financial Accounting Standard and for the related internal control as we determine is necessary to enable the preparations of such consolidated financial statements that are free from material misstatement whether due to fraud or error:
   - The unaudited interim consolidated financial statements as of September 30, 2019 and for the nine-month periods ended September 30, 2019 and 2018; and
   - The audited consolidated financial statements as of December 31, 2018, 2017, and 2016 and for the years then ended.

2. All information contained in the accompanying consolidated financial statements have been adequately and correctly disclose; and

3. The accompanying consolidated financial statements do not contain false information or facts, or omit material information or facts.

Jakarta, December 17, 2019
PT Pertamina (Persero)

Ignatius Tallulembang	Emma Sri Martini
Acting President Director and CEO	**Finance Director**

Building a better working world

Purwantono, Sungkoro & Surja

Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

Tel.: +62 21 5289 5000
Fax: +62 21 5289 4100
ey.com/id

Report on Review of Interim Financial Information

Report No. 004/9/2.1032/JL.0/02/0684-5/1/XII/2019

The Shareholder and the Boards of Commissioners and Directors
PT Pertamina (Persero)

We have reviewed the accompanying interim consolidated financial statements of PT Pertamina (Persero) (the "Company") and its subsidiaries, which comprise the interim consolidated statement of financial position as of September 30, 2019, and the interim consolidated statements of profit or loss and other comprehensive income, changes in equity, and cash flows for the nine-month periods ended September 30, 2019 and 2018, and a summary of significant accounting policies and other explanatory information. Management is responsible for the preparation and fair presentation of these interim consolidated financial statements in accordance with Indonesian Financial Accounting Standards. Our responsibility is to express a conclusion on these interim consolidated financial statements based on our reviews.

Scope of review

We conducted our reviews in accordance with Standard on Review Engagements 2410, "Review of Interim Financial Information Performed by the Independent Auditor of the Entity", established by the Indonesian Institute of Certified Public Accountants. A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants and consequently, does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our reviews, nothing has come to our attention that causes us to believe that the accompanying interim consolidated financial statements do not present fairly, in all material respects, the consolidated financial position of PT Pertamina (Persero) and its subsidiaries as of September 30, 2019, and their consolidated financial performance and cash flows for the nine-month periods ended September 30, 2019 and 2018, in accordance with Indonesian Financial Accounting Standards.

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Report on Review of Interim Financial Information (continued)

Report No. 00479/2.1032/JL.0/02/0684-5/1/XII/2019 (continued)

Other matter

This report has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1933, and is not intended to be, and should not be, used for any other purposes.

KAP Purwantono, Sungkoro & Surja

Drs. Hari Purwantono
Public Accountant Registration No. AP.0684

December 17, 2019

EY
Building a better working world

Purwantono, Sungkoro & Surja

Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

Tel: +62 21 5289 5000
Fax: +62 21 5289 4100
ey.com/id

Independent Auditors' Report

Report No. 02096/2.1032/AU.1/02/0684-4/1/XII/2019

The Shareholder and the Boards of Commissioners and Directors
PT Pertamina (Persero)

We have audited the accompanying consolidated financial statements of PT Pertamina (Persero) (the "Company") and its subsidiaries, which comprise the consolidated statements of financial position as of December 31, 2018, 2017, and 2016, and the consolidated statements of profit or loss and other comprehensive income, changes in equity, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of such consolidated financial statements in accordance with Indonesian Financial Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on such consolidated financial statements based on our audits. We conducted our audits in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether such consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

Purwantono, Sungkoro & Surja
Registered Public Accountants KAP No. 609/KM.1/2015
A member firm of Ernst & Young Global Limited

Auditors' responsibility (continued)

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of PT Pertamina (Persero) and its subsidiaries as of December 31, 2018, 2017, and 2016, and their consolidated financial performance and cash flows for the years then ended, in accordance with Indonesian Financial Accounting Standards.

Other matter

This report has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1933, and is not intended to be, and should not be, used for any other purposes.

KAP Purwantono, Sungkoro & Surja

Drs. Hari Purwantono
Public Accountant Registration No. AP.0684

December 17, 2019

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
AS OF SEPTEMBER 30, 2019 AND DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	As of September 30, 2019 (Unaudited)	As of December 31, 2018	2017	2016
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	2g,2h,6	8,094,779	9,112,312	6,409,827	6,721,568
Restricted cash	2g,2h,7	239,461	108,915	119,671	122,697
Short-term investments	2h	462,696	225,199	249,282	130,820
Trade receivables	2h,2i				
Related parties	2f,41a	1,711,453	1,297,651	1,095,016	1,422,268
Third parties	8a	2,031,624	1,933,455	1,580,627	1,442,452
Due from the Government - current portion	2h,9	2,119,197	1,834,261	1,492,625	1,792,457
Other receivables	2h,2i				
Related parties	2f,41b	217,950	149,178	255,054	242,839
Third parties	8b	997,111	734,312	620,460	649,798
Inventories	2j,10	5,519,113	6,323,165	6,036,137	4,795,022
Prepaid taxes - current portion	2u,40a	672,034	820,598	794,255	567,621
Prepayments and advances	2k	540,334	534,987	476,326	503,382
Other investments	2h,11	74,126	80,171	27,328	43,190
Total Current Assets		**22,679,878**	**23,154,204**	**19,156,608**	**18,434,114**
NON-CURRENT ASSETS					
Due from the Government - net of current portion	2h,9	3,161,232	2,924,148	663,114	-
Deferred tax assets	2u,40e	1,364,869	1,441,866	1,371,080	751,463
Long-term investments	2h,2m,12	2,673,429	2,819,054	2,970,918	3,329,439
Fixed assets	2n,2o,13	12,655,115	12,859,274	12,439,511	12,156,785
Oil and gas and geothermal properties	2o,2p,14	18,683,786	18,614,286	18,031,374	16,397,662
Prepaid taxes - net of current portion	2u,40a	982,996	820,287	829,300	1,469,767
Other non-current assets	2h,15	2,335,313	2,085,333	1,977,470	1,436,864
Total Non-current Assets		**41,856,740**	**41,564,248**	**38,282,767**	**35,541,980**
TOTAL ASSETS		**64,536,618**	**64,718,452**	**57,439,375**	**53,976,094**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION (continued)
AS OF SEPTEMBER 30, 2019 AND DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	As of September 30, 2019 (Unaudited)	As of December 31, 2018	2017	2016
LIABILITIES					
SHORT-TERM LIABILITIES					
Short-term loans	2h,16	1,918,286	4,347,035	452,879	230,293
Trade payables	2h				
Related parties	2f,41c	157,011	78,781	49,277	118,540
Third parties	17	3,296,627	3,597,777	3,900,121	3,290,665
Due to the Government - current portion	2h,18	1,520,667	1,207,743	1,050,619	952,545
Taxes payable	2u,40b				
Income taxes		498,139	467,605	308,803	475,576
Other taxes		256,483	258,405	250,533	251,553
Accrued expenses	2h,19	2,366,426	2,135,509	2,019,896	1,596,612
Long-term liabilities - current portion	2h,2o,20	529,521	420,577	365,959	722,200
Other payables	2h				
Related parties	2f,41d	32,461	54,011	56,625	50,947
Third parties		1,393,990	1,203,426	1,121,494	1,026,808
Deferred revenue - current portion	2r	198,618	202,013	260,838	177,499
Total Short-term Liabilities		**12,168,229**	**13,972,882**	**9,837,044**	**8,893,238**
LONG-TERM LIABILITIES					
Due to the Government - net of current portion	2h,18	818,690	795,082	780,626	732,573
Deferred tax liabilities	2u,40e	3,410,366	3,307,406	2,848,152	2,528,517
Long-term liabilities - net of current portion	2h,2o,20	1,507,529	1,805,300	2,109,767	2,716,909
Bonds payable	2h,21	12,614,222	11,094,096	10,385,873	9,772,656
Employee benefits liabilities	2s,22	2,013,513	1,850,383	2,208,220	2,058,732
Provision for decommissioning and site restoration	2q,23	2,037,159	2,029,735	2,129,337	1,900,093
Deferred revenue - net of current portion	2r	81,028	74,623	42,716	65,715
Other non-current payables	2h	131,124	178,905	84,373	62,903
Total Long-term Liabilities		**22,613,631**	**21,135,530**	**20,589,064**	**19,838,098**
TOTAL LIABILITIES		**34,781,860**	**35,108,412**	**30,426,108**	**28,731,336**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION (continued)
AS OF SEPTEMBER 30, 2019 AND DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	As of September 30, 2019 (Unaudited)	As of December 31, 2018	2017	2016
EQUITY					
Equity Attributable to Owners of the Parent Entity					
Share capital					
Authorized shares - 600,000,000 (2019 and 2018) and 200,000,000 (2017 and 2016) ordinary shares at par value of Rp1,000,000 (full amount) per share					
Issued and paid-up - 171,227,044 shares (2019 and 2018); 133,090,697 shares (2017 and 2016)	25a	16,191,204	16,191,204	13,417,047	13,417,047
Additional paid-in capital	25b	(924,296)	(924,296)	2,736	2,736
Merging entity's equity		-	-	1,804,579	1,801,742
Government contributed assets pending final clarification of status	26	398,557	401,120	1,361	1,361
Other equity components		220,789	607,564	487,699	664,617
Retained earnings	27				
- Appropriated		10,770,470	8,796,357	6,871,101	4,631,441
- Unappropriated		731,157	2,526,772	2,540,195	3,147,043
Total Equity Attributable to Owners of the Parent Entity		**27,387,881**	**27,598,721**	**25,124,718**	**23,665,987**
Non-controlling interests	2c,24	2,366,877	2,011,319	1,888,549	1,578,771
Total Equity		**29,754,758**	**29,610,040**	**27,013,267**	**25,244,758**
TOTAL LIABILITIES AND EQUITY		**64,536,618**	**64,718,452**	**57,439,375**	**53,976,094**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PROFIT OR LOSS AND COMPREHENSIVE INCOME
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the nine-month periods ended September 30,		For the years ended December 31,		
		2019 (Unaudited)	2018 (Unaudited)	2018	2017	2016
Sales and other operating revenues	**2r**					
Domestic sales of crude oil, natural gas, geothermal energy and oil products	28	32,429,455	33,388,274	44,742,511	39,788,784	35,841,696
Subsidy reimbursements from the Government	29	3,654,557	4,333,335	5,632,468	3,572,084	2,568,844
Export of crude oil, natural gas and oil products	30	2,483,980	2,668,122	3,636,953	1,874,281	968,371
Marketing fees		9,430	11,574	15,432	25,474	(257,485)
Revenues from other operating activities	31	597,346	2,786,404	3,906,207	740,100	690,511
TOTAL SALES AND OTHER OPERATING REVENUES		**39,174,768**	**43,187,709**	**57,933,571**	**46,000,723**	**39,811,937**
Cost of sales and other direct costs	**2r**					
Cost of goods sold	32	(29,112,979)	(31,219,633)	(42,787,916)	(33,175,656)	(26,180,963)
Upstream production and lifting costs	33	(3,573,512)	(3,454,896)	(4,386,516)	(3,421,207)	(3,270,000)
Exploration costs	34	(120,070)	(198,355)	(267,680)	(165,356)	(109,196)
Expenses from other operating activities	35	(1,252,486)	(1,010,959)	(1,271,977)	(862,962)	(703,492)
TOTAL COST OF SALES AND OTHER DIRECT COSTS		**(34,059,047)**	**(35,883,843)**	**(48,714,089)**	**(37,625,181)**	**(30,263,651)**
GROSS PROFIT		**5,115,721**	**7,303,866**	**9,219,482**	**8,375,542**	**9,548,286**
Selling and marketing expenses	2r,36	(1,082,200)	(1,026,599)	(1,642,831)	(1,590,202)	(1,339,566)
General and administrative expenses	2r,37	(1,129,282)	(963,482)	(1,329,911)	(1,598,934)	(1,509,290)
Gain (loss) on foreign exchange - net	2r,2t	140,511	(190,420)	19,622	58,137	(57,521)
Finance income	2r,38	400,512	159,658	256,573	233,074	336,634
Finance costs	2r,38	(721,197)	(619,359)	(835,238)	(817,711)	(770,518)
Share in net profit of associates and joint ventures	2c,2r	59,722	178,193	122,724	37,904	18,722
Other expenses - net	2r,39	(333,753)	(109,959)	(80,825)	(830,582)	(877,864)
		(2,665,687)	(2,571,968)	(3,489,886)	(4,508,314)	(4,199,403)
PROFIT BEFORE INCOME TAX		**2,450,034**	**4,731,898**	**5,729,596**	**3,867,228**	**5,348,883**
Income tax expense - net	2u,40c	(1,674,145)	(2,042,682)	(3,013,202)	(1,166,824)	(1,877,649)
PROFIT FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		**775,889**	**2,689,216**	**2,716,394**	**2,700,404**	**3,471,234**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PROFIT OR LOSS AND COMPREHENSIVE INCOME (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the nine-month periods ended September 30,		For the years ended December 31,		
		2019 (Unaudited)	2018 (Unaudited)	2018	2017	2016
PROFIT FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		**775,889**	**2,689,216**	**2,716,394**	**2,700,404**	**3,471,234**
OTHER COMPREHENSIVE (LOSS) INCOME						
Items not to be reclassified to profit or loss in subsequent periods (net of tax):						
Remeasurement of net defined benefit liability	2s	(37,661)	195,686	228,498	(129,059)	(73,373)
Items to be reclassified to profit or loss in subsequent periods (net of tax):						
Foreign exchange difference from translation of financial statements in foreign currency	2c,2t	72,972	124,570	(79,561)	7,060	14,684
Share of other comprehensive income (loss) of associates	2c,2m	(111,260)	(419,939)	(130,775)	(25,134)	1,482
Other comprehensive income (loss), net of tax		**(75,949)**	**(99,683)**	**18,162**	**(147,133)**	**(57,207)**
TOTAL COMPREHENSIVE INCOME FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		**699,940**	**2,589,533**	**2,734,556**	**2,553,271**	**3,414,027**
Adjustment of merging entity's income:						
Owners of the parent entity		-	(45,770)	(45,770)	(81,537)	(173,339)
Non-controlling interests	2c	-	(34,585)	(34,585)	(66,248)	(135,241)
		-	**(80,355)**	**(80,355)**	**(147,785)**	**(308,580)**
PROFIT FOR THE PERIOD/YEAR BEFORE THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT ATTRIBUTABLE TO:						
Owners of the parent entity		731,157	2,504,302	2,526,772	2,540,195	3,147,043
Non-controlling interests	2c	44,732	104,559	109,267	12,424	15,611
		775,889	**2,608,861**	**2,636,039**	**2,552,619**	**3,162,654**
Adjustment of merging entity's comprehensive income:						
Owners of the parent		-	(42,546)	(42,546)	(80,710)	(176,957)
Non-controlling interests	2c	-	(32,682)	(32,682)	(65,549)	(138,292)
		-	**(75,228)**	**(75,228)**	**(146,259)**	**(315,249)**
TOTAL COMPREHENSIVE INCOME FORTHE PERIOD/YEAR BEFORE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT ATTRIBUTABLE TO:						
Owners of the parent		344,382	2,455,497	2,536,559	2,363,277	3,081,541
Non-controlling interests	2c	355,558	58,808	122,769	43,735	17,237
		699,940	**2,514,305**	**2,659,328**	**2,407,012**	**3,098,778**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity											
							Other equity components						
	Notes	Issued and paid-up capital	Advance for share issuance	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other Compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
									Appropriated	Unappropriated			
Balance as of January 1, 2016/ December 31, 2015		**9,864,901**	**3,552,146**	**1,720,396**	**2,736**	**1,361**	**(321,181)**	**1,051,300**	**3,710,670**	**1,420,220**	**21,002,549**	**1,495,494**	**22,498,043**
Adjustment of merging entity's comprehensive income for the year		-	-	176,957	-	-	-	-	-	-	176,957	138,292	315,249
Adjustment of merging entity's other equity transaction		-	-	(95,611)	-	-	-	-	-	-	(95,611)	(72,252)	(167,863)
Differences arising from translation of non-US dollar currency financial statements	2c,2t	-	-	-	-	-	16,980	-	-	-	16,980	(3,181)	13,799
Other comprehensive income from associates		-	-	-	-	-	-	(6,144)	-	-	(6,144)	4,270	(1,874)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	-	(76,338)	-	-	(76,338)	537	(75,801)
Dividends declared	2aa,27	-	-	-	-	-	-	-	-	(499,449)	(499,449)	-	(499,449)
Appropriation of other reserves	27	-	-	-	-	-	-	-	920,771	(920,771)	-	-	-
Capitalization of advance for share issuance		3,552,146	(3,552,146)	-	-	-	-	-	-	-	-	-	-
Profit for the year		-	-	-	-	-	-	-	-	3,147,043	3,147,043	15,611	3,162,654
Balance as of December 31, 2016		**13,417,047**	**-**	**1,801,742**	**2,736**	**1,361**	**(304,201)**	**968,818**	**4,631,441**	**3,147,043**	**23,665,987**	**1,578,771**	**25,244,758**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entity's equity	Additional paid-in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2017/ December 31, 2016		**13,417,047**	**1,801,742**	**2,736**	**1,361**	**(304,201)**	**968,818**	**4,631,441**	**3,147,043**	**23,665,987**	**1,578,771**	**25,244,758**
Impact of consolidated beginning balance of non-controlling interest Etablissements Maurel et Prom SA		-	-	-	-	-	-	-	-	-	252,158	252,158
Adjustment of merging entity's comprehensive income for the year		-	80,710	-	-	-	-	-	-	80,710	65,549	146,259
Adjustment of merging entity's other equity transaction		-	(77,873)	-	-	-	-	-	-	(77,873)	(51,664)	(129,537)
Differences arising from translation of non-US dollar currency financial statements	2c,2t	-	-	-	-	1,225	-	-	-	1,225	3,271	4,496
Other comprehensive income from associates		-	-	-	-	-	(55,421)	-	-	(55,421)	28,050	(27,371)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	(122,722)	-	-	(122,722)	(10)	(122,732)
Dividends declared	2aa,27	-	-	-	-	-	-	-	(907,383)	(907,383)	-	(907,383)
Appropriation of other reserves	27	-	-	-	-	-	-	2,239,660	(2,239,660)	-	-	-
Profit for the year		-	-	-	-	-	-	-	2,540,195	2,540,195	12,424	2,552,619
Balance as of December 31, 2017		**13,417,047**	**1,804,579**	**2,736**	**1,361**	**(302,976)**	**790,675**	**6,871,101**	**2,540,195**	**25,124,718**	**1,888,549**	**27,013,267**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other comprehensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2018/ December 31, 2017		**13,417,047**	**1,804,579**	**2,736**	**1,361**	**(302,976)**	**790,675**	**6,871,101**	**2,540,195**	**25,124,718**	**1,888,549**	**27,013,267**
Adjustment of merging entity's comprehensive income for the year		-	42,546	-	-	-	-	-	-	42,546	32,682	75,228
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk. (Note 1b)		-	-	-	-	-	-	-	-	-	50,281	50,281
Capitalization of advance for share issuance		2,774,157	(1,847,125)	(927,032)	-	-	-	-	-	-	-	-
Differences arising from translation of financial statements	2c,2t	-	-	-	-	97,757	-	-	-	97,757	26,813	124,570
Other comprehensive income from associates		-	-	-	-	-	(238,890)	-	-	(238,890)	(181,049)	(419,939)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	170,164	-	-	170,164	25,522	195,686
Dividends declared	2aa,27	-	-	-	-	-	-	-	(614,939)	(614,939)	-	(614,939)
Appropriation of other reserves	27	-	-	-	-	-	-	1,925,256	(1,925,256)	-	-	-
Profit for the period		-	-	-	-	-	-	-	2,504,302	2,504,302	104,559	2,608,861
Balance as of September 30, 2018 (unaudited)		**16,191,204**	**-**	**(924,296)**	**1,361**	**(205,219)**	**721,949**	**8,796,357**	**2,504,302**	**27,085,658**	**1,947,357**	**29,033,015**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2018/ December 31, 2017		**13,417,047**	**1,804,579**	**2,736**	**1,361**	**(302,976)**	**790,675**	**6,871,101**	**2,540,195**	**25,124,718**	**1,888,549**	**27,013,267**
Adjustment of merging entity's comprehensive income for the year		-	42,546	-	-	-	-	-	-	42,546	32,682	75,228
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk. and PT Pertamina Internasional Eksplorasi dan Produksi (Note 4c)		-	-	-	-	-	13,710	-	-	13,710	68,814	82,524
Capitalization of advance for share issuance		2,774,157	(1,847,125)	(927,032)	-	-	-	-	-	-	-	-
Government contributed assets pending final clarification of status	26	-	-	-	399,759	-	-	-	-	399,759	-	399,759
Differences arising from translation of non-US dollar currency financial statements	2c,2t	-	-	-	-	(59,338)	-	-	-	(59,338)	(20,223)	(79,561)
Other comprehensive income from associates		-	-	-	-	-	(69,138)	-	-	(69,138)	(61,637)	(130,775)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	234,631	-	-	234,631	(6,133)	228,498
Dividends declared	2aa,27	-	-	-	-	-	-	-	(614,939)	(614,939)	-	(614,939)
Appropriation of other reserves	27	-	-	-	-	-	-	1,925,256	(1,925,256)	-	-	-
Profit for the year		-	-	-	-	-	-	-	2,526,772	2,526,772	109,267	2,636,039
Balance as of December 31, 2018		**16,191,204**	**-**	**(924,296)**	**401,120**	**(362,314)**	**969,878**	**8,796,357**	**2,526,772**	**27,598,721**	**2,011,319**	**29,610,040**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2019/ December 31, 2018		**16,191,204**	**-**	**(924,296)**	**401,120**	**(362,314)**	**969,878**	**8,796,357**	**2,526,772**	**27,598,721**	**2,011,319**	**29,610,040**
Adjustment of merging entity's comprehensive income for the year		-	-	-	-	-	-	-	-	-	-	-
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk.		-	-	-	-	-	-	-	-	-	-	-
Capitalization of advance for share issuance		-	-	-	-	-	-	-	-	-	-	-
Government contributed assets pending final clarification of status	26	-	-	-	(2,563)	-	-	-	-	(2,563)	-	(2,563)
Differences arising from translation of non-US dollar currency financial statements	2c,2t	-	-	-	-	(5,854)	-	-	-	(5,854)	78,826	72,972
Other comprehensive income from associates		-	-	-	-	-	(349,070)	-	-	(349,070)	237,810	(111,260)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	(31,851)	-	-	(31,851)	(5,810)	(37,661)
Dividends declared	2aa,27	-	-	-	-	-	-	-	(552,659)	(552,659)	-	(552,659)
Appropriation of other reserves	27	-	-	-	-	-	-	1,974,113	(1,974,113)	-	-	-
Profit for the period		-	-	-	-	-	-	-	731,157	731,157	44,732	775,889
Balance as of September 30, 2019 (unaudited)		**16,191,204**	**-**	**(924,296)**	**398,557**	**(368,168)**	**588,957**	**10,770,470**	**731,157**	**27,387,881**	**2,366,877**	**29,754,758**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the nine-month periods ended September 30,		For the years ended December 31,		
		2019 (Unaudited)	2018 (Unaudited)	2018	2017	2016
Cash flows from operating activities:						
Cash receipts from customers		37,983,176	35,685,553	48,878,496	40,220,288	42,723,514
Cash receipts from Government		4,728,593	4,644,298	7,805,648	3,787,855	3,722,302
Cash receipts from tax restitutions		39,012	15,901	185,016	616,698	39,492
Payments to suppliers		(28,845,482)	(27,662,104)	(38,227,640)	(29,261,802)	(29,211,891)
Payments to the Government		(7,160,966)	(7,755,462)	(11,279,557)	(7,524,628)	(5,173,462)
Payments of corporate income taxes		(2,029,741)	(2,074,610)	(2,688,175)	(2,100,297)	(2,009,016)
Cash paid to employees and management		(1,468,322)	(1,206,024)	(1,640,855)	(1,540,805)	(1,321,422)
Receipts from (placement of) restricted cash		(11,522)	(6,846)	73,109	(156,047)	(494,035)
Receipts of interest		18,763	33,633	63,327	35,616	115,711
Net cash generated from operating activities		**3,253,511**	**1,674,339**	**3,169,369**	**4,076,878**	**8,391,193**
Cash flows from investing activities:						
Proceeds from disposal of short-term investments		97,985	65,279	198,439	99,870	45,807
Proceeds from disposal of long-term investments		-	-	-	15,801	4,647
Interest received from investments		9,259	25,762	13,784	18,240	3,987
Cash receipts from other investing activities		406	167,614	262,222	28,681	-
Proceeds from sale of fixed assets		1,119	284	176	102	2,161
Dividends received form associates		14,783	80,646	214,083	81,648	233,632
Purchases of fixed assets		(974,545)	(741,416)	(1,287,975)	(981,944)	(1,012,676)
Purchases of oil and gas, and geothermal properties		(1,372,460)	(915,571)	(1,482,518)	(891,964)	(1,365,114)
Placements in long-term invesments		(90,654)	(167,445)	(1,062,244)	(659,992)	(336,518)
Placements in short-term investments		(123,260)	(97,433)	(237,577)	(226,322)	(142,759)
Payments for exploration and evaluation assets		(30,474)	(173,774)	(99,538)	(37,200)	(18,438)
Placement of restricted cash		(4)	(21,915)	(22,614)	(29,433)	(10,286)
Addition of participating interest		-	-	-	-	(23,796)
Acquisition of subsidiary net of cash acquired		17,038	-	-	-	-
Cash obtained due to change of control		-	-	-	203,230	-
Net cash used in investing activities		**(2,450,807)**	**(1,777,969)**	**(3,503,762)**	**(2,379,283)**	**(2,619,353)**

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
FOR THE NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the nine-month periods ended September 30,		For the years ended December 31,		
		2019 (Unaudited)	2018 (Unaudited)	2018	2017	2016
Cash flows from financing activities:						
Proceeds from short-term loans	46	5,732,978	6,689,920	9,489,219	4,039,533	2,377,255
Proceeds from bond issuance	46	1,498,855	-	734,407	-	-
Proceeds from long-term loans	46	415,185	220,129	255,931	1,288,204	1,674,448
Repayments of short-term loans	46	(8,353,764)	(3,827,081)	(5,583,278)	(3,786,723)	(4,057,881)
Repayments of long-term loans	46	(518,438)	(443,358)	(465,351)	(2,109,038)	(2,248,368)
Dividend payments	27,46	(317,270)	(329,604)	(585,755)	(867,751)	(554,859)
Payments of finance costs		(336,196)	(275,825)	(538,489)	(523,147)	(530,823)
Repayments of bonds	46	-	(15,443)	(37,649)	-	(139,756)
Receipts from (placement of) restricted cash		(1,043)	(615)	(312)	(13,249)	394
Net cash generated from (used in) financing activities		**(1,879,693)**	**2,018,123**	**3,268,723**	**(1,972,171)**	**(3,479,590)**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(1,076,989)**	**1,914,493**	**2,934,330**	**(274,576)**	**2,292,250**
Effect of exchange rate changes on cash and cash equivalents		59,456	(366,399)	(231,845)	(37,165)	20,652
CASH AND CASH EQUIVALENTS AT THE BEGINNING OF THE PERIOD/YEAR	6	**9,112,312**	**6,409,827**	**6,409,827**	**6,721,568**	**4,408,666**
CASH AND CASH EQUIVALENTS AT THE END OF THE PERIOD/YEAR	6	**8,094,779**	**7,957,921**	**9,112,312**	**6,409,827**	**6,721,568**

The accompanying notes form an integral part of these consolidated financial statements.

1. GENERAL

a. PT Pertamina (Persero) ("the Company")

i. Company profile

The Company was established in accordance with Notarial Deed No. 20 dated September 17, 2003 of Lenny Janis Ishak, S.H. The Company's deed of establishment was approved by the Minister of Law and Human Rights through Letter No. C-24025 HT.01.01.TH.2003 dated October 9, 2003 and through Circular Letter No. 93 attachments No. 11620 dated November 21, 2003. The establishment of the Company is based on Law No. 1 Year 1995 dated March 7, 1995 regarding Limited Liability Company ("PT"), Government Regulation ("PP") No. 12 Year 1998 dated January 17, 1998 regarding the Company (Persero), and PP No. 45 Year 2001 dated June 5, 2001 regarding Amendments to PP No. 12 Year 1998, Law No. 22 Year 2001 dated November 23, 2001 regarding Oil and Gas, Law No. 19 Year 2003 dated June 19, 2003 regarding State-Owned Enterprises ("BUMN"), and PP No. 31 Year 2003 dated June 18, 2003 regarding changes in the status of Perusahaan Pertambangan Minyak dan Gas Bumi Negara (Pertamina, "the former Pertamina Entity") to a state Enterprise (Persero).

The Company's Articles of Association have been amended several times. The latest amendment was made to increase the authorized capital of the Company, under Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., which was approved by the Minister of Law and Human Rights through Decision Letter No. AHU-0008395.AH.01.02. Year 2018 dated April 13, 2018.

In accordance with PP No. 31 Year 2003, all rights and obligations arising from contracts and agreements entered between the former Pertamina Entity and third parties, provided these are not contrary to Law No. 22 Year 2001, were transferred to the Company. In accordance with PP No. 31 Year 2003, the objective of the Company is to engage in the oil and gas business in domestic and foreign markets and in other related business activities. In conducting its business, the Company's objective is to generate income and contribute to the improvement of the economy for the benefit of the people of Indonesia.

At the date of establishment of the Company, all oil and gas and geothermal energy activities of the former Pertamina Entity, including joint operations with other companies, were transferred to the Company. These businesses have been transferred to the Company's subsidiaries. All employees of the former Pertamina Entity became employees of the Company.

ii. Business activities and principal address

In accordance with its Articles of Association under Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., which was registered by the Minister of Law and Human Rights through its Letter No. AHU-0008395.AH.01.02. Year 2018 dated April 13, 2018, the Company shall conduct the following main business:

a. Operate in exploration activities of oil and gas;
b. Operate in exploitation activities of oil and gas;
c. Carry out activities in electrical energy, including but not limited to the exploration and exploitation of geothermal energy, geothermal electricity power plant ("PLTP"), gas power plant ("PLTG") and electricity energy produced by the Company;
d. Implement refining activities that produce fuel oil, special fuel, non-fuel, petrochemicals, gas fuel, Liquified Natural Gas ("LNG") and Gas to Liquid ("GTL") result/other product either and products or intermediate products
e. Conduct activities of the procurement of raw materials, processing, transportation, storage and trading of Biofuels;
f. Conduct operational activities, which includes the transport of petroleum, natural gas, fuel oil, fuel gas and/or result/other products for commercial purposes;
g. Carry out storage activities which includes the reception, the collection and spending of petroleum reservoirs, fuel oil, fuel gas and/or result/other products for commercial purposes;
h. Carry out commercial trade activities which includes the purchase, sale, export and import of petroleum, fuel oil, fuel gas and/or result/other products; the distribution of natural gas through pipelines including commercial electrical energy produced by the Company; and
i. Conduct developmental activities, exploration, production and trading of new and renewable energy, among others, Coal Bed Methane ("CBM"), liquified coal, gasified coal, shale gas, shale oil, bio fuel, diesel fuel, wind energy and biomass.

1. GENERAL (continued)

a. PT Pertamina (Persero) (the Company) (continued)

ii. Business activities and principal address (continued)

In addition to the above main business activities, the Company may conduct business in order to optimize the utilization of available resources as follows:

a. Trading house, real estate, warehousing, tourism, resort, sports and recreation, rest areas, hospitals, education, research, infrastructure, telecommunications, rental services and operation of facilities and infrastructure owned by the Company, the freeway (toll) and shopping centre/mall;
b. Management of Special Economic Zones;
c. Industrial complex management; and
d. Other business activities and association to support its main business.

The Company has processing activities which include the processing of crude oil into oil products and production of Liquified Petroleum Gas ("LPG") and petrochemicals (paraxylene and propylene). The Company owns six Refinery Units ("RU") with installed processing capacities as follows:

RU	Installed processing capacity of crude oil (barrels/day) (unaudited)
RU II - Dumai and Sungai Pakning, Riau	170,000
RU III - Plaju and Sungai Gerong, South Sumatera	133,700
RU IV - Cilacap, Central Java	348,000
RU V - Balikpapan, East Kalimantan	260,000
RU VI - Balongan, West Java	125,000
RU VII - Kasim, West Papua	10,000

The Company, through its subsidiaries, also conduct certain business activities as disclosed in Notes 1b, 43 and 44.

The Company's head office is located at Jl. Medan Merdeka Timur No. 1A, Jakarta, Indonesia.

iii. The Company's Board of Commissioners and Board of Directors

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Board of Commissioners are as follows:

		December 31,		
	September 30, 2019[a]	2018[a]	2017[b]	2016[c]
President Commissioner	Tanri Abeng[e]	Tanri Abeng[e]	Tanri Abeng[e]	Tanri Abeng[e]
Vice President Commissioner	Arcandra Tahar	Arcandra Tahar	Arcandra Tahar	Arcandra Tahar
Commissioner	Gatot Trihargo[d]	Sahala Lumban Gaol	Sahala Lumban Gaol	Sahala Lumban Gaol
Commissioner	Suahasil Nazara	Suahasil Nazara	Suahasil Nazara	Suahasil Nazara
Commissioner	Alexander Lay	Ahmad Bambang	Edwin Hidayat Abdullah	Edwin Hidayat Abdullah
Commissioner	Ego Syahrial	Alexander Lay	Alexander Lay	-
Commissioner	-	Ego Syahrial	-	-

[a] Based on resolution No. SK-142/MBU/05/2018 of the General Meeting Shareholder ("GMS") dated May 30, 2018
[b] Based on resolution No. SK-194/MBU/09/2017 of the GMS dated September 12, 2017
[c] Based on resolution No. SK-68/MBU/03/2016 of the GMS dated March 29, 2016 and No. SK-254/MBU/11/2016 dated November 14, 2016
[d] Based on resolution No. SK-86/MBU/04/2019 of the GMS dated April 30, 2019
[e] Independent Commissioner

1. GENERAL (continued)

a. PT Pertamina (Persero) (the Company) (continued)

iii. The Company's Board of Commissioners and Board of Directors (continued)

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Board of Directors are as follows:

		December 31,		
	September 30, 2019	2018	2017[d]	2016[e]
President Director	Nicke Widyawati[a]	Nicke Widyawati[a]	Elia Massa Manik	Dwi Soetjipto
Vice President Director	-	-	-	Ahmad Bambang
Marketing Director	-	-	Muchamad Iskandar	Muchamad Iskandar
Corporate Marketing Director	Basuki Trikora Putra[b]	Basuki Trikora Putra[b]	-	-
Retail Marketing Director	Mas'ud Khamid[b]	Mas'ud Khamid[b]	-	-
Upstream Director	Dharmawan H. Samsu[a]	Dharmawan H. Samsu[a]	Syamsu Alam	Syamsu Alam
Gas Director	-	-	Yenni Andayani	Yenni Andayani
New and Renewable Energy Director	-	-	-	-
Finance Director	Pahala N. Mansury[c]	Pahala N. Mansury[c]	Arief Budiman	-
Finance and Corporate Strategy Director	-	-	-	Arief Budiman
Human Resources Director	Koeshartanto[a]	Koeshartanto[a]	Nicke Widyawati	-
Human Resources and Information Technology	-	-	-	Dwi Wahyu Daryoto
Logistic, Supply Chain, and Infrastructure Director	Gandhi Sriwidodo[b]	Gandhi Sriwidodo[b]	-	-
Refinery Director	Budi Santoso Syarif[b]	Budi Santoso Syarif[b]	Toharso	Toharso
Mega Project Refinery and Petrochemical Director	Ignatius Tallulembang[c]	Ignatius Tallulembang[c]	Ardhy N. Mokobombang	Rachmad Hardadi
Planning Investment and Risk Management Director	Heru Setiawan[c]	Heru Setiawan[c]	Gigih Prakoso	-
Asset Management Director	M. Haryo Yunianto[b]	M. Haryo Yunianto[b]	Dwi Wahyu Daryoto	-

[a] Effective per August 29, 2018 based on resolution GMS No. SK-232/MBU/08/2018
[b] Effective per April 20, 2018 based on resolution GMS No. SK-97/MBU/04/2018
[c] Effective per September 13, 2018 based on resolution GMS No. SK-242/MBU/09/2018
[d] Based on resolution No. SK-52/MBU/03/2017 of the GMS dated March 16, 2017 and No. SK-256/MBU/11/2017 dated November 27, 2017
[e] Based on resolution No. SK-242/MBU/10/2016 of the GMS dated October 20, 2016 and No. SK-264/MBU/12/2016 dated December 2, 2016

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Audit Committee are as follows:

		December 31,		
	September 30, 2019	2018	2017	2016[e]
Chairman	Tanri Abeng[a]	Tanri Abeng[a]	Tanri Abeng[a]	Tanri Abeng
Vice Chairman	Gatot Trihargo[f]	Sahala Lumban Gaol[c]	Sahala Lumban Gaol[c]	-
Vice Chairman	-	Ahmad Bambang[c]	Edwin Hidayat Abdullah[d]	-
Member	-	-	-	Sahala Lumban Gaol
Member	-	-	Dwi Martani	Dwi Martani
Member	Agus Yulianto[b]	Agus Yulianto[b]	Agus Yulianto	Agus Yulianto
Member	Bonar Lumban Tobing[b]	Bonar Lumban Tobing[b]	Bonar Lumban Tobing	Bonar Lumban Tobing

[a] Effective per May 6, 2015 based on resolution No. SK-60/MBU/05/2015
[b] Effective per January 1, 2016 based on resolution No. 023/KPTS/K/DK/2015
[c] Effective per July 18, 2018 based on resolution No. 005/KPTS/K/DK/2018
[d] Effective per November 14, 2016 based on resolution No. SK-254/MBU/K/11/2016
[e] Effective per September 12, 2017 based on resolution No. SK-194/MBU/K/09/2017
[f] Effective per May 10, 2019 based on resolution No. 004/KPTS/DK//2019

iv. Number of employees

As of September 30, 2019 and 2018, and December 31, 2018, 2017, and 2016, the Group has 33,997; 29,669; 31,569; 30,118; and 29,469 permanent employees (unaudited), respectively.

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements

i. Subsidiaries

As of September 30, 2019, and December 31, 2018, 2017, and 2016 the Group has direct or indirect control of the following subsidiaries:

Subsidiaries	Year of establishment	Percentage of ownership			
		September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Oil and gas exploration and production					
1. PT Pertamina Hulu Energi	1990	100.00%	100.00%	100.00%	100.00%
2. PT Pertamina EP	2005	100.00%	100.00%	100.00%	100.00%
3. PT Pertamina EP Cepu	2005	100.00%	100.00%	100.00%	100.00%
4. Pertamina E&P Libya Limited, British Virgin Island	2005	100.00%	100.00%	100.00%	100.00%
5. PT Pertamina East Natuna	2012	100.00%	100.00%	100.00%	100.00%
6. PT Pertamina EP Cepu ADK	2013	100.00%	100.00%	100.00%	100.00%
7. PT Pertamina Internasional Eksplorasi dan Produksi	2013	100.00%	100.00%	100.00%	100.00%
8. ConocoPhillips Algeria Limited, Cayman Island *)	2013	-	100.00%	100.00%	100.00%
9. PT Pertamina Hulu Indonesia	2015	100.00%	100.00%	100.00%	100.00%
10. PT Pertamina Hulu Rokan (Note 4g)	2018	100.00%	100.00%	-	-
Geothermal exploration and production					
11. PT Pertamina Geothermal Energy	2006	100.00%	100.00%	100.00%	100.00%
Drilling services					
12. PT Pertamina Drilling Services Indonesia	2008	100.00%	100.00%	100.00%	100.00%
Processing and sale of oil and gas products, construction and oil field services, information technology and telecommunications					
13. PT Elnusa Tbk.	1969	41.10%	41.10%	41.10%	41.10%
Oil and gas trading, gas transportation, processing, distribution and storage					
14. PT Pertamina Gas (Note 4a)	2007	-	-	100.00%	100.00%
15. PT Perusahaan Gas Negara Tbk. (Note 4a)	2018	56.96%	56.96%	-	-
Electricity					
16. PT Pertamina Power Indonesia	2016	100.00%	100.00%	100.00%	100.00%
Trading services and industrial activities					
17. PT Pertamina Patra Niaga	1997	100.00%	100.00%	100.00%	100.00%
18. Pertamina International Timor S,A	2015	95.00%	95.00%	95.00%	95.00%
Public fuel filling stations business					
19. PT Pertamina Retail	1997	100.00%	100.00%	100.00%	100.00%
Lubricant processing and marketing					
20. PT Pertamina Lubricants	2013	100.00%	100.00%	100.00%	100.00%
Shipping					
21. PT Pertamina Trans Kontinental	1969	100.00%	100.00%	100.00%	100.00%
22. PT Pertamina International Shipping	2016	100.00%	100.00%	100.00%	100.00%
Air transportation services					
23. PT Pelita Air Service	1970	100.00%	100.00%	100.00%	100.00%
Investment management					
24. PT Pertamina Pedeve Indonesia (formerly PT Pertamina Dana Ventura)	2002	100.00%	100.00%	100.00%	100.00%
Human resources development services					
25. PT Pertamina Training & Consulting	1999	100.00%	100.00%	100.00%	100.00%
Offices, house rental and hotel operations					
26. PT Patra Jasa	1975	100.00%	100.00%	100.00%	100.00%

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

i. Subsidiaries (continued)

Subsidiaries	Year of establishment	Percentage of ownership			
		September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Health services and hospital operations					
27. PT Pertamina Bina Medika IHC (formerly PT Pertamina Bina Medika)	1997	100.00%	100.00%	100.00%	100.00%
Insurance services					
28. PT Asuransi Tugu Pratama Indonesia Tbk. (formerly PT Tugu Pratama Indonesia) ("ATPI") **)	1981	58.50%	58.50%	65.00%	65.00%
Refineries					
29. PT Kilang Pertamina Internasional	2017	100.00%	100.00%	100.00%	-
Liquified Natural Gas ("LNG")					
30. PT Nusantara Regas (Note 4b)	2010	82.78%	82.78%	60.00%	60.00%
Logistics & bunker business and sales & distribution					
31. Pertamina International Marketing and Distribution Pte. Ltd.	2019	100.00%	-	-	-

Subsidiaries	Year of establishment	Total assets before elimination			
		September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Oil and gas exploration and production					
1. PT Pertamina Hulu Energi	1990	4,905,274	4,531,667	4,780,787	4,908,390
2. PT Pertamina EP	2005	7,557,689	7,498,644	7,621,461	7,301,605
3. PT Pertamina EP Cepu	2005	3,440,095	2,992,894	2,608,022	2,103,211
4. Pertamina E&P Libya Limited, British Virgin Island	2005	154	154	154	154
5. PT Pertamina East Natuna	2012	129	129	129	129
6. PT Pertamina EP Cepu ADK	2013	11,468	12,847	18,534	58,545
7. PT Pertamina Internasional Eksplorasi dan Produksi	2013	5,996,973	5,841,041	5,776,299	4,598,908
8. ConocoPhillips Algeria Limited, Cayman Island *)	2013	-	774,216	1,065,720	1,065,720
9. PT Pertamina Hulu Indonesia	2015	2,343,870	1,478,109	304,838	49,019
10. PT Pertamina Hulu Rokan (Note 4g)	2018	785,001	785,000	-	-
Geothermal exploration and production					
11. PT Pertamina Geothermal Energy	2006	2,553,169	2,556,651	2,408,120	2,073,789
Drilling services					
12. PT Pertamina Drilling Services Indonesia	2008	541,889	560,423	574,402	590,357
Processing and sale of oil and gas products, construction and oil field services, information technology and telecommunications					
13. PT Elnusa Tbk.	1969	435,758	390,995	358,319	311,920
Oil and gas trading, gas transportation, processing, distribution and storage					
14. PT Pertamina Gas (Note 4a)	2007	-	-	1,926,760	1,877,883
15. PT Perusahaan Gas Negara Tbk. (Note 4a)	2018	7,235,361	8,764,437	6,293,129	6,834,153
Electricity					
16. PT Pertamina Power Indonesia	2016	129,997	114,721	99,726	101,149
Trading services and industrial activities					
17. PT Pertamina Patra Niaga	1997	1,041,435	908,986	960,394	783,409
18. Pertamina International Timor S,A,	2015	37,583	36,643	28,677	18,712
Public fuel filling stations business					
19. PT Pertamina Retail	1997	232,861	203,312	150,643	136,686

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

Subsidiaries	Year of establishment	Total assets before elimination			
		September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Lubricant processing and marketing					
20. PT Pertamina Lubricants	2013	493,676	413,332	500,637	510,968
Shipping					
21. PT Pertamina Trans Kontinental	1969	351,346	307,519	287,014	254,017
22. PT Pertamina International Shipping	2016	355,342	296,335	217,466	10,000
Air transportation services					
23. PT Pelita Air Service	1970	62,057	60,380	65,300	63,990
Investment management					
24. PT Pertamina Pedeve Indonesia (formerly PT Pertamina Dana Ventura)	2002	62,890	62,098	71,327	157,691
Human resources development services					
25. PT Pertamina Training & Consulting	1999	40,469	39,799	40,768	32,624
Offices, house rental and hotel operations					
26. PT Patra Jasa	1975	248,523	236,119	229,394	90,570
Health services and hospital operations					
27. PT Pertamina Bina Medika IHC (formerly PT Pertamina Bina Medika)	1997	110,163	105,743	111,006	100,083
Insurance services					
28. PT Asuransi Tugu Pratama Indonesia Tbk. (formerly PT Tugu Pratama Indonesia) ("ATPI") **)	1981	1,284,615	923,376	836,387	662,347
Refineries					
29. PT Kilang Pertamina Internasional***)	2017	1,451	1,836	738	-
Liquified Natural Gas ("LNG")					
30. PT Nusantara Regas (Note 4b)	2010	258,882	240,817	277,438	272,925
Logistics & bunker business and sales & distribution					
31. Pertamina International Marketing and Distribution Pte. Ltd. (Note 4l)	2019	3,745	-	-	-

*) Effective liquidation on February 28, 2019.
**) Deduction in the effective percentage of ownership in ATPI due to the issuance of new equity shares by ATPI in 2018.
***) Established based on Notarial Deed of Elmavirna Calvira Malik, S.H., M.Kn. who replace Lenny Janis Ishak, S.H., No. 08 dated November 13, 2017 and has been approved by the Minister of Justice and Human Rights through the decision letter No. AHU-0051207.AH.01.01.Year 2017 dated November 13, 2017.

ii. Associates

The directly owned associates as of September 30, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PPT Energy Trading Co., Ltd.	50.00%	Marketing services
2. PT Trans-Pacific Petrochemical Indotama	48.59%	Processing and sale of oil and gas products and services

The indirectly owned associates as of September 30, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PT Donggi Senoro LNG	29.00%	LNG Processing
2. PT Asuransi Samsung Tugu	19.50%	Insurance
3. Seplat Petroleum Development Company Plc, ("Seplat") Nigeria	20.46%	Oil and gas exploration and production
4. PT Gas Energi Jambi	40.00%	Transportation and distribution of natural gas

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

iii. Joint arrangements

The indirectly owned joint ventures as of September 30, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PT Patra SK	35.00%	Lube Base Oil ("LBO") processing
2. PT Perta-Samtan Gas	66.00%	LNG processing
3. PT Perta Daya Gas	65.00%	LNG regasification
4. PT Indo Thai Trading	51.00%	Petrochemical trading
5. PT Pertamina Rosneft Pengolahan dan dan Petrokimia	55.00%	Development of Petroleum and Petrochemical refineries
6. PT Transportasi Gas Indonesia ("Transgasindo")	59.87%	Transport of natural gas via transmission pipes
7. PT Permata Karya Jasa ("Perkasa")	60.00%	Workshop services, guidance, distribution of labor services Indonesia

PT Pertamina Rosneft Pengolahan dan Petrokimia ("PRPP") was established by Notarial Deed No. 13 dated November 28, 2017 of Mina NG, SH., M.KN., PRPP's Deed of Establishment was approved by the Minister of Justice and Human Rights through letter No. AHU-0053838.AH.01.01.Year 2017 dated November 28, 2017.

As of January 24, 2018, based on amendment of the Articles of Association of Perkasa, the Group no longer possesed control over Perkasa. As a result, the Group recognized investment in Perkasa as an investment in joint venture.

On April 11, 2018, the Company obtained control over PT Nusantara Regas. Previously, the Company recognized investment in PT Nusantara Regas as an investment in joint venture (Note 4b).

The indirectly owned joint operation as of September 30, 2019, is as follows:

Associates	Percentage of ownership	Nature of business
1. Natuna 2 B.V., Netherland	50.00%	Exploration and production

The Group considered the existence of substantive participating rights held by the non-controlling shareholders of PT Perta-Samtan Gas, PT Perta Daya Gas and PT Pertamina Rosneft Pengolahan dan Petrokimia which provide such shareholders with joint control over significant financial and operating policies. With respect to non-controlling rights, the Group does not have control over the significant financial and operating policies of PT Perta-Samtan Gas, PT Perta Daya Gas and PT Pertamina Rosneft Pengolahan dan Petrokimia even though the Group has more than 50% of share ownership.

As of December 31, 2018, 2017 and 2016, The Group considered the existence of substantive participating rights held by the non-controlling shareholders of PT Indo Thai Trading which provide such shareholders with joint control over significant financial and operating policies. With respect to non-controlling rights, the Group does not have control over the significant financial and operating policies of PT Indo Thai Trading even though the Group has more than 50% of share ownership.

Based on Notarial Deed No. 27 dated July 31, 2019, PTTGC International Private Limited sold and transferred its ownership of 3,920,000 shares of PT Indo Thai Trading to PT Patra Trading, a subsidiary of PT Pertamina Patra Niaga. Therefore, from such date, Group controls PT Indo Thai Trading.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a. Basis of preparation of the consolidated financial statements

The accounting and financial reporting policies adopted by the Group conform to the Indonesian financial accounting standards, which are based on Indonesian Statements of Financial Accounting Standards ("SFAS"). The accounting policies were applied consistently in the preparation of the consolidated financial statements as of September 30, 2019, and December 31, 2018, 2017, and 2016 and the nine-month periods ended September 30, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016 by the Group.

The consolidated financial statements, except consolidated statement of cash flows have been prepared on the accrual basis and the measurement basis used is historical cost, except for certain accounts which requires different measurement as disclosed on each account's accounting policies.

The consolidated statements of cash flows have been prepared based on the direct method by classifying the cash flows into operating, investing and financing activities.

The consolidated financial statements are presented in thousands of US dollar (US$), which is also the Group's functional currency, unless otherwise stated.

b. Change in accounting policies and disclosure

i. The adoption of these new/revised standards and interpretations did not result in substantial changes to the Group's accounting policies and had no material effect on the amounts reported in the consolidated financial statements

The following new standards, amendments to existing standards and interpretations have been published and are mandatory for the first time adoption for the Group's financial year beginning January 1, 2019 or later periods. The Group has adopted them, but they have no significant impact to the Group's current business:

- ISAK 33: Foreign Currency Transaction and Advance Consideration
- ISAK 34: Uncertainty in the Treatment of Income Tax
- Amendments to SFAS 24: Employee Benefits
- SFAS 22 (2018 improvement): Business Combination
- SFAS 26 (2018 improvement): Borrowing cost
- SFAS 46 (2018 improvement): Income Tax
- SFAS 66 (2018 improvement): Joint Arrangement

ii. New standards, amendments and interpretations issued but not yet effective

The following are several accounting standards issued by the Indonesian Financial Accounting Standards Board ("DSAK") that are considered relevant to the financial reporting of the Group but not yet effective for consolidated financial statements as of September 30, 2019, and December 31, 2018, 2017, and 2016 and the nine-month periods ended September 30, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016:

Effective January 1, 2020

- Amendments to SFAS 15: Investment in Associates and Joint Ventures, this amendments stipulates that the entity also applies SFAS 71 to financial instruments in associates or joint ventures where the equity method is not applied. This includes long-term interests which substantially form part of the entity's net investment in associates or joint ventures.
- Amendments to SFAS 62: Insurance Contracts, which allow those who meet certain criteria to apply a temporary exemption from SFAS 71 (Deferral Approach) or choose to apply a layered approach (Overlay Approach) to a defined financial asset.
- SFAS 71: Financial Instruments, which regulates the classification and measurement of financial instruments based on the characteristics of the contractual cash flows and the entity's business model; the expectation credit loss method for impairment that produces information that is more timely, relevant and understood by users of financial statements; accounting for hedges that reflects entity risk management is better by introducing more general requirements based on management considerations.
- SFAS 72: Revenue from Contracts with Customers which sets out a comprehensive framework to determine how, when and how much revenue can be recognized.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

b. Change in accounting policies and disclosure (continued)

ii. New standards, amendments and interpretations issued but not yet effective (continued)

Effective January 1, 2020 (continued)

- SFAS 73: Leases, with early adoption permitted specifically for entities that have implemented SFAS 72 which establishes the principle of recognition, measurement, presentation and disclosure of leases by introducing a single accounting model especially for tenants. This SFAS establishes the principle of recognizing, measuring, presenting, and disclosing leases by introducing a single accounting model by requiring right-of-use assets and lease liabilities. There are 2 optional exceptions in the recognition of lease assets and liabilities, namely for: (i) short-term leases and (ii) leases for low value underlying assets.

- Amendment of SFAS 71: Financial Instruments regarding prepayment features with negative compensation which regulates that financial assets with prepayment features that can result to negative compensation meets qualification as contractual cashflows that are solely payments of principal and interest.

- Amendment of SFAS 1: Presentation of Financial Statements and SFAS 25 : Accounting Policies, Changes in accouting estimates and errors which clarifies the definition of material with the aim of harmonizing the definition used in the conceptual framework and some relevant SFASes.

- SFAS 1 (2019 Annual Improvements): Presentation of Financial Statements to revise Paragraph 5 to "...to amend the descriptions used for particular line items in the financial statements and to amend the descriptions used for the financial statements." to conform to the intention of IAS 1 Presentation of Financial Statements paragraph 5.

Effective January 1, 2021

- Amendment of SFAS 22: Business Combinations on Business Definitions. This amendments clarify the definition of business with the aim of assisting the entity in determining whether a transaction should be recorded as a business combination or asset acquisition.

The Group is currently evaluating and has not yet determined the effects of these accounting standards on its Consolidated Financial Statements.

c. Principles of consolidation

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as described in Note 1b.

Subsidiaries are entities over which the Group has control. The Group controls an entity when the Group is exposed or has rights to variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity.

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the Subsidiary and ceases when the Group loses control of the subsidiary.

A change in the ownership interest of a Subsidiary, without a loss of control, is accounted for as an equity transaction.

If the Group losses control over a Subsidiary, it derecognizes the related assets (including goodwill), liabilities, non-controlling interest (”NCI”) and other components of equity while any resulting gain or loss is recognized in profit or loss. Any investment retained is recognized at fair value.

The consolidated financial statements have been prepared using the same accounting policies for transactions and other events in similar circumstances. If a member of the Group uses accounting policies other than those adopted for transactions and events in similar circumstances, appropriate adjustments are made to its financial statements in preparing the consolidated financial statements.

All intercompany accounts and transactions between the Company and its Subsidiaries have been eliminated to reflect the financial position and the results of operations of the Group as one business entity.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

c. Principles of consolidation (continued)

NCI represents the portion of the profit or loss and net assets of the Subsidiaries attributable to equity interests that are not owned directly or indirectly by the Company, which are presented in the consolidated statement of profit or loss and other comprehensive income and under the equity section of the consolidated statement of financial position, respectively, separately from the corresponding portion attributable to the equity holders of the parent company.

Profit or loss and each component of other comprehensive income ("OCI") are attributed to the equity holders of the parent of the Group and to the NCI, even if this results in the NCI having a deficit balance.

For consolidation purpose of subsidiaries using currency other than US dollar as functional currency, assets and liabilities are translated using the Bank of Indonesia middle rate at the end of reporting period. On the other hand, revenue and expenses are translated using the average Bank of Indonesia middle rate during the profit or loss period.

The difference arising from the translation of those subsidiaries' financial statements into the US dollar is presented as "Other comprehensive income - Differences arising from translation of financial statements" account as part of other equity components in the equity section of the consolidated statements of financial position.

d. Business combinations

Business combinations are accounted using the acquisition method as stipulated in SFAS 22 (Revised 2015). The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any NCI in the acquiree. For each business combination, the acquirer measures the NCI in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Transaction costs incurred are directly expensed and included in "Selling, General and Administrative Expenses".

When the Group acquires a business, it assesses the financial assets acquired and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances, and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date and any resulting gain or loss is recognized in profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognized at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration which is deemed to be an asset or liability will be recognized in accordance with SFAS No. 55 (Revised 2014) either in profit or loss or as other comprehensive income. If the contingent consideration is classified as equity, it should not be remeasured until it is finally settled within equity.

At acquisition date, goodwill is initially measured at cost being the excess of the aggregate of the consideration transferred and the amount recognized for NCI over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the Subsidiary acquired, the difference is recognized in profit or loss. Afterwards, impairment test on goodwill will be examined at the end of every subsequent period.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is allocated from the acquisition date to each of the Group's cash-generating units ("CGU") that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquirer are assigned to those CGUs.

Where goodwill forms part of a CGU and part of the operation within that CGU is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

d. Business combinations (continued)

In accordance with the provision of SFAS No. 22 (Revised 2015), if the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group shall report in its consolidated financial statements provisional amounts for the items for which the accounting is incomplete. During the measurement period, the Group shall retrospectively adjust the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date and, if known, would have affected the measurement of the amounts recognized as of that date.

The Company classified its investment in PT Badak Natural Gas Liquefaction ("Badak NGL") as available-for-sale financial asset at cost because the Company, in substance, does not control those companies as its operations are controlled by the natural gas producers. These investments are measured at cost since their fair values are not reliably measurable.

e. Business combination under common control

Business combination transaction under common control, in the form of transfer of business within the framework of reorganization of entities under the same business group is not a change of ownership in economic substance, therefore it would not result in a gain or loss for the group as a whole or to the individual entity within the same group, therefore the transactions are recorded using the pooling-of-interests method.

The entity that disposed and received the business records the difference between the consideration received/transferred and the carrying amount of the disposed business/carrying amount of any business combination transaction in equity and presents it in "Additional Paid-in Capital" account.

In applying the pooling-of-interests method, the components of the financial statements for the period during which the business combination occurred and for other periods presented for comparison purposes are presented in such a manner as if the combination has already occurred since the beginning of the period in which the entities were under common control.

f. Related party transactions

The Company enters into transactions with related parties as defined in SFAS 7 (Revised 2015): Related Party Disclosures. All significant transactions and balances with related parties are disclosed in the notes to these consolidated financial statements.

g. Cash and cash equivalents

Cash and cash equivalents are cash on hand, cash in banks, and time deposits with maturity periods of three months or less at the time of placement and which are not used as collateral or are not restricted.

For the purpose of the consolidated statements of cash flows, cash and cash equivalents are presented net of overdrafts.

Cash and cash equivalents which are restricted for repayment of currently maturing obligations are presented as restricted cash under the current assets section, while cash and cash equivalents which are restricted to repay obligations maturing after one year from the date of consolidated statement of financial position are presented as part of other non-current assets.

h. Financial instruments

i. Financial assets

Initial recognition

Financial assets are classified as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets, or as derivatives designated as hedging instruments in an effective hedge. The classification depends on the nature and purpose for which the asset was acquired and is determined at the time of initial recognition.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

i. Financial assets (continued)

Initial recognition (continued)

Financial assets are recognized initially at fair value, and in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are added to the fair value.

Subsequent measurement

The subsequent measurement of financial assets depends on their classification as follows:

i. Financial assets at fair value through profit or loss
Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss.

ii. Loans and receivables
Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market.

iii. Available-for-sale (“AFS”) financial assets
AFS financial assets are non-derivative financial assets that are designated as available-for-sale or are not classified in any of the two preceding categories. After initial measurement, AFS financial assets are measured at fair value with unrealized gains or losses recognized in equity until the investment is derecognized. At that time, the cumulative gain or loss previously recognized in equity is reclassified to the consolidated statement of profit or loss and other comprehensive income as a reclassification adjustment.

iv. Held-to-maturity invesments
Non-derivative financial assets with fixed payments, and fixed liabilities and maturity liabilities are classified as held to maturity when the Group has positive intentions and capabilities to maintain them until maturity. After initial measurement, held to maturity investments are measured at amortized cost using the Effective Interest Rate ("EIR") method. Amortization of EIR is recognized as financial income in profit or loss. Losses arising from a decrease in value are recognized in profit or loss as a financial expense.

Impairment of financial assets

Assets carried at amortized cost

The Group assesses, at the end of each reporting period, whether there is objective evidence that a financial asset or group of financial assets is impaired.

The criteria that the Group uses to determine that there is objective evidence of an impairment loss include:
i. default or delinquency in payments by the debtor;
ii. significant financial difficulty of the debtor;
iii. a breach of contract, such as a default or delinquency in interest or principal payments;
iv. the lenders, for economic or legal reasons relating to the borrower’s financial difficulty, granting to the borrower a concession that the lenders would not otherwise consider;
v. the probability that the debtor will enter bankruptcy or other financial reorganisation;
vi. the disappearance of an active market for that financial asset because of financial difficulties; or
vii. observable data indicating that there is a measurable decrease in the estimated future cash flows from a portfolio of financial assets since the initial recognition of those assets, although the decrease cannot be traced yet to the individual financial assets in the portfolio, including:
    1. adverse changes in the payment status of borrowers in the portfolio; and
    2. national or local economic conditions that correlate with defaults on the assets in the portfolio.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

i. Financial assets (continued)

Impairment of financial assets (continued)

If there is an objective evidence that an impairment loss has occurred, the amount of loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future credit losses that have not been incurred) discounted at the financial asset's original EIR. The carrying amount of the asset is reduced either directly or through the use of a provision account. The amount of the loss is recognized in the profit or loss.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized (such as an improvement in the debtor's credit rating), the previously recognized impairment loss will be reversed either directly or by adjusting the provision account. The reversal amount is recognized in the profit or loss and the amount cannot exceed what the amortized cost would have been had the impairment not been recognized at the date the impairment was reversed.

Assets classified as available-for-sale

When a decline in the fair value of an available-for-sale financial asset has been recognized directly in equity and the decline is significant and prolonged or when there is objective evidence that the assets were impaired, the cumulative loss that had been recognized in equity will be reclassified from equity to the profit or loss even though the financial asset has not been derecognized. The amount of the cumulative loss that is reclassified from equity to the profit or loss is the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in the profit or loss.

The impairment loss recognized in the profit or loss on equity instrument cannot be reversed through the profit or loss. Increases in fair value subsequent to the impairment are recognized in OCI.

Derecognition

A financial asset, or where applicable, a part of a financial asset or part of a group of similar financial assets, is derecognized when:

(i) The contractual rights to receive cash flows from the asset have expired; or
(ii) The Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a "pass-through" arrangement, and either (a) the Group has transferred substantially all the risks and rewards of the financial asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

ii. Financial liabilities

Initial recognition

Financial liabilities are classified as financial liabilities at fair value through profit or loss and other financial liabilities that are not held for trading or not designated at fair value through profit or loss. The Group determines the classification of its financial liabilities at initial recognition.

Financial liabilities are recognized initially at fair value and, in the case of financial liabilities recognized at amortized cost, include directly attributable transaction costs.

The Group's financial liabilities which are classified as other financial liabilities include short-term loans, trade payables, due to the Government, accrued expenses, long-term liabilities, other payables, bonds payable, and other non-current payables.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

ii. Financial liabilities (continued)

Subsequent measurement

The measurement of financial liabilities depends on their classification as follows:

i. Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivative liabilities are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognized in the consolidated statement of profit or loss and other comprehensive income.

ii. Financial liabilities at amortized cost

After initial recognition, interest-bearing loans and borrowings are subsequently measured at cost using the EIR method. At the reporting date, the accrued interest is recorded separately from the respective principal loans as part of current liabilities. Gains and losses are recognized in the consolidated statement of profit or loss and other comprehensive income when the liabilities are derecognized as well as through the amortization process using the EIR method.

Derecognition

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognized in the consolidated statement of profit or loss and other comprehensive income.

A financial liability is derecognized when the obligation under the liability is discharged, or cancelled or has expired.

EIR method

The EIR method is a method of calculating the amortized cost of a financial asset and of allocating interest income over the relevant period.

iii. Offsetting financial instruments

Financial assets and liabilities are offset and the net amount is reported in the consolidated statements of financial position, when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or to realize the asset and settle the liability simultaneously.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

iv. Derivative financial instruments and hedge accounting

The Group uses derivative foreign currency forward and option contracts to hedge its foreign currency risks. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

The Company entered into forward and currency option contracts that are used as a hedge for the exposure to changes in cash flows relating to interest payments and bonds repayment due to changes in foreign exchange rates. Such forward and option contracts do not meet the criteria of hedge accounting.

i. Receivables

Trade and other receivables are initially recognized at fair value and are subsequently measured at amortized cost using the effective interest method, less provision for any impairment. If collection is expected in one year or less (or in the normal operating cycle of the business if longer), these receivables are classified as non-current assets.

j. Inventories

Crude oil and oil product inventories are recognized at the lower of cost or net realizable value.

Cost is determined based on the average method and comprises all costs of purchases, costs of conversion and other costs incurred in bringing the inventory to its present location and current condition.

The net realizable value of subsidized fuel products ("BBM") are recognized at the lower of next month Government decreed price and the formula price.

The net realizable value of 3 kg LPG cylinders is the Aramco LPG contract price plus distribution costs and a margin (alpha), less the estimated costs of completion and the estimated costs necessary to make the sale.

Materials such as spare parts, chemicals and others are stated at average cost. Materials exclude obsolete, unusable and slow-moving materials which are recorded as part of other assets under the non-current assets section.

A provision for obsolete, unuseable and slow-moving materials is provided based on management's analysis of the condition of such materials at the end of the year.

k. Prepayments and advances

Prepayments are amortized on a straight-line basis over the estimated beneficial periods of the prepayments.

l. Assets held for distribution to the Company

Assets held for distribution to the Company are recognized at the lower of carrying amount and fair value less costs to sell.

m. Long-term investments

i. Investments in associates

Associates are all entities over which the Group has significant influence but not control, generally accompanying a shareholding of between 20% and 50% of the voting rights. Investments in associates are accounted for using the equity method of accounting and are initially recognized at cost. The Group's investment in associates includes goodwill identified on acquisition, net of any accumulated impairment loss.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

m. Long-term investments (continued)

i. Investments in associates (continued)

The Group's share of its associates' post-acquisition profits or losses is recognized in the profit or loss, and its share of post-acquisition movements in other comprehensive income is recognized in OCI.

Dilution gains and losses arising from investments in associates are recognized in the profit or loss.

ii. Investment property

Investment property consists of land and buildings held by the Group to earn rental income or for capital appreciation, or both, rather than for use in the production or supply of goods or services, administrative purposes or sale in the normal course of business.

An investment property is measured using the cost model that is stated at cost including transaction costs less accumulated depreciation and impairment losses, if any, except for land which is not depreciated. Such cost includes the cost of replacing part of the investment property, if the recognition criteria are satisfied, and excludes operating expenses involving the use of such property.

Building depreciation is computed using the straight-line method over the estimated useful lives of buildings ranging from 10 to 25 years.

An investment property is derecognized upon disposal or when such investment property is permanently withdrawn from use and no future economic benefits are expected from its disposal. Gains or losses arising from the derecognition or disposal of investment property are recognized in the profit or loss in the year such derecognition or disposal occurs.

Transfers to investment property are made when there is a change in use, evidenced by the end of owner-occupation or commencement of an operating lease to another party. Transfers from investment property are made when there is a change in use, evidenced by the commencement of owner-occupation.

For a transfer from investment property to owner-occupied property, the Group uses the cost method at the date of change in use. If owner-occupied property becomes an investment property, the Group recognized the investment property in accordance with the fixed asset policies the date of change in use.

n. Fixed assets

The Group applies accounting policy on fixed assets as stipulated in SFAS 16 (Revised 2015), as follows:

Direct ownership

Land is recognized at cost and not depreciated. Fixed assets are initially recognized at cost and subsequently, except for land, carried at cost less accumulated depreciation and any impairment losses.

Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The Group recognized significant repair and maintenance costs as fixed assets. The carrying amount of the replaced part is derecognized. All other repairs and maintenance are charged to the profit or loss during the financial period in which they are incurred.

Initial legal costs incurred to obtain legal rights are recognized as part of the acquisition cost of the land, and these costs are not depreciated. Costs related to renewal of land rights are recognized as intangible assets and amortized during the period of the land rights.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

n. Fixed assets (continued)

Fixed assets, except land, are depreciated using the straight-line method over their estimated useful lives as follows:

	Years
Tanks, pipeline installations and other equipment	5-25
Refineries	10-20
Buildings	5-25
Ships and aircrafts	6-25
Moveable assets	5-20
Major repairs and maintenance	3

At each financial year-end, the residual values, useful lives and methods of depreciation of assets are reviewed and adjusted prospectively, as appropriate.

When assets are retired or otherwise disposed of, their carrying values are eliminated from the consolidated financial statements, and the resulting gains and losses on the disposal of fixed assets are recognized in the profit or loss.

Assets under construction

Assets under construction represent costs for the construction and acquisition of fixed assets and other costs. These costs are transferred to the relevant fixed asset account when the construction is complete. Depreciation is charged from the date the assets are available for use.

o. Leases

The Group classifies leases based on the extent to which risks and rewards incidental to the ownership of a leased asset are vested upon the lessor or the lessee, and the substance of the transaction rather than the form of the contract, at the time of initial recognition.

Group as Lessee

i. A lease is classified as a finance lease if it transfers substantially all the risks and rewards incidental to ownership of the leased assets. Such leases are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant periodic rate of interest on the remaining balance of the liability. Finance charges are charged directly to profit or loss.

ii. A lease is classified as an operating lease if it does not transfer substantially all the risks and rewards incidental to ownership of the leased asset. Accordingly, the related lease payments are recognized in profit or loss on a straight-line basis over the lease term.

Group as Lessor

Leases in which the group does not transfer substantially all the risks and rewards of ownership of an asset are classified as operating leases initial direct costs in caused in negotiating and arranging an operating leases are added to the carrying amount of the leased asset and recognized over the lease term on the same basis of rental income. Contingent rents are recognized as revenues in the period in which they are earned.

p. Oil and gas and geothermal properties

i. Exploration and evaluation assets

Oil and natural gas, as well as geothermal exploration and evaluation expenditures, are accounted for using the successful efforts method of accounting. Costs are accumulated on a field by field basis.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

p. Oil and gas and geothermal properties (continued)

i. Exploration and evaluation assets (continued)

Geological and geophysical costs are expensed as incurred.

Costs to acquire rights to explore for and produce oil and gas are recorded as unproved property acquisition costs for properties where proved reserves have not yet been discovered, or proved property acquisition costs if proved reserves have been discovered.

The costs of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells are capitalized as part of assets under construction - exploratory and evaluation wells, within oil and gas properties pending determination of whether the wells have found proved reserves. If the well has not found proved reserves, the capitalized costs of drilling the well are then charged to profit or loss as a dry hole expense.

Afterwards, exploration and evaluation assets are reclassified from exploration and evaluation assets when evaluation procedures have been completed. Exploration and evaluation assets for which commercially-viable reserves have been identified are reclassified to development assets. Exploration and evaluation assets are tested for impairment immediately prior to reclassification out of exploration and evaluation assets.

ii. Development assets

The costs of drilling development wells including the costs of drilling unsuccessful development wells and development-type stratigraphic wells are capitalized as part of assets under construction of development wells until drilling is completed. When the development well is completed on a specific field, it is transferred to the production wells.

iii. Production assets

Production assets are aggregated exploration and evaluation assets and development expenditures associated with the producing wells. Production assets are depleted using a unit-of-production method on the basis of proved developed reserves, from the date of commercial production of the respective field.

iv. Other oil and gas and geothermal assets

Other oil and gas and geothermal properties are depreciated using the straight-line method over the lesser of their estimated useful lives or the term of the relevant Production Sharing Contract ("PSC") are as follows:

	Years
Installations	3-30
LPG plants	10-20
Buildings	5-30
Moveable assets	2-27
Geothermal wells	10-20

Land and land rights are stated at cost and are not amortized.

The useful lives and methods of depreciation of assets are reviewed, and adjusted prospectively if appropriate, at least at each financial year-end. The effects of any revisions are recognized in profit or loss, when the changes arise.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

p. Oil and gas and geothermal properties (continued)

iv. Other oil and gas and geothermal assets (continued)

Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of the replaced part is derecognized. All other repairs and maintenance are charged to the profit or loss during the financial period in which they are incurred.

The accumulated costs of the construction, installation or completion of buildings, plant and infrastructure facilities such as platforms and pipelines are capitalized as assets under construction. These costs are reclassified to the relevant fixed asset accounts when the construction or installation is ready for use. Depreciation is charged from that date.

q. Provision for decommissioning and site restoration

The provision for decommissioning and site restoration provides for the legal obligations associated with the retirement of oil and gas properties including the production facilities that result from the acquisition, construction or development and/or normal operation of such assets. The retirements of such assets, other than temporary suspension of use, are removed from service including sale, abandonment, recycling or disposal in some other manner.

These obligations are recognized as liabilities when a constructive obligation with respect to the retirement of an asset is incurred. An asset retirement cost equivalent to these liabilities is capitalized as part of the related asset's carrying value and is subsequently depreciated or depleted over the asset's useful life. These obligations are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation.

The increase in these obligations due to the passage of time is recognised as an interest expense. The capitalised assets are depreciated on a straight-line basis over the lesser of their estimated useful lives or the term of the PSC for other oil and gas assets and using a unit-of-production method for the production assets.

The changes in the measurement of these obligations that result from changes in the estimated timing or amount of the outflow of resources embodying economic benefits required to settle the obligation, or a change in the discount rate will be added to or deducted from the cost of the related asset in the current period. The amount deducted from the cost of the asset should not exceed its carrying amount. If a decrease in the liability exceeds the carrying amount of the asset, the excess is recognised immediately in profit or loss. If the adjustment results in an addition to the acquisition cost of an asset, the Company and Subsidiaries will
consider whether this is an indication that the new carrying amount of the asset may not be fully recoverable. If there is such an indication, the Company and Subsidiaries will test the asset for impairment by estimating its recoverable amount and will account for any impairment loss incurred.

Provision for environmental issues that may not involve the retirement of an asset, where the Group is a responsible party, is recognized when:
- the Group has a present legal or constructive obligation as a result of past events;
- it is probable that an outflow of resources will be required to settle the obligation; and
- the amount has been reliably estimated.

Asset retirement obligations for downstream facilities generally become firm at the time the facilities are permanently shutdown and dismantled. However, these facilities have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligation. The Group performs periodic reviews of its downstream assets for any changes in facts and circumstances that might require recognition of asset retirement obligations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

q. Provision for decommissioning and site restoration (continued)

Group are required to place funds in restricted bank accounts, where applicable, which represent the deposits for the site restoration, decommissioning and post operation obligations. These deposits are maintained in joint bank accounts between SKK Migas and the Group and can only be used for such purposes with approval from SKK Migas, or the amounts should be transferred to SKK Migas if the activities are not conducted by the Company and Subsidiaries.

r. Revenue and expense recognition

i. Revenue

Revenue from the production of crude oil and natural gas are recognized on the basis of the provisional entitlements method at the point of lifting. Differences between the actual liftings of crude oil and natural gas result in a receivable when final entitlements exceed liftings of crude oil and gas (underlifting position) and in a payable when lifting of crude oil and natural gas exceed final entitlements (overlifting position). Underlifting and overlifting volumes are valued based on the annual weighted average Indonesian Crude Price ("ICP") (for crude oil) and price as determined in the respective Sale and Purchase Contract (for natural gas).

The Company recognizes subsidy revenue as it sells the subsidy products and becomes entitled to the subsidy.

Revenue from sales of goods and services is recognized when the significant risks and rewards of ownership of the goods are transferred to the buyer and when such services are performed, respectively.

Penalty income from overdue receivables from BBM sales is recognized when the Company and its customers agree on the amount of the penalties and there is evidence that the customers have committed to pay the penalties.

Revenues from gas distribution and toll fees from gas transmission are recognized when the gas is distributed or transmitted to the customers based on the gas meter readings.

Revenue arising from the operation of the asset and pipeline transmission is recognized after the service is rendered and is measured based on the unit of gas which has been transported during such period.

The cost and revenue involving sales of electricity among PGE, geothermal contractors and PT Perusahaan Listrik Negara (Persero) ("PLN") are recorded based on Energy Sales Contracts under a Joint Operating Contracts ("JOC"). The contracts stipulate that the sale of electricity from the JOC contractors to PLN is to be made through PGE in the same amount of the purchase costs as the electricity from the JOCs.

Excess and/or shortfall of revenue from differences of formula retail selling price and Government's stipulated selling price ("Disparity of Selling Price") of certain type of fuel ("JBT") Diesel Fuel and special fuel assignment ("JBKP") Premium are recognized in the period when sale of JBT Diesel Fuel and JBKP Premium occurs as long as the settlement and/or collectability of such Disparity of Selling Prices is certain at the completion date of the financial statements.

The Company records such excess and/or shortfall of revenue from the Disparity of Selling Prices in revenue from other operating activities account because it is part of the Company's operations.

Deferred revenue consist of:
- amounts billed and collected involving "take or pay" gas quantities, which will be recognized as revenue when the related gas quantities are delivered to customers or when the contract expires.
- payment for rental and services charges received upfront.
- rental revenue that is received in advance.

ii. Expense

Expense is recognized when incurred on an accrual basis.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

s. Pension plan and employee benefits

i. Pension obligations

Entities within the Group operate various pension schemes. The Group has both defined benefit and defined contribution plans. A defined contribution plan is a pension plan under which the Group pays fixed contributions into a separate entity. The Group has no legal or constructive obligations to pay further contributions if the fund does not hold sufficient assets to pay all employee the benefits relating to employee service in the current and prior years.

The Group is required to provide a minimum amount of pension benefit in accordance with Labour Law No. 13/2003 or the Group's Collective Labour Agreement ("the CLA"), whichever is higher. Since the Labour Law or the CLA sets the formula for determining the minimum amount of pension benefits, in substance, pension plans under the Labour Law or the CLA represent defined benefit plans.

The liability recognized in the statement of financial position in respect of the defined benefit pension plans is the present value of the defined benefit obligation at the end of the reporting date less the fair value of plan assets.

The defined benefit obligation is calculated annually by independent actuaries using the projected unit credit method.

Expense charged to profit or loss includes current service costs, interest expense/income, past service cost and gains and losses on settlements. Gains or losses on the curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs.

Remeasurements arising from defined benefit retirement plans are recognized in OCI.

Termination benefits are payable when an employee's employment is terminated by the Group before the normal retirement date, or whenever an employee accepts voluntary redundancy in exchange for these benefits.

The Group recognizes the termination benefits at the earlier of the following dates: (a) when the Group can no longer withdraw the offer of those benefits; and (b) when the Group recognizes restructuring costs involving the payment of termination benefits.

ii. Other post-employment obligations

Companies within the Group provide "post retirement" healthcare benefits to their retired employees. This benefit is eligible for the employee that remains working up to retirement age and approaching a minimum service period. The expected cost of this benefit is accrued over the period of employment using the projected unit credit method. This obligation is valued annually by independent qualified actuaries.

t. Transactions and balances in non-US dollar denomination

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the functional currency).

Non-US dollar currency transactions are translated into US dollar using the exchange rates prevailing at the dates of the transactions. At each reporting date, monetary assets and liabilities denominated in non-US dollar currency are translated into US dollar using the closing exchange rate. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the profit or loss, except when deferred in equity as qualifying cash flows hedges and qualifying net investment hedges.

For domestic and foreign subsidiaries that are not integral to the Company's operations and for which the functional currency is not the US dollar, the assets and liabilities are translated into US dollars at the exchange rates prevailing at the date of statement of financial position.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

t. Transactions and balances in non-US dollar denomination (continued)

The exchange rates used as of September 30, 2019 and December 31, 2018, 2017, and 2016 were as follows (full amount):

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
1,000 Rupiah/US dollar	0.07	0.07	0.07	0.07
Singapore dollar/US dollar	0.72	0.73	0.75	0.69
100 Japanese Yen/US dollar	0.93	0.91	0.89	0.86
Hong Kong dollar/US dollar	0.13	0.13	0.13	0.13
Euro/US dollar	1.09	1.14	1.19	1.05
Malaysian Ringgit/US dollar	0.24	0.24	0.25	0.22
Algerian Dinar/US dollar	0.01	0.01	0.01	0.01

u. Income tax

Current Income Tax

Current tax assets and liabilities are measured at the amount expected to be refunded from or paid to the taxation authority. The tax rates and tax regulations used to calculate these amounts are those that have been enacted or substantively enacted at the reporting date in the country where the Group operates and produce taxable income.

Interest and penalties are presented as part of income or other operating expenses because they are not considered as part of the income tax expense.

The Group periodically evaluates positions reported in Annual Tax Returns ("SPT") in connection with situations in which application of certain tax regulation are subject to interpretation. Where appropriate, the Group establishes provision based on the amounts expected to be paid to the tax authorities including consideration of tax court and supreme court decision in case of Group's appeal process.

Corrections to taxation obligations are recorded when an assessment is received, or for assessment amounts appealed against by the Group, when: (1) the result of the appeal is determined, unless there is significant uncertainty as to the outcome of such an appeal, in which event the impact of the amendment of tax obligations based on an assessment is recognized at the time of making such appeal, or (2) at the time based on knowledge of developments in similar cases involving matters appealed, in rulings by the Tax Court or the Supreme Court, where a positive appeal outcome is adjudged to be significantly uncertain, in which event the impact of an amendment of tax obligations is recognized based on the assessment amounts appealed.

In income tax calculation, the Company recognizes revenue from Disparity of Selling Price in the amount of the value of the receivables before adjusting for fair value (Note 9a). Difference in value of receivables with fair value is recognized as deferred tax assets. Recovery from adjusting the fair value of receivables in subsequent years will be recorded as interest income. The interest income is not recognized as an object of income tax but as a reversal of previously deferred tax assets.

Deferred Tax

Deferred tax is recognized using the liability method for temporary differences between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date.

Deferred tax liabilities are recognized for all taxable temporary differences, except:

i. deferred tax liabilities that occur from the initial recognition of goodwill or from assets or liabilities from transactions that are not business combination transactions, and at the time of the transaction do not affect accounting profit and taxable/taxable income;
ii. from taxable temporary differences in investments in subsidiaries, associated companies and interests in joint arrangements, which when reversed can be controlled and it is probable that the temporary differences will not be reversed in the near future.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

u. Income tax (continued)

Deferred Tax (continued)

Deferred tax assets are recognized for all deductible temporary differences, unused tax credit balances and accumulated unused tax losses. Deferred tax assets are recognized to the extent that it is probable that the amount of taxable income will be sufficient to be compensated with deductible temporary differences, and the application of unused tax credits and taxable accumulated losses that can be used, except:

i. if deferred tax assets arise from the initial recognition of an asset or liability in a transaction that is not a business combination transaction and does not affect the accounting profit or taxable income/tax loss; or

ii. from temporary differences that can be deducted from invxestments in subsidiaries, associated companies and interests in joint arrangements, deferred tax assets are only recognized if it is probable that the temporary differences will not be reversed in the near future and taxable profits can be compensated by the temporary difference.

The carrying amount of deferred tax assets is reviewed at each reporting date and is reduced if the taxable income may not be sufficient to compensate for part or all of the benefits of the deferred tax asset. Deferred tax assets that are not recognized are reviewed at each reporting date and will be recognized if it is probable that future taxable profits will be available for recovery.

Deferred tax assets and liabilities are measured using the tax rate that is expected to apply to the year when the asset is recovered or the liability is settled based on the tax rates and applicable tax regulations or substantively enacted at the reporting date.

Deferred tax assets and liabilities related to PSC activities are calculated using the tax rate that applies to the effective date of the PSC or renewal date or date of change in the PSC.

Deferred tax on goods recognized outside of profit or loss is recognized outside of profit or loss. Estimated deferred tax is recognized to correlate with underlying transactions in both the OCI and directly in equity.

Value Added Tax ("VAT")

Revenues, expenses and assets are recognized net of the amount of VAT except:

i. VAT that arises from the purchase of an asset or service that cannot be credited by the tax office, in which case the VAT is recognized as part of the acquisition cost of the asset or as part of the items applied for expenses; and

ii. Receivables and payables presented include the amount of VAT.

VAT on subsidies and/or Disparity of Selling Price will be recorded by the Company when submitting payments for subsidies and/or price differences to the Directorate General of Budget.

Final Tax

In accordance with taxation regulations in Indonesia, final tax is applied to the gross value of the transactions, even when the parties carrying the transactions recognizing losses.

Referring to revised PSAK No. 46 (Revised 2014), final tax is no longer governed by PSAK No. 46. Therefore, the Company has decided to present all of the final tax arising from interest income which subject to final tax as separate line item.

v. Segment information

An operating segment is a component of an enterprise:
a. that engages in business activities from which it may earn revenues and incur expenses (including revenue and expenses related to the transactions with different components within the same entity);
b. whose operating results are regularly reviewed by the enterprise's chief operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and
c. for which discrete financial information is available.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

w. Impairment of non-financial assets

Assets that have an indefinite useful life - for example, goodwill or intangible assets not ready for use - are not subject to amortization and are tested annually for impairment.

Assets that are subject to amortization or depreciation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognized in the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (Cash-Generating Units or CGUs). Non-financial assets other than goodwill that suffer an impairment are reviewed for possible reversal of the impairment at each reporting date.

x. Bond issue costs

Bond issue costs are presented as a deduction from bonds payable as part of non-current liabilities in the consolidated statement of financial position.

The difference between net proceeds and nominal value represents a discount which is amortized using the EIR method over the term of the bond.

y. Joint arrangements

The Group is a party to a joint arrangement when there is a contractual arrangement that confers joint control over the relevant activities of the arrangement to the Group and at least one other party. Joint control is assessed under the same principles as control over subsidiaries.

The Group classifies its interests in joint arrangements as either:
a. Joint ventures: where the Group has rights to only the net assets of the joint arrangement.
b. Joint operations: where the Group has both the rights to assets and obligations for the liabilities of the joint arrangement.

In assessing the classification of interests in joint arrangements, the Group considers:
a. the structure of the joint arrangement;
b. the legal form of joint arrangements structured through a separate vehicle;
c. the contractual terms of the joint arrangement agreement;
d. any other facts and circumstances (including any other contractual arrangements).

The Group recognizes its interest in joint venture using equity method.

Any premium paid for an investment in a joint venture above the fair value of the Group's share of the identifiable assets, liabilities and contingent liabilities acquired is capitalized and included in the carrying amount of the investment in joint venture. Where there is objective evidence that the investment in a joint venture has been impaired, the carrying amount of the investment is tested for impairment in the same way as non-financial assets.

The Group accounts for its interests in joint operations by recognizing its share of assets, liabilities, revenues and expenses in accordance with its contractually conferred rights and obligations.

z. Share capital

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issuance of new shares are shown in equity as a deduction, net of tax, from the proceeds.

aa. Dividends

Dividend distribution to the shareholders is recognized as a liability and deducted from equity in the Group consolidated financial statements in the period in which the dividends are declared.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

ab. Borrowing costs

Borrowing costs are interest and exchange differences on foreign currency denominated borrowings and other costs (amortization of discounts/premiums on borrowings, etc) incurred in connection with the borrowing of funds.

Borrowing costs which are directly attributable to the acquisition, construction, or production of qualifying assets are capitalized as part of the acquisition cost of the qualifying assets. Other borrowing costs are recognized as expense in the period in which they are incurred.

The Group ceases capitalizing borrowing costs when substantially all the activities necessary to prepare the qualifying asset for its intended use or sale are complete.

ac. Fair value measurement

The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:
- in the principal market for the asset or liability or;
- in the absence of a principal market, in the most advantageous market for the asset or liability.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy as follows:
- Level 1 - quoted (unadjusted) market prices in active markets for identical assets or liabilities;
- Level 2 - valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable; and
- Level 3 - valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

ad. Completion of consolidated financial statements

The company's management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Indonesian Financial Accounting Standards, which were completed and authorized for issuance by the Board of Directors of the Company on December 17, 2019.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS

In the application of the Group's accounting policies, which are described in Note 2 to the consolidated financial statements, management is required to make estimates, judgements and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources.

These estimates, judgements and assumptions are based on historical experience and other factors that are considered to be relevant.

a. Judgements

The following judgements are made by management in the process of applying the Group's accounting policies:

i. Exploration and evaluation expenditures

The Group's accounting policies for exploration and evaluation expenditures result in certain items of expenditure being capitalized for an area of interest where it is considered likely to be recoverable by future exploitation or sale or where the activities have not reached a stage which permits a reasonable assessment of the existence of reserves. This policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

a. Judgements (continued)

ii. Development expenditures

Development activities commence after a project is sanctioned by the appropriate level of management. Judgement is applied by management in determining when a project is economically viable.

iii. Uncertain tax exposure

Based on the tax regulations currently enacted, the management assessed if the amounts recorded under claim for tax refund are recoverable and refundable from the Tax Office. Further, the management also assessed possible liability that might arise from the tax assessment under objection.

Significant judgment is involved in determining the provision for corporate income tax and other taxes on certain transactions. Uncertainties exist with respect to the interpretation of complex tax regulations and the amount and timing of future taxable income. The Group makes an analysis of all tax positions related to income taxes to determine if a tax liability for unrecognized tax benefit should be recognized.

iv. Recognition of disparity of selling price of JBT diesel fuel and JBKP premium

The Presidential Regulation No. 43 Year 2018 dated May 25, 2018 regarding Amendment to Presidential Regulation No. 191 Year 2014 regarding Provision, Distribution and HJE Fuel Oil states that, in the event, based on the results of the audit by the Audit Board of the Republic of Indonesia (BPK), there are excess and/or shortfall of revenue of an assigned business entity in 1 (one) fiscal year, as a result of Government's stipulated sellling price of fuel oil, the Minister of Finance ("MoF"), in coordination with the Minister of Energy and Mineral Resources (the "MoEMR") and the Minister of State-Owned Enterprises (the "MoSOE"), will establish a policy regarding settlement of excess and/or shortfall of revenue of such business entity.

Management believes that it is appropriate to recognize excess and/or shortfall of revenue from the Disparity of Selling Price in the period when sales of JBT Diesel Fuel and JBKP Premium occur and that the settlement and/or collectability of such Disparity of Selling Price is certain when (i) the Company has transferred all risks and rewards of JBT Diesel Fuel and JBKP Premium to consumers across Indonesia, (ii) the Company retains neither continuing managerial involvement and effective control over JBT Diesel Fuel and JBKP Premium when the sale occurred and (iii) the BPK's audit results on the Disparity of Selling Price are received by the Company and, in respect of the shortfall of revenue from the Disparity of Selling Price, the collectabilty of revenue from the Disparity of Selling Price is certain when the Decision Letter from the Minister of Finance ("Decision Letter") has been received by the Company prior to the completion of the financial statements.

Such excess and/or shortfall of revenue from the Disparity of Selling Price is recorded as revenue from other operating activities because it is part of the Company's operations.

b. Estimates and assumptions

The key assumptions regarding the future and other key sources of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial period are disclosed below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared.

i. Impairment of non-financial assets

In accordance with the Group's accounting policy, each asset or CGU is evaluated every reporting period to determine whether there are any indications of impairment.

The determination of fair value and value in use requires management to make estimates and assumptions about expected production and sales volumes, commodity prices (considering current and historical prices, price trends and related factors), reserves, operating costs, decommissioning and site restoration cost, and future capital expenditure. These estimates and assumptions are subject to risk and uncertainty; hence there is a possibility that changes in circumstances will alter these projections, which may have an impact on the recoverable amount of the assets.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

b. Estimates and assumptions (continued)

ii. Reserves estimates

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves include:

(i) proved developed reserves: amounts of hydrocarbons that are expected to be retrieved through existing wells, facilities and operating methods; and
(ii) proved undeveloped reserves: amounts of hydrocarbons that are expected to be retrieved following new drilling, facilities and operating methods.

The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables such as: the quality of available geological, technical and economic data, results of drilling, testing and production after the date of the estimates, the production performance of the reservoirs, production techniques, projecting future rates of production, the anticipated cost and timing of development expenditures, the availability for commercial market, anticipated commodity prices and exchange rates.

As the economic assumptions used to estimate reserves change from year to year, and additional geological data are generated during the course of operations, estimates of reserves may change from year to year. Changes in reported reserves may affect the Group's financial results and financial position in a number of ways, including:

i. Depreciation and amortization which are determined on a unit of production basis, or where the useful economic lives of assets change.
ii. Decommissioning, site restoration and environmental provision may change where changes in estimated reserves affect expectations about the timing or cost of these activities.
iii. The carrying value of deferred tax assets/liabilities may change due to changes in estimates of the likely recovery of the tax benefits.

The Group has established proven reserves based on the principle of Petroleum Resources Management System ("PRMS") 2018, starting for January 1, 2019 (Previously based on PRMS 2007). The characteristics of the estimation uncertainty of natural reservoirs of oil and gas reserve may lead to changes in the estimated reserves due to the additional data obtained by the Group.

iii. Oil and gas properties

The Group applies the successful efforts method for its oil and natural gas exploration and evaluation activities.

For exploration and exploratory-type stratigraphic test wells, costs directly associated with the drilling of those wells are initially capitalized as assets under construction within oil and gas properties, pending determination of whether potentially economically viable oil and gas reserves have been discovered by the drilling effort.

Such estimates and assumptions may change as new information becomes available. If the well does not discover potentially economically viable oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense.

iv. Provision for the impairment of loans and receivables

Provision for the impairment of receivables is maintained at a level considered adequate to provide for potentially uncollectible receivables. The Group assesses specifically at each balance sheet date whether there is objective evidence that a financial asset is impaired (uncollectible).

The level of provision is based on past collection experience and other factors that may affect collectability.

Loans and receivables write-offs are based on management's decision that the financial assets are uncollectible or cannot be realized regardless of the actions taken.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

b. Estimates and Assumptions (continued)

v. Due from the Government

The Group recognizes amounts due from the Government for cost subsidies for certain fuel ("BBM") products and 3 kg LPG cylinders and marketing fees in relation to the Government's share of crude oil, natural gas and LNG. The Group makes an estimation of the amount due from the Government based on the actual delivery volume parameter and rates based on government regulations. The amount of subsidies is subject to audit and approval by the Audit Board of the Republic of Indonesia ("BPK"). The actual results may be different from the amounts recognized.

vi. Depreciation, estimate of residual values and useful lives of fixed assets

The useful lives of the Group's investment properties and fixed assets are estimated based on the period over which the asset is expected to be available for use. Such estimation is based on a collective assessment of similar businesses, internal technical evaluations and experience with similar assets.

vii. Deferred tax assets

Deferred tax assets are recognized only where it is considered more likely than not that they will be recovered, which is dependent on the generation of sufficient future taxable profits.

viii. Provision for decommissioning and site restoration

The Group is obliged to carry out decommissioning of oil and gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations faced by the Group relate to the plugging and abandonment of wells and the removal and disposal of oil and gas platforms and pipelines in its contract area.

The Group recognizes provision for assets decommissioning and site restoration ("ASR") for all assets in the Group's PSC areas, except for certain subsidiaries as disclosed in Note 49n.

Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the related asset and could have a material impact on the Group's consolidated financial statements.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST

The Group has acquired and added participating interest through acquisition transactions or acquisitions of terminated blocks. The acquisition transactions were made in accordance with the Group's strategy to develop its upstream business i.e. to increase oil, gas and geothermal production and reserves, and to expand the business overseas. The summary of the Group's transactions during 2016 until September 30, 2019 is as follows:

Acquisition of shares	Working area	Area	Percentage of participation	Production	Sub-Holding
Share acquisition Etablissements Maurel et Prom SA (M&P)	France	Canada, Colombia, Nigeria, Gabon, France, Italy, Tanzania, Namibia and Myanmar	72.65%	Oil and gas	PT Pertamina Internasional Eksplorasi dan Produksi

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

Acquisition of working area and interest	Working area	Area	Effective date of contract	Expiry date of contract	Percentage of Participation	Production	Contract period	Sub-holding
Kampar Block	Kampar Block	Riau	01/01/2016	31/12/2035	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
East Ambalat Block	East Ambalat Block	East Kalimantan	25/05/2016	24/05/2046	100%	Oil and gas	30 years	PT Pertamina Hulu Energi
Offshore North West Java Block	Offshore North West Java Block	North West Java	19/01/2017*	18/01/2037	90%	Oil and gas	20 years	PT Pertamina Hulu Energi
Geothermal Gunung Lawu	Gunung Lawu	Central Java and East Java	30/01/2017	29/01/2054	100%	Geothermal	37 years	PT Pertamina Geothermal Energy and PT Pertamina Hulu Energi
Jambaran Tiung Biru Unitization Field	EP Block and Cepu Block	Central Java-East Java	01/01/2018**	16/09/2035	91.93%	Gas	Until the end of PEPC's PSC	PT Pertamina EP Cepu
Attaka (Unitization) Field	Attaka***	East Kalimantan	01/01/2018	24/10/2018	100%	Oil and gas	10 months	PT Pertamina Hulu Indonesia
Mahakam Block	Mahakam	East Kalimantan	01/01/2018	31/12/2037	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Geothermal Seulawah Agam	Seulawah Agam	Aceh	09/04/2018	08/04/2055	75%	Geothermal	37 years	PT Pertamina Geothermal Energy
Tuban Block	Tuban Block	East Java	20/05/2018*	19/05/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Ogan Komering Block	Ogan Komering Block	South Sumatera	20/05/2018*	19/05/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Sukowati Unitization Field	Sukowati	Tuban	20/05/2018	-	100%	-	20 years	PT Pertamina EP
Sanga Sanga Block	Sanga Sanga Block	East Kalimantan	08/08/2018*	07/08/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Offshore Southeast Sumatera ("OSES") Block	SES Block	South East Sumatera	06/09/2018*	05/09/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
North Sumatera Offshore ("NSO") Block	NSO Block	North Sumatera	17/10/2018*	16/10/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
East Kalimantan and Attaka Block	East Kalimantan and Attaka Block***	East Kalimantan	25/10/2018*	24/10/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Jambi Merang Block	Jambi Merang Block	South Sumatera	10/02/2019*	09/02/2039	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Raja/Pendopo Block	Raja/Pendopo Block	South Sumatera	06/07/2019*	05/07/2039	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Salawati Block	Salawati Block	Papua	23/04/2020*	22/04/2040	30%	Oil and gas	20 years	PT Pertamina Hulu Energi
Kepala Burung Block	Kepala Burung Block	Papua	15/10/2020*	14/10/2040	30%	Oil and gas	20 years	PT Pertamina Hulu Energi
Maratua Block	Maratua Block	North Kalimantan & East Kalimantan	18/02/2019*	17/02/2049	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Rokan Block	Rokan Block	Central Sumatera	09/08/2021	08/08/2041	100%	Oil and gas	20 years	Pertamina Hulu Rokan

* Note 4d
** Note 4f
*** Effective October 2018, Attaka Block was merged into East Kalimantan Block

a. Establishment of State-owned Oil and Gas Holding Enterprise

On December 30, 2016, the Government of Indonesia ("GOI") issued Government Regulation ("PP") No. 72/2016 as a revision to PP No. 44/2005 regarding Procedures and Administration of State Capital Investment in State-Owned Enterprises and Limited Company. This regulation is the legal basis for the establishment of state-owned holding enterprise that is being deliberated by the GOI.

On February 28, 2018, the GOI issued PP No. 6/2018 regarding Additional State Capital Investment in the Company. This regulation is to increase the GOI paid-up capital in the Company by transfering 13,809,038,755 (full amount) B series shares of PT Perusahaan Gas Negara Tbk ("PGN")'s owned by the GOI, which represents 56.96% of total PGN shares, to the Company.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

a. Establishment of State-owned Oil and Gas Holding Enterprise (continued)

On March 28, 2018, the Ministry of Finance issued Decree No. 286/KMK.06/2018 regarding the determination of the value of additional State capital participation in the Company's share capital. The decree stipulates that the value of additional State capital participation in the Company's share capital is Rp38,136,346,046,696 (full amount).

On April 11, 2018, the Minister of State-Owned Enterprises ("MoSOE") issued Letter No. S-216/MBU/2018 to approve the transfer of 56.96% B series shares of PGN and additional State capital investment in the Company amounting to Rp38,136,346,046,696 (full amount). On the same date, the MoSOE issued Letter No. S-217/MBU/04/2018 to increase the Company's authorized share capital from Rp200 trillion to Rp600 trillion with nominal amount of Rp1,000,000 (full amount) per share. This letter also approved additional issued and paid-up capital of the Company by 38,136,347 shares or amounting to Rp38,136,346,046,696 (full amount) or equivalent to US$2,774,157.

Further, on April 11, 2018, the MoSOE and the Company entered into an agreement regarding the transfer of Government rights at PGN to the Company, to increase the state capital participation in the Company.

On April 13, 2018, the Minister of Law and Human Rights issued Letter No. AHU-0008395.AH.01.02. 2018 regarding Approval of Changes in PT Pertamina (Persero) Articles of Association. It is stipulated that changes to Pertamina's Article of Association in relation to the total issued and paid-up shares of Rp171,227,044,000,000 (full amount) or equivalent to US$16,191,204 has been approved.

On May 9, 2018, the MoSOE, as the holder of PGN's A Series Dwiwarna shares, issued a Power of attorney letter in relation to transfer of rights and authority of A series shares of PGN share to the Company as the majority holder of B series shares of PGN shares. This letter is to provide PT Pertamina (Persero) control over PGN.

The above transaction is recorded in accordance with SFAS 38 (Revised 2012) "Business Combinations of Entities Under Common Control".

The following is a summary of PGN's financial information at the acquisition date:

	Book value
ASSETS	
Current assets	2,021,879
Non-current assets	4,442,988
Total assets	**6,464,867**
LIABILITIES	
Current liabilities	553,560
Non-current liabilities	2,649,167
Total liabilities	**3,202,727**
EQUITY	
Share capital	344,019
Other paid-in capital	284,339
Retained earnings	
Appropriated	2,427,854
Unappropriated	223,501
Other components of equity	(36,868)
Total equity attributable to owners of the parent entity	**3,242,845**
B series shares transfer representing 56.96% ownership of interest	(1,847,125)
Consideration amount	2,774,157
Additional paid-in capital	**927,032**

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

a. Establishment of State-owned Oil and Gas Holding Enterprise (continued)

Based on the amendment and restatement of the share purchase agreement between the Company and PGN dated December 28, 2018, PGN officially acquired 51% (or 2,591,099 shares) of PT Pertamina Gas ("Pertagas") owned by the Company with total transaction value of Rp20.18 trillion, equivalent to US$1,351,955. With the acquisition of these shares, PGN effectively owned 51% of Pertagas shares including Pertagas's 5 subsidiaries, PT Pertagas Niaga, PT Perta Arun Gas, PT Perta Daya Gas, PT Perta-Samtan Gas, and PT Perta Kalimantan Gas. Pursuant to this transaction, the Company's effective ownership of Pertagas decreased from 100% to 78.05%.

b. Control over PT Nusantara Regas ("Regas")

The Company and PGN own 60% and 40% ownership of interest in Regas, respectively. As a result of the establishment of state-owned oil and gas enterprise, the Company indirectly owns 82.78% ownership of interest. The management conclude that the Company has majority vote over Regas to direct relevant activities. Therefore, the Company has control over Regas and starting April 11, 2018, the Company consolidates Regas financial statements.

The following is a summary of Regas' financial information at the date when the Company obtains control.

	Book value
ASSETS	
Current assets	233,935
Non-current assets	56,116
Total Assets	**290,051**
LIABILITIES	
Current liabilities	20,769
Non-current liabilities	12,707
Total Liabilities	**33,476**
EQUITY	
Share capital	145,589
Retained earnings	
Appropriated	43,129
Unappropriated	68,026
Other components of equity	(169)
Total Equity	**256,575**

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares

M&P is a listed company in the Paris Stock Exchange which has the following production assets: Ezanga Block in Gabon (as the operator with Working Interest ("WI") of 80%); Mnazi Bay Field in Tanzania (as the operator with WI of 48.06%); and owns 20.46% shares in Seplat (a Company listed in Lagos Stock Exchange, Nigeria and London Stock Exchange, England) which has several production assets in Nigeria. M&P also has exploration assets and undeveloped discovery areas located in Italy, France, Myanmar, Canada, Tanzania, Gabon, Colombia, and Namibia.

On August 25, 2016, the Group through PT Pertamina Internasional Eksplorasi dan Produksi ("PIEP"), a wholly owned subsidiary of the Company, purchased all of the shares held by Pacifico SA in M&P representing 47,916,026 shares corresponding to 24.53% shares ownership in M&P. PIEP had increased its shares ownership through a tender offer with the same terms and conditions to all M&P's shares.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares (continued)

The process of step-up acquisition through Voluntary Tender Offer is conducted in two stages. The first phase was completed on January 25, 2017 and the payment was made on February 1, 2017, after which PIEP owns 64.46% of M&P shares and 63.35% of voting rights, resulting in a "change of control" of M&P. The second phase of voluntary tender offer was completed on February 15, 2017 and the payment was executed on February 22, 2017, from that date, PIEP becomes the holder of:

1. 141,911,939 M&P shares, representing 72.65% of share capital and 71.39% of the voting rights in M&P;
2. 14,641,233 ORNANE 2019 bonds, which represent 99.88% of the outstanding bonds;
3. 10,435,331 ORNANE 2021 bonds, which represent 99.99% of the outstanding bonds.

On December 20, 2017, M&P redeemed all ORNANE 2019 and ORNANE 2021 bonds owned by PIEP and paid in cash the nominal amount of the bonds and interest thereon, so that PIEP no longer holds ORNANE 2019 and ORNANE 2021 bonds.

Following the completion of the shares acquisition, PIEP became the majority shareholder and has control over M&P.

Calculation of the fair value of identified assets and liabilities taken over by PIEP was completed on December 31, 2017. Fair value adjustments mainly come from the valuation of reserves and sources of oil acquired, for exploration and/or production assets, in Gabon, Nigeria, Tanzania, and Venezuela.

The fair value of identified assets and liabilities arising from the acquisition of M&P are as follows:

	Amount
ASSETS	
Financial assets	353,653
Inventories	9,678
Prepaid taxes	70,844
Deferred tax assets	35,096
Long-term investments	94,697
Oil and gas properties	1,723,322
Other non-current assets	85,318
Total assets	**2,372,608**
LIABILITIES	
Financial liabilities	913,431
Tax payables	39,801
Deferred tax liabilities	371,004
Employee benefit liabilities	1,143
Provision for decommissioning and site restoration	41,110
Total liabilities	**1,366,489**
Net assets at the acquisition date (include deferred tax assets and liabilities)	**1,006,119**
Excess of book value over fair value	9,600
Fair value of net assets	1,015,719
Interest acquired	72.65%
Fair value of net assets acquired	737,920
Foreign currency translation	28,337
Bargain purchase	(54,130)
Purchase consideration through cash	**712,127**

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares (continued)

The fair value of identified assets and liabilities arising from the acquisition of M&P are as follows: (continued)

	Amount
Below is the cash flow analysis from the acquisition of M&P:	
Transaction value of the acquisition	712,127
Less: Cash from M&P	(203,230)
Net cash flow to acquire control	**508,897**

The bargain purchase amount also include gain on remeasurement of the previously held equity interest amounting to US$42,658.

On November 5, 2018, M&P entered into an agreement with Rockover Energy Limited ("Rockover") to acquire the deferred payments owned by Rockover for a consideration of US$10.75 million (full amount) to be paid in cash and issuance of 5,373,209 new M&P shares.

On December 12, 2018, the extraordinary general meeting of M&P shareholders approved the delegation of authority relating to the capital increase for the purpose of transaction with Rockover to the Board of Directors. On December 14, 2018, the Board of Directors of M&P implemented this delegation of authority and decided to carry out the capital increase for a total nominal amount of €4,137,371 (full amount) through issuance of 5,373,209 new shares with a par value of €0.77 (full amount) each and a unit subscription price of €5,182 (full amount) each. Pursuant to the completion of the capital increase, Rockover holds 2.68% of M&P's share capital and resulted in dilution of the Company's percentage of ownership in M&P from 72.65% to 70.75%.

In October 2018, Maurel & Prom Venezuela SLU ("M&P Venezuela"), a wholly owned subsidiary of M&P, signed a Share Sale and Purchase Agreement ("SSPA") for the acquisition of Shell Exploration and Production Investments B.V. ("Shell")'s 40% interest as "Shareholder B" in Mixed Company. Mixed Company operates the Urdaneta West field in Lake Maracaibo, Venezuela. Petróleos de Venezuela S.A. ("PDVSA"), through its wholly owned subsidiaries Corporación Venezolana del Petróleo ("CVP") and PDVSA Social ("PDVSAS") - collectively referred to as "Shareholder A", own the remaining 60% stake of the Mixed Company.

On December 3, 2018, pursuant to the approval from the Ministry of Petroleum of Venezuela, M&P Venezuela effectively acquired 40% shares from Shell in Mixed Company with total consideration payment for the acquisition of €70 million, which will be settled as follows:
1. €47 million have been paid at closing of the transaction in December 2018, and
2. €23 million to be in December 2019, 1 (one) year after the closing of the transaction.

d. Gross split contract ("Gross Split")

On January 13, 2017, the regulation of the Minister of Energy and Mineral Resources ("MoEMR") No. 08/2017 regarding principles of the Production Sharing Contract without Cost Recovery Mechanism, also known as Gross Split PSC, was issued. Following is the Group's Gross Split PSC interests.

Working Area	Effective date of contract	Expiry date of contract	Percentage of participation	Contract period	Sub-holding
East Sepinggan Block	20/07/2012	19/07/2042	15%	30 years	PT Pertamina Hulu Energi
Offshore North West Java block	19/01/2017	18/01/2037	90%	20 years	PT Pertamina Hulu Energi
Tuban Block	20/05/2018	19/05/2038	100%	20 years	PT Pertamina Hulu Energi

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

d. Gross split contract ("Gross Split") (continued)

Working Area	Effective date of contract	Expiry date of contract	Percentage of participation	Contract period	Sub-holding
Ogan Komering Block	20/05/2018	19/05/2038	100%	20 years	PT Pertamina Hulu Energi
Offshore Southeast Sumatera Block	6/09/2018	05/09/2038	100%	20 years	PT Pertamina Hulu Energi
Sanga Sanga Block	08/08/2018	07/08/2038	100%	20 years	PT Pertamina Hulu Indonesia
East Kalimantan and Attaka Block	25/10/2018	24/10/2038	100%	20 years	PT Pertamina Hulu Indonesia
NSO Block	17/10/2018	16/10/2038	100%	20 years	PT Pertamina Hulu Energi
Jambi Merang Block	10/02/2019	09/02/2039	100%	20 years	PT Pertamina Hulu Energi
Maratua Block	18/02/2019	17/02/2049	100%	30 years	PT Pertamina Hulu Energi
Raja Pendopo Block	06/07/2019	06/07/2039	100%	20 years	PT Pertamina Hulu Energi
West Ganal PSC	26/01/2020	25/01/2050	30%	30 years	PT Pertamina Hulu Indonesia
Salawati Block	23/04/2020	22/04/2040	20%	20 years	PT Pertamina Hulu Energi
Kepala Burung Block	15/10/2020	14/10/2040	30%	20 years	PT Pertamina Hulu Energi
Rokan PSC	09/08/2021	08/08/2041	100%	20 years	Pertamina Hulu Rokan

e. Mahakam production sharing contract

In accordance with MoEMR Letter No. 2793/13/ME.M/2015 regarding *Pengelolaan Wilayah Kerja ("WK") Mahakam Pasca 2017*, the Company is appointed as the contractor and operator of the Mahakam Contract Area (previous contractors are Total E&P Indonesie and INPEX Corporation). To manage such working area, the Company, through PT Pertamina Hulu Indonesia ("PHI") established PT PHM.

Mahakam PSC was signed on December 29, 2015 by SKK Migas and PHM with effective date on January 1, 2018. The PSC uses the concept of production sharing, but has introduced a new sliding scale approach to calculate the contractor entitlement based on Revenue Over Costs ("R/C") ratio.

On October 25, 2016, the Amendment of Mahakam PSC was adopted, adding some important points, including the certainty of the costs incurred by PHM after the date of signing the contract but before the effective date of the contract. These costs will be included in cost recovery as operating cost after the effective date of contract.

On April 20, 2018, the second amendment of Mahakam PSC was signed, adding some important points, including the addition of Tengah working area into Mahakam working area. This amendment was effective on October 5, 2018.

The PSC term refers to PP No. 79 Year 2010, where the assume and discharge mechanism for taxes that became incentives for PSC Contractors are treated as part of the cost to be recovered through the cost recovery mechanism.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

e. Mahakam production sharing contract (continued)

The provisions are as follows:

- Crude oil and natural gas production sharing

The sharing of oil production between PHM and the Government is 23.5294% and 76.4706%, respectively, while sharing of gas production is 47.0588% and 52.9412% for the first year of contract. The R/C factor in effect in the first year is 1.3 as stipulated in the PSC. Oil and gas production sharing for subsequent years are listed in the table below with R/C factor at the end of previous year.

The R/C factor itself is the contractor's cumulative revenue from the date of signing the contract divided by the contractor's cumulative cost since the signing of the contract.

R/C	Tax Rate	Gross Contractor Share		Net Contractor Share	
		Oil	Gas	Oil	Gas
0 – 1	36.25%	31.3726%	54.9020%	20%	35%
0 – 1.2	36.25%	27.4510%	50.9804%	18%	33%
1.2 – 1.4	36.25%	23.5294%	47.0588%	15%	30%
1.4 – 1.6	36.25%	19.6078%	43.1373%	12%	28%
> 1.6	36.25%	15.6863%	39.2157%	10%	25%

- First Tranche Petroleum (“FTP”)

The Government and PHM are entitled to receive an amount equal to 20% of the total production of oil and gas each year before any deduction for recovery of operating costs and investment credit. FTP is shared between the Government and PHM in accordance with the entitlements to oil and gas production.

Total capital expenditure and operating expenses related to the delivery of the Mahakam Block as of December 31, 2017 are US$99,780 and US$63,666, respectively, recorded as oil and gas assets and deferred charges which can only be submitted for cost recovery starting January 1, 2018.

As at the authorization date of these consolidated financial statements, the scheme for utilization of assets previously utilized by the predecessor Mahakam PSC contractors has not yet been determined by the Government, in this case the Directorate General of State Assets and MoEMR.

On April 20, 2018, the second amendment of Mahakam PSC was signed adding some important points, including the addition of Tengah working area into Mahakam working area. This amendment became effective on October 5, 2018.

f. Addition of 41.37% of PT Pertamina EP Cepu’s (“PEPC”) participating interest in Jambaran-Tiung Biru (“JTB”) unitization field

Effective November 3, 2017, PEPC acquired an additional 41.37% participating interest in the JTB unitization field previously held by ExxonMobil Cepu Limited and Ampolex (Cepu) Pte. Ltd., increasing the Company’s participating interest in JTB unitization field to 82.74%. The other contractors in JTB field are PT Pertamina EP with 8.06% and Several Region Owned Enterprise (“BUMD”) with 9.19%.

Through Letter No. 001/KETUA-BKS/XI/2017 dated November 17, 2017 and Letter No. 004/KETUA-BKS/XII/2017 dated December 19, 2017, Cooperating Body Participating Interest Block (“PI BKS”) Cepu conveyed the resignation of 4 Members of the PI BKS Cepu Block namely PT Asri Dharma Sejahtera (“ADS”), PT Sarana Patra Hulu Cepu (“SPHC”), PT Blora Patragas Hulu (“BPH”), PT Petrogas Jatim Utama Cendana (“PJUC”), which the four members stated they would not participate in the development of the Jambaran-Tiung Biru Field Gas project (“JTB”) starting January 1, 2018.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

f. Addition of 41.37% of PT Pertamina EP Cepu's ("PEPC") participating interest in Jambaran-Tiung Biru ("JTB") unitization field (continued)

Effective January 1, 2018, the Company added a 9.19% participating interest in the JTB unitization field previously owned by the BKS (ADS, SPHC, BPH, PJUC) so that the Company's participating interest in the JTB unitization field becomes 91.93%. Payment for this acquisitions totaled to US$16,764. The acquisitions of this participating interests was recorded as an additional oil and gas assets.

g. Establishment of PT Pertamina Hulu Rokan ("PHR")

Based on the Decree of the Minister of Energy and Mineral Resources No. 1923K/10/MEM/2018 dated August 6, 2018 regarding Agreement on Management of Establishment of Principal Forms and Conditions (Terms and Conditions) of Cooperation Contracts in Rokan Work Areas, one of the requirements that must be fulfilled by Pertamina includes preparing a new subsidiary, signature bonus and payment of work commitments (Note 4d).

On December 20, 2018, PT Pertamina Hulu Rokan was established based on Notarial Deed No.13 dated December 20, 2018 from Lenny Janis Ishak, S.H. Deed of establishment of PHR was approved by the Minister of Law and Human Rights through Letter No. AHU-0061348.AH.01.01.2018 dated December 21, 2018. PHR will manage the Rokan Block from 2021 to 2041. Total authorized capital of PHR is US$3,140,000 with paid-in capital of US$785,000. The paid-up capital was used to pay the signing bonus to the Government of Indonesia in the amount of US$783,980 on December 21, 2018, and is to be used as working capital during the first year of managing its working area.

h. Addition of 20% of PT Pertamina EP's participating interest in Sukowati unitization field

Based on SKK Migas letter No. SRT-0493/SKKMA0000/2018/S1 dated June 25, 2018 regarding the determination of the new unitization operator of Sukowati Field, CPA Mudi production facilities and Cintanatomas FSO, PT Pertamina EP was appointed as the new operator of the Sukowati Field.

Based on a joint agreement regarding the management of Sukowati Field unitization, the operation of the CPA Mudi production facility and Cintanatomas FSO dated May 16, 2018 between PT Pertamina EP and PT Pertamina Hulu Energi Tuban East Java, it was agreed that PT Pertamina EP has an interest participation unit of 100% (Note 43c).

i. Temporary cooperation contract of Attaka working area

The Temporary Cooperation Contract ("TCC") was made and signed on November 2, 2017 by SKK Migas and PT Pertamina Hulu Attaka, explained all terms, conditions, rights and obligations, of and pursuant to the ex-Attaka PSC shall be applicable to the TCC from the date of January 1, 2018 until October 24, 2018. Effective from October 25, 2018, the Attaka working area was combined into Sanga-Sanga PSC.

j. Decrease in the percentage of ownership of the Company at PT Asuransi Tugu Pratama Indonesia Tbk (formerly PT Tugu Pratama Indonesia)

On May 28, 2018, ATPI became a public company by issuing 177,777,800 shares of new shares. As a result, the percentage of the Company's ownership in ATPI decreased from 65.0% to 58.5%. This reduction in the percentage of ownership does not result in a loss of Company's control in ATPI. Thus, the impact of this transaction amounting to US$20,551 is calculated as an equity transaction and recorded in the difference account of transactions with non-controlling interests.

k. Addendum to the agreement on the transfer and management of the ONWJ Block PSC

On February 6, 2019, PHE ONWJ and PT Migas Hulu Jabar ONWJ ("MUJ ONWJ") signed an addendum on the transfer agreement and management of 10% working interest at in the ONWJ PSC. MUJ's share of production from the ONWJ PSC, less its share of expenses in the PSC from January 19, 2017 to December 31, 2018 is US$16,303. Settlement of such amount has been made by PHE ONWJ to MUJ on February 8, 2019.

Starting from the date of the transfer, payments of MUJ ONWJ's share of the production is made on a monthly basis by PHE ONWJ after deducting MUJ ONWJ's share of the ONWJ PSC's operating costs and other obligations in accordance with the PSC.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

k. Addendum to the agreement on the transfer and management of the ONWJ Block PSC (continued)

In the event MUJ ONWJ's share of production in the current month is insufficient to cover MUJ ONWJ's share of operating costs, the cumulative underpayment will be carried over to the following months.

To ensure MUJ ONWJ's revenue, the production sharing and operating costs sharing with MUJ ONWJ is calculated based on provisional percentage for a full year, in accordance with the attachment to the addendum to the agreement. In the event in any year the cumulative operating costs which is payable by MUJ ONWJ to PHE ONWJ exceeds MUJ ONWJ's share of production, PHE ONWJ will pay US$1 (full amount) for each month in the following year.

l. Establishment of Pertamina International Marketing & Distribution Pte. Ltd. ("PIMD")

On August 5, 2019, based on Certificate Confirming Incorporation of Company No. 201925608H which was approved by Registrar Tan Yong Tat, Singapore, Pertamina International Marketing & Distribution was established with issued and paid-up shares of US$40,200. PIMD is engaged in the business of bunkers and logistics, and sales and distribution of fuel and LPG.

5. PURPOSE OF PREPARATION AND ISSUANCE OF CONSOLIDATED FINANCIAL STATEMENTS

These consolidated financial statements has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1993.

6. CASH AND CASH EQUIVALENTS

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Cash on hand	5,782	4,119	8,174	5,976
Cash in banks	5,404,623	5,045,496	2,770,229	3,011,880
Time deposits	2,684,374	4,062,697	3,631,424	3,703,712
Total	**8,094,779**	**9,112,312**	**6,409,827**	**6,721,568**

The details of cash and cash equivalents based on currency and by individual bank are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Cash on hand:				
Rupiah	3,901	3,128	7,515	5,205
US dollar	1,789	891	567	654
Others	92	100	92	117
Total cash on hand	**5,782**	**4,119**	**8,174**	**5,976**
Cash in banks				
US dollar:				
Government-related entities				
- PT Bank Negara Indonesia (Persero) Tbk. ("BNI")	1,556,330	844,933	636,281	627,690
- PT Bank Rakyat Indonesia (Persero) Tbk. ("BRI")	1,192,206	891,329	514,299	770,965
- PT Bank Mandiri (Persero) Tbk. ("Bank Mandiri")	622,695	581,752	562,533	722,517
- Other banks (each below US$10,000)	1,063	1,526	852	9,033

6. CASH AND CASH EQUIVALENTS (continued)

The details of cash and cash equivalents based on currency and by individual bank are as follows (continued):

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Cash in banks (continued)				
US dollar: (continued)				
Third parties				
- Crédit Agricole Corporate and Investment Bank ("Crédit Agricole CIB", previously "Calyon")	323,217	214,982	83,209	-
- Citibank, N.A. ("Citibank")	61,099	49,440	35,603	31,751
- J.P. Morgan Chase & Co.	35,675	16,130	-	-
- Sumitomo Mitsui Banking Corporation ("SMBC")	19,690	94,194	-	-
- PT Bank Sumitomo Mitsui Indonesia ("SMBC Indonesia")	2,162	2,515	32,293	42,645
- PT Bank Maybank Indonesia Tbk. ("Maybank" previously PT Bank Internasional Indonesia Tbk. "BII")	1,509	3,797	4,523	10,367
- Other banks (each below US$10,000)	12,419	9,735	14,291	26,128
Total US dollar accounts	**3,828,065**	**2,710,333**	**1,883,884**	**2,241,096**
Indonesian rupiah:				
Government-related entities				
- Bank Mandiri	524,250	651,073	270,785	277,654
- BRI	426,375	598,851	132,696	138,245
- BNI	310,626	547,355	185,568	93,136
- PT Bank Tabungan Negara (Persero) Tbk. ("BTN")	194,871	265,065	198,404	177,970
- PT Bank BRIsyariah Tbk. ("BRI Syariah")	21,998	48,692	9	6
- BNI Syariah	10,152	14,188	1,065	705
- Others banks (each below US$10,000)	5,973	9,745	2,664	4,106
Third parties				
- PT Bank Central Asia Tbk. ("BCA")	37,274	40,008	32,022	31,243
- Citibank	16,741	24,875	20,965	5,210
- Other banks (each below US$10,000)	10,636	17,866	15,622	16,048
Total Indonesian rupiah accounts	**1,558,896**	**2,217,718**	**859,800**	**744,323**
Euro:				
Government-related entities				
- BNI	7	8	554	4
- Bank Mandiri	6	220	123	8
- BRI	-	1	1	18,271
Third parties				
- Crédit Agricole CIB	-	64,889	-	-
Total Euro accounts	**13**	**65,118**	**678**	**18,283**
Malaysian ringgit:				
Third parties				
- RHB Bank Berhad	11,586	39,417	20,946	868
Cash in banks-other currency accounts-Third Parties	6,063	12,910	4,921	7,310
Total cash in banks	**5,404,623**	**5,045,496**	**2,770,229**	**3,011,880**

6. CASH AND CASH EQUIVALENTS (continued)

The details of cash and cash equivalents based on currency and by individual bank are as follows (continued):

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Time deposits with original maturities of three months or less				
US dollar accounts:				
Government-related entities				
- BRI	768,238	508,397	1,003,976	221,095
- BNI	407,966	193,671	398,530	168,163
- Bank Mandiri	129,284	32,760	22,958	417,300
- BTN	32,000	127,500	17,500	-
- PT Bank Syariah Mandiri ("Bank Syariah Mandiri")	275	50,005	5	5
Third parties				
- Citibank	42,500	15,000	-	-
- Industrial and Commercial Bank of China Ltd. ("ICBC")	15,000	20,000	-	-
- PT Bank Muamalat Tbk. ("Bank Muamalat")	-	12,000	-	21,550
- PT Bank Bukopin Tbk. ("Bukopin")	-	7,900	3,670	10,227
- BCA	-	-	-	10,000
- Other banks (each below US$10,000)	10,476	-	245	12,893
Total time deposits-US dollar accounts	**1,405,739**	**967,233**	**1,446,884**	**861,233**
Indonesian rupiah accounts:				
Government-related entities				
- BRI	319,912	1,351,105	999,443	1,303,358
- BTN	282,695	454,425	129,046	56,168
- Bank Mandiri	198,923	516,931	410,020	659,767
- BNI	194,097	505,346	471,616	698,688
- Bank Syariah Mandiri	72,527	137,711	48,435	38,642
- BRI Syariah	53,422	13,811	148	149
- PT Bank Rakyat Indonesia Agroniaga Tbk. ("BRI Agroniaga")	49,548	47,807	25,834	21,584
- BNI Syariah	31,879	18,591	29,340	38,070
- Other banks (each below US$10,000)	27,728	3,453	2,804	2,345
Third parties				
- ICBC	21,166	-	-	-
- Bukopin	17,202	12,098	24,648	2,108
- Bank Muamalat	4,503	7,032	4,601	10,159
- BCA	1,411	3,798	23,620	1,489
- Other banks (each below US$10,000)	3,303	17,015	14,985	9,952
Total time deposits-Indonesian rupiah accounts	**1,278,316**	**3,089,123**	**2,184,540**	**2,842,479**
Time deposits-other currencies accounts	**319**	**6,341**	**-**	**-**
Total time deposits	**2,684,374**	**4,062,697**	**3,631,424**	**3,703,712**
Total cash and cash equivalents	**8,094,779**	**9,112,312**	**6,409,827**	**6,721,568**

Annual interest rates on time deposits during nine-month period ended September 30, 2019, and for the years ended December 31, 2018, 2017, and 2016, were as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Indonesian rupiah	4.10%-8.25%	3.25%-9.00%	3.00%-8.75%	3.75%-10.50%
US dollar	0.75%-3.50%	0.50%-3.37%	0.40%-2.36%	0.50%-1.75%
Singapore dollar	0.50%	0.50%	-	-

The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of cash and cash equivalents mentioned above.

7. RESTRICTED CASH

Restricted cash are moneys in escrow accounts in US dollar and Indonesian rupiah, and are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
US dollar accounts:				
Government-related entities				
- BNI	111,483	10,401	38,526	29,965
- Bank Mandiri	28,804	58,140	2,165	3,819
- BRI	26,046	11,725	40,469	69,784
Third parties				
- The Hongkong and Shanghai Banking Corporation Limited ("HSBC")	43,985	-	-	-
- PT Bank BNP Paribas Indonesia ("BNP Paribas")	18,000	18,000	18,000	-
- SMBC Indonesia	4,552	4,000	11,752	-
- Other banks (each below US$10,000)	652	685	231	413
Indonesian rupiah accounts:				
Government-related entities				
- BNI	3,155	3,553	3,453	4,243
- BRI	1,140	1,421	3,408	6,066
- Bank Mandiri	1,644	990	875	978
Third parties				
- Other banks (each below US$10,000)	-	-	792	7,429
	239,461	**108,915**	**119,671**	**122,697**

Annual interest rates on restricted cash during during nine-month period ended September 30, 2019, and for the years ended December 31, 2018, 2017, and 2016 were as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Indonesian rupiah	4.25%-7.65%	5.00%-7.80%	2.00%-8.50%	0.75%-5.60%
US dollar	0.50%-3.25%	0.24%-0.88%	0.75%-0.80%	0.10%-0.80%

US dollar accounts

The escrow accounts were related to letters of credit ("L/C") issued for the procurement of crude oil and other petroleum products as well as bank guarantees.

Indonesian rupiah accounts

The escrow accounts are time deposits used as collateral for bank guarantees and performance bonds.

8. RECEIVABLES - THIRD PARTIES

a. Trade receivables

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables	2,241,700	2,161,456	1,792,133	1,646,792
Provision for impairment	(210,076)	(228,001)	(211,506)	(204,340)
Total	**2,031,624**	**1,933,455**	**1,580,627**	**1,442,452**

Movements in the provision for impairment of trade receivables are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(228,001)	(211,506)	(204,340)	(189,221)
Impairment during the period/year	(8,373)	(29,957)	(42,001)	(16,762)
Reversal of impairment on the recovered receivables during the period/year	17,363	7,652	33,935	2,987
Foreign exchange difference	8,935	5,810	900	(1,344)
Ending balance	**(210,076)**	**(228,001)**	**(211,506)**	**(204,340)**

The maximum exposure to credit risk at reporting date is the carrying value of the receivables mentioned above. The Group does not hold any collateral as security.

Based on management's review of the collectability of each balance of trade receivables as at the dates of September 30, 2019, and December 31, 2018, 2017, and 2016, management believes that the provision for impairment is adequate to cover the potential losse as a result of uncollected third party trade receivables.

Certain trade receivables were pledged as collateral for certain subsidiaries' long term loans (Note 20a).

Management believes that there are no significant concentrations on credit risk involving trade receivables from third parties.

Details of trade receivables by curencies are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Indonesian rupiah	1,188,380	837,130	754,907	549,361
US dollar	1,052,142	1,323,528	1,037,216	1,097,431
Singapore dollar	692	700	-	-
Thailand bath	393	-	-	-
Euro	93	98	10	-
Total	**2,241,700**	**2,161,456**	**1,792,133**	**1,646,792**

b. Other receivables

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Reinsurance assets	587,356	333,119	243,068	245,188
Receivables from subsidiary operations in oil and gas related activities	134,782	132,545	256,883	134,990
Others	293,230	286,788	139,060	281,255
Sub-total	1,015,368	752,452	639,011	661,433
Provision for impairment	(18,257)	(18,140)	(18,551)	(11,635)
Total other receivables	**997,111**	**734,312**	**620,460**	**649,798**

8. RECEIVABLES - THIRD PARTIES (continued)

b. Other receivables (continued)

Reinsurance assets represent the amount of premium paid or part of ATPI premium for prospective reinsurance and retrocession transactions.

Movements in the provision for impairment of other receivables are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(18,140)	(18,551)	(11,635)	(9,010)
Recovery (additions) of impairment during the period/year	(117)	411	(6,916)	(2,625)
Ending balance	**(18,257)**	**(18,140)**	**(18,551)**	**(11,635)**

Based on a review of the balance of other receivables at the end of the year, management believes that the allowance for impairment losses is adequate to cover possible losses that may arise from uncollectible other receivables.

9. DUE FROM THE GOVERNMENT

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
The Company:				
Receivables on revenue recognition from Disparity of Selling Price	3,160,867	2,924,148	-	-
Receivables from reimbursement of subsidy costs for LPG 3 kg cylinders	870,151	1,147,538	1,404,911	1,068,920
Receivables from reimbursement of subsidy costs for certain fuel (BBM) products	781,349	175,556	473,928	422,398
Receivables for kerosene subsidies reimbursement	17,192	16,828	-	-
Receivables from marketing fees	90,024	72,489	49,902	86,811
Kerosene conversion	10,820	10,626	-	-
Others	-	-	102	14
Sub-total	4,930,403	4,347,185	1,928,843	1,578,143
Subsidiaries	350,026	411,224	337,832	214,314
	5,280,429	4,758,409	2,266,675	1,792,457
Provision for impairment	-	-	(110,936)	-
Total (Note 41)	**5,280,429**	**4,758,409**	**2,155,739**	**1,792,457**
Current portion	(2,119,197)	(1,834,261)	(1,492,625)	(1,792,457)
Non-current portion	**3,161,232**	**2,924,148**	**663,114**	**-**

Movements in the provision for impairment of due from the Government are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	-	(110,936)	-	(33,196)
Impairment during the period/year	-	-	(363,830)	-
Reversal of impairment during the period/year	-	106,085	252,894	7,312
Adjustment	-	-	-	25,884
Foreign exchange gain	-	4,851	-	-
Ending balance	**-**	**-**	**(110,936)**	**-**

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price

Details of receivable from revenue recognition from Disparity of Selling Price are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Receivables on revenue recognition from Disparity of Selling Price:				
2018	2,657,132	2,657,132	-	-
2017	1,248,347	1,248,347	-	-
Sub-total	**3,905,479**	**3,905,479**	**-**	**-**
Initial fair value adjustments of receivables:				
2018	(773,562)	(773,562)	-	-
2017	(207,769)	(207,769)	-	-
Sub-total	**(981,331)**	**(981,331)**	**-**	**-**
Net receivables amount post fair value adjustment before unwinding interest, changes in estimate and effect of foreign exchange difference (beginning balance):				
2018	1,883,570	1,883,570	-	-
2017	1,040,578	1,040,578	-	-
Sub-total	**2,924,148**	**2,924,148**	**-**	**-**
Effects of unwinding interest:				
2018	113,761	-	-	-
2017	59,634	-	-	-
Sub-total	**173,395**	**-**	**-**	**-**
Effect of foreign exchange difference in 2019:				
2018	40,790	-	-	-
2017	22,534	-	-	-
Sub-total	**63,324**	**-**	**-**	**-**
Net ending balance:				
2018	2,038,121	1,883,570	-	-
2017	1,122,746	1,040,578	-	-
Total	**3,160,867**	**2,924,148**	**-**	**-**

On July 16, 2018, BPK issued its audit results ("LHP") No. 36/AUDITAMA VII/PDTT/07/2018 on the calculation and distribution of subsidized JBT Diesel Fuel and 3 kg LPG cylinders. Based on such LHP, the Company is recommended to request reimbursement from the Government for the 2017 Disparity of Selling Price of JBT Diesel Fuel amounting to Rp20.79 trillion or equivalent to US$1,444,076 (including VAT and Motor Vehicle Fuel Tax - "PBBKB" amounting to Rp2.71 trillion or equivalent to US$188,358) and JBKP Premium amounting to Rp5.51 trillion or equivalent to $382,904 (including VAT and PBBKB amounting to Rp0.72 trillion or equivalent to US$49,944).

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price (continued)

Based on the MoF Letter No. 642/MK.02/2018 dated August 24, 2018, the MoF based in coordination with the Minister of ESDM and the Minister of BUMN issued a policy that the Government would compensate for the Company's revenue shortfall from the sale of JBT Solar in accordance with LHP BPK. The Company recorded net receivables from the revenue shortfall from the sale of JBT Solar in 2017 amounting to Rp18.08 trillion (after deducting VAT and PBBKB of Rp2.71 trillion (equivalent to US$1,248,347) and after deducting adjustments to the fair value of receivables).

In accordance with the MoF Letter No. 642/MK.02/2018 dated August 24, 2018, the MoF, after coordinating with the MoEMR and the MoSOE, issued a policy that the Government would reimburse the Company's revenue shortfall from the sale of JBT Diesel Fuel in accordance with BPK's LHP.

On May 20, 2019, the BPK issued its LHP with Specific Purposes on the Sales and Distribution of Fuel Oil and 3kg LPG Cylinders, and Calculation of JBT Diesel Fuel & 3kg LPG Cylinders Subsidized in 2018 to PT Pertamina (Persero), PT AKR Corporindo Tbk., and other related agencies in North Sumatera, Riau, South Sumatera, Lampung, Banten, DKI Jakarta, West Java, Central Java, Yogyakarta Special Region, East Java, West Nusa Tenggara, West Kalimantan, East Kalimantan, North Sulawesi, South Sulawesi, North Maluku, and Papua No. 31/AUDITAMA VII/PDTT/05/2019, which was received by the Company on May 23, 2019. Based on such LHP, among others, the Company experienced:

- Shortfall of revenue from Disparity of Selling Price in the distribution of JBT Diesel Fuel in 2018 amounting to Rp29.31 trillion or equivalent to $2,024,203 (including VAT and PBBKB amounting to Rp18 trillion or equivalent to US$288,943);
- Shortfall of revenue from Disparity of Selling Price in the distribution of JBT Kerosene in 2018 amounting to Rp243.68 billion or equivalent to US$16,828 (excluding VAT) due to the determination of Market Index Prices ("HIP") and Basic Prices of Kerosene JBT not in accordance with the calculation of formula retail retail prices of fuel oil;
- Shortfall of revenue from Disparity of Selling Price in the distribution of JBKP Premium in 2018 amounting to Rp23.27 trillion or equivalent to $1,456,076 (including VAT and PBBKB), which consists of shortfall of revenue in the distribution of JBKP Premium in Java, Madura, and Bali ("Jamali") and outside Java, Madura, and Bali ("Non Jamali") areas amounting to Rp7.74 trillion or equivalent to US$534,205 (including VAT and PBBKB) and Rp15.53 trillion or equivalent to US$921,871 (including VAT and PBBKB), respectively;
- Excess of revenue from the sale of JBKP Premium Jamali that exceeded the Government stipulated HJE amounting to Rp234.82 billion or equivalent to US$16,216 due to the determination of the Jamali area to be the assignment area;

Based on such LHP, the Company was recommended by BPK to coordinate with the MoF, the MoEMR and the MoSOE in respect to the policy of regulating shortfall of revenue in the distribution of JBT Diesel Fuel, JBT Kerosene and JBKP Premium in 2018, in accordance with applicable procedures and regulations. Meanwhile, for the Company's excess of revenue from sale of the JBKP Premium Jamali, the Company was recommended by the BPK to deposit such excess of revenue with the State Treasury.

In accordance with the MoF Letter No. S-430/MK.02/2019 dated May 28, 2019, the MoF, after coordinating with the MoEMR and the MoSOE, issued a policy that the Government will reimburse the Company's revenue shortfall from the sale of JBT Diesel Fuel and JBKP Premium Non-Jamali in accordance with BPK's LHP No. 31/AUDITAMA VII/PDTT/05/2019. Meanwhile, the excess and shortfall of the Company's revenue from the sale of JBKP Premium Jamali become the excess and shortfall of Company's revenue.

Prior to receiving BPK's LHP and the MoF letter discussed above, the Company received BPK Letter No. 126/S/XX/05/2019 on Submission of Draft Audit Reports with Specific Purposes on the Sales and Distribution of Fuel Oil and 3kg LPG Cylinders, and Calculation of JBT Diesel Oil & 3kg LPG Cylinders Subsidized in 2018 to PT Pertamina (Persero), PT AKR Corporindo Tbk., and other related agencies dated May 17, 2019 and MoSOE Letter No. SR-330/MBU/05/2019 dated May 17, 2019 regarding the bookkeeping of the disparity in retail selling price of JBT and JBKP Non Jamali and the shortfall in of revenue from JBT Kerosene with the value in accordance with the draft of the BPK audit report.

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price (continued)

Based on the above matters, the Company recognized revenue and due from Government for the 2018 Disparity of Selling Price of JBT Diesel Fuel and JBKP Premium Non-Jamali, prior to fair value adjustment, amounting to Rp25.13 trillion or equivalent to US$1,735,260 (excluding VAT and PBBKB amounting to Rp4.18 trillion or equivalent to US$288,943) and Rp13.35 trillion or equivalent to US$921,871 (excluding VAT and PBBKB amounting to Rp2.19 trillion or equivalent to US$151,057), respectively and the 2017 Disparity of Selling Price of JBT Diesel Fuel, prior to fair value adjustment, amounting to Rp18.08 trillion or equivalent to US$1,248,347 (excluding VAT and PBBKB of Rp2.71 trillion or equivalent to US$187,252).

The assumptions used for calculating the fair value of receivable on revenue recognation from Disparity of Selling Price are as follows:

Year	Payment Installments	Discount interest rate (yield) Government Rupiah Bonds	Estimate Year of Receipt
2018	Installment 1	7.91%	2022
	Installment 2	8.01%	2023
2017	Installment 1	7.38%	2020
	Installment 2	7.72%	2021

Based on management's calculation, there are potential reimbursement of revenues from the Disparity of Selling Price of JBT Diesel Fuel and JBKP Premium Non Jamali of Rp10.77 trillion (equivalent to US$759,689) and Rp5.71 trillion (equivalent to US$402,929) (excluding VAT and PBBKB), respectively, for the nine-month period ended September 30, 2019. Revenue from the reimbursement Disparity of Selling Price will be recognized after BPK audit results of the Disparity of Selling Price and the Decision Letter from the Minister of Finance to reimburse the Disparity of Selling Price ("Decision Letter") have been received by the Company (Notes 2r and 3.a.iv). As of the date of the completion of these consolidated financial statements, BPK is in the process of auditing the 2019 Disparity of Selling Price of the Company based on Assignment Letter No. 91/ST/IX-XX.1/11/2019 dated November 29, 2019.

b. Receivable from reimbursement of subsidy costs for LPG 3 kg cylinders

These receivables represent subsidy reimbursements for 3 kg LPG cylinders which were distributed to the public by the Company. This Government assignment is in the form of a PSO and its pricing is based on a yearly contract with MoEMR.

The receivable balance for the 3 kg LPG cylinders subsidy will be settled through the APBN mechanism in the next period.

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	1,147,538	1,404,911	1,068,920	934,825
Subsidy reimbursements for 3 kg LPG cylinders for current year (Note 29)	1,991,199	3,496,603	2,977,967	1,817,647
Correction from government audit for subsidy reimbursement for 3 kg LPG cylinders for the year:				
- 2018 (Note 29)	-	(1,252)	-	-
- 2017 (Note 29)	-	(5,661)	-	-
- 2016 (Note 29)	-	-	(484)	-
- 2015 (Note 29)	-	-	-	(479)
Cash received	(2,333,953)	(3,614,277)	(2,624,110)	(1,720,295)
Foreign exchange gain (loss)	65,367	(132,786)	(17,382)	37,222
Ending balance	**870,151**	**1,147,538**	**1,404,911**	**1,068,920**

9. DUE FROM THE GOVERNMENT (continued)

c. Receivables from reimbursement of subsidy costs for certain fuel (BBM) products

The Company's receivable of subsidy reimbursements for BBM products represents billings for the BBM subsidy provided to the public.

The PSO mandate to the Company from the Government is based on annual contract with BPH Migas. The retail sales price of the subsidised BBM products is based on MoEMR's Decree.

The receivable balance of subsidy reimbursements for BBM products will be setlled through the next State Budget and Expenditure ("APBN") period.

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	175,556	473,928	422,398	893,062
Subsidy reimbursements for BBM products for current year (Note 29)	1,663,358	2,126,796	595,206	753,250
Taxes	112,678	266,693	69,617	83,145
Correction from Government audit for subsidy reimbursement for BBM products for the year:				
- 2018 (Note 29)	-	(699)	-	-
- 2017 (Note 29)	-	(147)	-	-
- 2016 (Note 29)	-	-	(605)	-
- 2015 (Note 29)	-	-	-	(1,574)
Cash received	(1,178,323)	(2,600,487)	(600,992)	(1,334,981)
Gain(loss) on foreign exchange	8,080	(90,528)	(11,696)	29,496
Ending balance	**781,349**	**175,556**	**473,928**	**422,398**

Corrections of the calculation of the fuel subsidy cost reimbursement bill is based on the results of the BPK's and recorded in the period in which the audit was completed.

On August 16, 2018, the MoEMR issued Regulation No. 40 of 2018 which replaces MoEMR Regulation No. 39 of 2014 regarding the calculation of the retail selling price of fuel oil. In accordance with the new regulation, the retail selling price of Automotive Diesel Oil ("ADO") per liter at the point of delivery is calculated based on formula prices, including VAT, with a maximum subsidy of Rp2,000 (full amount) per liter, applied retrospectively starting January 1, 2018.

d. Receivables for kerosene subsidies reimbursement

As discussed in Note 9a above, based on BPK's LHP No. 31/AUDITAMA VII/PDTT/05/2019 dated May 20, 2019, the Company experienced a shortfall of revenue in the distribution of JBT Kerosene in 2018 amounting to Rp243.68 billion (excluding VAT amounting to Rp24.38 billion) due to the determination of Market Index Prices ("HIP") and Basic Prices of Kerosene JBT were not in accordance with the calculation of formula retail prices of fuel oil stipulated in MoEMR Decree No.62K/10/MEM/2019 regarding Basic Formula Price for Specific Type of Fuel Oils and Special Types of Fuel Assignment. The Company's management believes that such shortfall of revenue will be reimbursed by the Government through a subsidy mechanism.

9. DUE FROM THE GOVERNMENT (continued)

e. Receivables from marketing fees

These receivables represent amounts due from the Government through SKK Migas to the Company for fees from marketing activities in relation to the Government's crude oil, natural gas and LNG.

The details of marketing fees are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Receivables of marketing fees:				
2019	17,535	-	-	-
2018	22,587	22,587	-	-
2017	26,529	26,529	26,529	-
2016	23,373	23,373	23,373	23,373
2015	-	-	-	20,698
2014	-	-	-	9,150
2013	-	-	-	9,007
2012	-	-	-	11,866
2011	-	-	-	12,717
Total	**90,024**	**72,489**	**49,902**	**86,811**

f. Subsidiaries receivables

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
PEP				
- Domestic Market Obligation ("DMO") fees	91,190	106,398	90,930	77,340
- Underlifting	10,354	18,942	-	-
PHE				
- DMO fees	20,089	15,414	25,859	25,613
- Underlifting	17,420	25,730	46,480	31,395
PEPC				
- Underlifiting	188,117	224,904	174,563	79,966
PHI				
- DMO fees	20,885	18,780	-	-
- Underlifting	1,971	1,056	-	-
Total - subsidiaries	**350,026**	**411,224**	**337,832**	**214,314**

DMO fees represent amounts due from the Government in relation with the obligations of subsidiaries in providing crude oil to meet domestic market needs for oil products in accordance with their KKS.

The underlifting receivables represent receivables from subsidiaries of SKK Migas as a result of SKK Migas, actual lifting of crude oil and gas being higher than its entitlement for the respective year.

Based on management's review of the collectibility of each balance of subsidiaries receivables, management believes that the provision for impairment is adequate to cover potential losses as a result of uncollected subsidiaries' receivables from Government.

10. INVENTORIES

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Gas	3,566	13,984	23,528	6,711
Crude oil:				
Domestic production	953,996	1,026,225	1,029,639	799,513
Imported	358,530	579,765	754,663	467,391
Sub-total for crude oil	1,312,526	1,605,990	1,784,302	1,266,904
Oil products:				
Automotive Diesel Oil ("ADO")	761,814	1,018,791	755,620	593,658
Premium gasoline	575,526	536,309	594,740	461,811
Pertamax, Pertamax Plus, Pertalite gasoline and Pertadex (diesel oil)	410,559	491,005	451,999	311,575
Intermediary	371,793	337,246	272,786	254,826
Oil products in process of production	359,698	399,963	347,408	327,709
Avtur and Avigas	200,149	264,545	220,903	125,795
Petrochemicals	198,115	170,815	127,457	116,969
LPG	137,115	262,104	277,690	207,856
Kerosene	80,679	94,299	75,503	73,808
Industrial/ Marine Fuel Oil ("IFO/MFO")	78,531	148,621	118,515	97,658
Industrial Diesel Oil ("IDO")	13,384	17,563	21,722	27,315
Others	387,774	476,999	514,176	391,537
Sub-total for oil products	3,575,137	4,218,260	3,778,519	2,990,517
Sub-total for gas, crude oil and oil products	4,891,229	5,838,234	5,586,349	4,264,132
Less:				
Provision for decline in value of oil products (Note 32)	(158,809)	(167,270)	(92,854)	(76,542)
	4,732,420	5,670,964	5,493,495	4,187,590
Materials	895,556	754,228	645,825	637,655
Less:				
Provision for decline in value of materials	(108,863)	(102,027)	(103,183)	(30,223)
	786,693	652,201	542,642	607,432
Total	**5,519,113**	**6,323,165**	**6,036,137**	**4,795,022**

Movements in the provision for decline in value of oil products are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(167,270)	(92,854)	(76,542)	(225,457)
Reversal (addition) during the period/year - net (Note 32)	8,461	(74,416)	(16,312)	148,915
Ending balance	**(158,809)**	**(167,270)**	**(92,854)**	**(76,542)**

Movements in the provision for decline in value of materials are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(102,027)	(103,183)	(30,223)	(29,459)
(Addition) reversal during the period/year - net	(6,836)	1,156	(72,960)	(764)
Ending balance	(108,863)	(102,027)	(103,183)	(30,223)

10. INVENTORIES (continued)

Management believes that the provision for decline in value of oil products and materials are adequate to cover possible losses that may arise from a decline in the realizable value of inventories.

As of September 30, 2019 inventories were insured against fire and other risks (Note 13). Management believes that the insurance coverage amount is adequate to cover any possible losses that may arise in relation to the insured inventories.

11. OTHER INVESTMENTS

These investments represent net assets held for distribution to the Company in connection with the liquidation of Pertamina Energy Trading Limited ("Petral"), Zambesi Investment Limited ("Zambesi") and Pertamina Energy Services Pte.Ltd. ("PES") in accordance with the General Meeting of Shareholder ("GMS") decision of the Company on July 13, 2015.

On March 13, 2017, Petral has distributed its funds to the Company. On June 16, 2017, Zambesi was liquidated. On October 31, 2017, Petral was liquidated.

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the balance of net assets held for distribution to the Company based on the liquidator's report for PES amounted to US$74,126, US$80,171, US$27,328, and US$43,190, respectively.

Based on the Company's GMS dated January 3, 2019, the Company's shareholder agreed to extend the liquidation period of PES until the completion of the dissolution/liquidation process, and approved the Company to take the corporate actions needed to complete the dissolution/liquidation.

12. LONG-TERM INVESTMENTS

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Investment in oil and gas blocks - net	927,388	1,024,237	1,227,187	1,427,011
Investments in associates - net	723,884	725,846	583,694	697,850
Investment in bonds - net	391,307	391,307	391,307	391,307
Investments in joint ventures	312,971	369,922	457,405	480,756
Investment properties	292,602	280,668	284,354	304,373
Investments in shares of stock - net	6,292	6,292	6,292	6,292
Other financial assets	18,985	20,782	20,679	21,850
Total	**2,673,429**	**2,819,054**	**2,970,918**	**3,329,439**

a. Investment in oil and gas block

Investment in oil and gas blocks represents the Group's investment in several oil and gas blocks located in Malaysia which are being operated by PTT Exploration and Production ("PTTEP") (previously by Murphy Sabah Oil Co. Ltd. and Murphy Sarawak Oil Co. Ltd.). The Group recorded the investment using the equity method because it has significant influence in the undivided interest of those oil and gas blocks.

The movement of investments in oil and gas block are as follows:

	September 30, 2019 (unaudited)					
	Beginning balance	Addition	Adjustment	Transfer	Recovery/ (impairment) in value	Ending balance
Cost	1,556,487	-	24,427	-	(52,404)	1,528,510
Accumulated amortization	(532,250)	(68,872)	-	-	-	(601,122)
Net book value	**1,024,237**	**(68,872)**	**24,427**	**-**	**(52,404)**	**927,388**

12. LONG-TERM INVESTMENTS (continued)

a. Investment in oil and gas block (continued)

The movement of investments in oil and gas block are as follows (continued):

	December 31, 2018					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,614,965	-	96,295	-	(154,773)	1,556,487
Accumulated amortization	(387,778)	(144,472)	-	-	-	(532,250)
Net book value	**1,227,187**	**(144,472)**	**96,295**	**-**	**(154,773)**	**1,024,237**

	December 31, 2017					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,698,348	-	(113)	-	(83,270)	1,614,965
Accumulated amortization	(271,337)	(116,441)	-	-	-	(387,778)
Net book value	**1,427,011**	**(116,441)**	**(113)**	**-**	**(83,270)**	**1,227,187**

	December 31, 2016					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,632,706	12,269	(60,917)	-	114,290	1,698,348
Accumulated amortization	(156,861)	(114,476)	-	-	-	(271,337)
Net book value	**1,475,845**	**(102,207)**	**(60,917)**	**-**	**114,290**	**1,427,011**

b. Investments in associates

The movement of investments in associates are as follows:

	September 30, 2019 (unaudited)							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- PPT Energy Trading Co., Ltd.	50.00%	48,038	-	-	2,425	-	-	50,463
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	82,005	-	361	(40,353)	-	-	42,013
		130,043	-	361	(37,928)	-	-	92,476
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	279,219	-	5	14,080	-	-	293,304
- PT Asuransi Samsung Tugu	19.50%	9,069	-	77	605	(65)	-	9,686
- Seplat Petroleum Development Company Plc, Nigeria	20.46%	224,548	-	-	41,168	(5,971)	-	259,745
- PT Gas Energi Jambi [c)]	40.00%	-	-	-	-	-	-	-
- Others	19.67%-50%	82,967	(16,422)	7,729	(1,153)	(4,448)	-	68,673
		595,803	(16,422)	7,811	54,700	(10,484)	-	631,408
Total investments in associates		**725,846**	**(16,422)**	**8,172**	**16,772**	**(10,484)**	**-**	**723,884**

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

The movement of investments in associates are as follows (continued):

	December 31, 2018							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- PPT Enegy Trading Co., Ltd.	50.00%	35,489	-	-	12,549	-	-	48,038
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	151,937	-	-	(69,932)	-	-	82,005
		187,426	-	-	(57,383)	-	-	130,043
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	240,437	-	2	38,780	-	-	279,219
- PT Asuransi Samsung Tugu	19.50%	8,741	-	19	434	(125)	-	9,069
- Seplat Petroleum Development Company Plc, Nigeria	20.46%	92,440	-	68,043	76,124	(12,059)	-	224,548
- PT Gas Energi Jambi [c]	40.00%	-	-	-	-	-	-	-
- Others	19.67%-50%	54,650	27,458	2,298	(1,439)	-	-	82,967
		396,268	27,458	70,362	113,899	(12,184)	-	595,803
Total investments in associates		**583,694**	**27,458**	**70,362**	**56,516**	**(12,184)**	**-**	**725,846**

	December 31, 2017							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- PPT Energy Trading Co., Ltd.	50.00%	32,499	-	1,516	2,616	(1,142)	-	35,489
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	204,907	-	-	(52,970)	-	-	151,937
		237,406	-	1,516	(50,354)	(1,142)	-	187,426
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	195,083	-	-	45,354	-	-	240,437
- PT Tugu Reasuransi Indonesia [a]	33.01%	29,849	-	(29,849)	-	-	-	-
- PT Asuransi Samsung Tugu	19.50%	8,290	-	(19)	648	(178)	-	8,741
- Etablissements Maurel et Prom SA [b] (Notes 4c)	72.65%	227,222	-	(227,222)	-	-	-	-
- Seplat Petroleum Development Company Plc, Nigeria	21.37%	-	92,440	-	-	-	-	92,440
- PT Gas Energi Jambi [c]	40.00%	-	-	-	-	-	-	-
- Others	19.67%-50%	-	54,650	-	-	-	-	54,650
		460,444	147,090	(257,090)	46,002	(178)	-	396,268
Total investments in associates		**697,850**	**147,090**	**(255,574)**	**(4,352)**	**(1,320)**	**-**	**583,694**

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

The movement of investments in associates are as follows (continued):

	December 31, 2016							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- PPT Energy Trading Co., Ltd.	50.00%	29,179	-	2,720	1,966	(1,366)	-	32,499
- Korea Indonesia Petroleum Co. Ltd. Labuan [d]	45.00%	1,178	(434)	(642)	(102)	-	-	-
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	259,416	-	-	(54,509)	-	-	204,907
		289,773	(434)	2,078	(52,645)	(1,366)	-	237,406
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	176,831	-	-	18,252	-	-	195,083
- PT Tugu Reasuransi Indonesia	24.47%	24,411	-	2,167	5,444	(2,173)	-	29,849
- PT Asuransi Samsung Tugu	19.50%	7,697	-	(85)	893	(215)	-	8,290
- Etablissements Maurel et Prom SA [b] (Notes 4c)	24.53%	-	227,222	-	-	-	-	227,222
- PT Gas Energi Jambi [c]	40.00%	-	-	-	-	-	-	-
		208,939	227,222	2,082	24,589	(2,388)	-	460,444
Total investments in associates		**498,712**	**226,788**	**4,160**	**(28,056)**	**(3,754)**	**-**	**697,850**

[a] In 2017, the Group obtained control over PT Tugu Reasuransi Indonesia ("TRI") and consolidates its financial statements.
[b] On February 15, 2017, PT Pertamina Internasional Eksplorasi & Produksi had a 72.65% ownership interest in Etablissements Maurel et Prom SA and consolidates its financial instrument.
[c] PGN has ownership interest in PT Gas Energi Jambi ("GEJ") of 40.00% from 2015, GEJ is in an accumulative losses position.
[d] In 2016, the Company sold its shares in Korea Indonesia Petroleum Co. Ltd., Labuan.

Management believes that the provision for decline in value of investments in associates is adequate to cover possible losses that may arise from declining in value.

The Group's share of the results of its principal associates and their aggregated assets (including goodwill) and liabilities, are as follows:

	Country of Incorporation	Assets	Liabilities	Revenues	Profit (loss)	Percentage of ownership
September 30, 2019 (unaudited)						
- PPT Energy Trading Co., Ltd.	Japan	158,389	(71,532)	265,738	4,850	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	830,049	(743,586)	60,340	(83,050)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,637,090	(1,624,730)	864,214	48,211	29.00%
- PT Asuransi Samsung Tugu	Indonesia	67,699	(35,411)	6,386	2,017	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,541,491	(775,192)	494,880	184,598	20.46%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%
December 31, 2018						
- PPT Energy Trading Co., Ltd.	Japan	118,983	(30,486)	731,189	25,098	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	866,155	(697,385)	65,136	(141,991)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,646,556	(1,669,778)	1,174,024	133,726	29.00%
- PT Asuransi Samsung Tugu	Indonesia	61,997	(31,766)	9,046	1,446	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,526,565	(925,680)	746,140	146,576	20.46%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

	Country of Incorporation	Assets	Liabilities	Revenues	Profit (loss)	Percentage of ownership
December 31, 2017						
- PPT Energy Trading Co., Ltd.	Japan	153,471	(82,496)	692,966	5,232	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	601,445	(1,045,454)	59,574	(50,519)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,466,693	(1,627,338)	998,208	155,704	29.00%
- PT Asuransi Samsung Tugu	Indonesia	55,775	(36,791)	11,161	2,163	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,207,964	(975,232)	371,413	(3,307)	21.37%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%
December 31, 2016						
- PPT Energy Trading Co., Ltd.	Japan	135,085	(70,089)	524,180	3,932	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	604,629	(996,212)	42,935	(53,421)	48.59%
- Korea Indonesia Petroleum Co. Ltd., Labuan	Malaysia	2,447	(62)	-	(228)	45.00%
- PT Donggi Senoro LNG	Indonesia	2,454,345	(1,774,286)	755,295	73,038	29.00%
- PT Tugu Reasuransi Indonesia	Indonesia	202,633	(124,060)	107,491	14,456	24.47%
- PT Asuransi Samsung Tugu	Indonesia	62,071	(34,436)	10,798	2,977	19.50%
- Etablissements Maurel et Prom SA [a] (Notes 4c)	France	2,443,992	(1,348,198)	149,588	(38,565)	24.53%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%

c. Investment in bonds

As of September 30, 2019 and December 31, 2018, 2017, and 2016, investment in bonds represents investment in bonds issued by PT Trans-Pacific Petrochemical Indotama.

d. Investment in joint ventures

The movements of investments in joint ventures are as follows:

	September 30, 2019 (unaudited)							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	89,976	-	-	12,447	(23,100)	-	79,323
- PT Patra SK	35.00%	62,406	-	(210)	4,317	(10,500)	-	56,013
- PT Indo Thai Trading (Note 1b)	51.00%	7,070	-	(7,070)	-	-	-	-
- PT Perta Daya Gas	65.00%	3,734	-	-	3,081	-	-	6,815
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	407	-	-	-	-	-	407
- PT Transportasi Gas Indonesia	59.87%	202,743	-	-	21,421	(59,019)	-	165,145
- PT Permata Karya Jasa	60.00%	3,586	-	-	1,682	-	-	5,268
Total investments in joint venture		**369,922**	**-**	**(7,280)**	**42,948**	**(92,619)**	**-**	**312,971**

12. LONG-TERM INVESTMENTS (continued)

d. Investment in joint ventures (continued)

The movements of investments in joint ventures are as follows (continued):

	December 31, 2018							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	91,173	-	32	21,871	(23,100)	-	89,976
- PT Patra SK	35.00%	65,769	-	-	5,387	(8,750)	-	62,406
- PT Indo Thai Trading	51.00%	6,281	790	(791)	790	-	-	7,070
- PT Perta Daya Gas	65.00%	1,683	-	28	2,023	-	-	3,734
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	407	-	-	-	-	-	407
- PT Transportasi Gas Indonesia	59.87%	281,700	-	(1,013)	27,814	(105,758)	-	202,743
- Unimar L.L.C *)	50.00%	10,392	(7,176)	(1,657)	6,941	(8,500)	-	-
- PT Permata Karya Jasa	60.00%	-	2,416	-	1,382	(212)	-	3,586
Total investments in joint ventures		**457,405**	**(3,970)**	**(3,401)**	**66,208**	**(146,320)**	**-**	**369,922**

*) Unimar L.L.C 11.25% participating interest in old Sanga-sanga PSC which expired on August 8, 2018.

	December 31, 2017							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	79,383	-	7,355	17,635	(13,200)	-	91,173
- PT Patra SK	35.00%	68,919	-	(26)	3,876	(7,000)	-	65,769
- PT Indo Thai Trading	51.00%	4,815	-	(2)	1,468	-	-	6,281
- PT Perta Daya Gas	65.00%	1,403	-	(111)	391	-	-	1,683
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	-	407	-	-	-	-	407
- PT Elnusa CGGVeritas Seismic *)	20.96%	-	-	-	-	-	-	-
- PT Transportasi Gas Indonesia	59.87%	281,167	-	-	26,072	(25,539)	-	281,700
- Unimar L.L.C	50.00%	45,069	-	-	(7,177)	(27,500)	-	10,392
Total investments in joint ventures		**480,756**	**407**	**7,216**	**42,265**	**(73,239)**	**-**	**457,405**

**) On May 24, 2017, PT Elnusa CGGVeritas Seismic was dissolved

	December 31, 2016							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Patra SK	35.00%	64,538	-	(13)	4,394	-	-	68,919
- PT Indo Thai Trading	51.00%	3,711	-	-	1,104	-	-	4,815
- PT Perta Samtan Gas	66.00%	77,368	-	-	5,513	(3,498)	-	79,383
- PT Perta Daya Gas	65.00%	1,301	-	-	102	-	-	1,403
- PT Elnusa CGGVeritas Seismic	20.96%	-	-	-		-	-	-
- PT Transportasi Gas Indonesia	59.87%	278,516	-		26,357	(23,706)	-	281,167
- Unimar L.L.C	50.00%	-	53,724	11,074	(1,729)	(18,000)	-	45,069
Total investments in joint ventures		**425,434**	**53,724**	**11,061**	**35,741**	**(45,204)**	**-**	**480,756**

12. LONG-TERM INVESTMENTS (continued)

d. Investment in joint ventures (continued)

The Group's share of the results of its principal joint ventures and their aggregated assets (including goodwill) and liabilities are as follows:

	Country of Incorporation	Assets	Liabilities	Revenues	Profit (loss)	Percentage ownership
September 30, 2019 (unaudited)						
- PT Patra SK	Indonesia	222,215	(62,179)	239,300	11,819	35.00%
- PT Perta Samtan Gas	Indonesia	162,961	(42,774)	74,062	18,860	66.00%
- PT Perta Daya Gas	Indonesia	50,497	(40,013)	9,748	4,740	65.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	515	(3)	-	(7)	20.96%
- PT Transportasi Gas Indonesia	Indonesia	342,770	(66,931)	114,314	35,781	59.87%
- PT Permata Karya Jasa*	Indonesia	11,027	(2,247)	16,654	2,803	60.00%
- PT Pertamina Rosneft Pengolahan dan Petrokimia	Indonesia	739	-	-	-	55.00%
December 31, 2018						
- PT Patra SK	Indonesia	232,842	(54,539)	341,114	15,391	35.00%
- PT Perta Samtan Gas	Indonesia	166,010	(29,683)	121,802	33,187	66.00%
- PT Perta Daya Gas	Indonesia	48,618	(42,873)	12,497	3,113	65.00%
- PT Indo Thai Trading	Indonesia	35,332	(21,470)	184,779	1,549	51.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	511	-	-	3	20.96%
- PT Transportasi Gas Indonesia	Indonesia	735,029	(96,391)	153,413	46,458	59.87%
- Unimar L.L.C	USA	33,740	(19,387)	43,918	13,881	28.48%
- PT Permata Karya Jasa*	Indonesia	6,308	(2,040)	16,301	1,383	60.00%
- PT Pertamina Rosneft Pengolahan dan Petrokimia	Indonesia	739	-	-	-	55.00%
December 31, 2017						
- PT Patra SK	Indonesia	244,717	(59,696)	259,596	11,072	35.00%
- PT Perta Samtan Gas	Indonesia	180,172	(42,032)	106,950	26,720	66.00%
- PT Perta Daya Gas	Indonesia	53,219	(50,630)	12,469	602	65.00%
- PT Indo Thai Trading	Indonesia	31,994	(19,369)	156,716	2,869	51.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	515	-	-	-	20.96%
- PT Transportasi Gas Indonesia	Indonesia	557,875	(87,357)	151,625	43,548	59.87%
- Unimar L.L.C	USA	49,370	(31,899)	61,993	(9,991)	50.00%
- PT Pertamina Rosneft Pengolahan dan Petrokimia	Indonesia	739	-	-	-	55.00%
December 31, 2016						
- PT Patra SK	Indonesia	239,169	(42,256)	213,705	12,553	35.00%
- PT Indo Thai Trading	Indonesia	18,885	(9,445)	116,865	2,164	51.00%
- PT Perta Samtan Gas	Indonesia	179,326	(47,852)	73,617	8,353	66.00%
- PT Perta Daya Gas	Indonesia	59,460	(57,473)	12,842	157	65.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	522	-	-	-	20.96%
- PT Transportasi Gas Indonesia	Indonesia	618,630	(149,001)	158,719	44,024	59.87%
- Unimar L.L.C	USA	109,733	(27,270)	14,435	(3,458)	50.00%

* Note 1b.ii

e. Investment properties

	September 30, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	266,911	-	-	13,741	280,652
Buildings	42,102	17	-	(48)	42,071
Total historical cost	309,013	17	-	13,693	322,723
Accumulated depreciation:					
Buildings	(28,345)	(1,448)	-	(328)	(30,121)
Net book value	**280,668**				**292,602**

12. LONG-TERM INVESTMENTS (continued)

e. Investment properties (continued)

	December 31, 2018				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	269,226	1,074	(17,368)	13,979	266,911
Buildings	43,287	1,217	-	(2,402)	42,102
Total historical cost	312,513	2,291	(17,368)	11,577	309,013
Accumulated depreciation:					
Buildings	(28,159)	(2,058)	-	1,872	(28,345)
Net book value	**284,354**				**280,668**

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	288,314	-	-	(19,088)	269,226
Buildings	43,042	-	-	245	43,287
Total historical cost	331,356	-	-	(18,843)	312,513
Accumulated depreciation:					
Buildings	(26,983)	(2,301)	-	1,125	(28,159)
Net book value	**304,373**				**284,354**

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	265,358	1,018	-	21,938	288,314
Buildings	29,095	-	-	13,947	43,042
Total historical cost	294,453	1,018	-	35,885	331,356
Accumulated depreciation:					
Buildings	(19,301)	(973)	-	(6,709)	(26,983)
Net book value	**275,152**				**304,373**

Depreciation expenses for the nine-month periods ended September 30, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016 with respect to such investment properties amounted to US$1,448, US$642 US$2,058, US$2,301 and US$973, respectively (Note 37).

As of September 30, 2019, all of the Group's investment properties, except land and land rights, were insured against fire and other possible risks (Note 13).

As of September 30, 2019, and December 31, 2018, 2017, and 2016, management has estimated fair values of the investment properties to be US$1,552,307, US$1,803,218, US$1,503,088, and US$2,068,793, respectively.

Rental income from investment properties recognized for the nine-month periods ended September 30, 2019, 2018 and for the years ended December 31, 2018, 2017, and 2016 amounted to US$21,952, US$20,493, US$26,588, US$11,792, and US$29,836, respectively.

Based on the Group management's review, there were no events or changes in circumstances which indicated impairment in the value of investment properties as of September 30, 2019, and December 31, 2018, 2017, and 2016.

12. LONG-TERM INVESTMENTS (continued)

f. Investments in shares of stock

	Percentage of ownership				Balance			
	September 30, 2019 (unaudited)	December 31,			September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016		2018	2017	2016
The Company								
- PT Seamless Pipe Indonesia Jaya	4.97%	4.97%	4.97%	10.40%	25,026	25,026	25,026	25,026
- PT Arun NGL [a]	100.00%	100.00%	100.00%	85.00%	170	170	170	170
- PT Badak NGL [b]	55.00%	55.00%	55.00%	55.00%	149	149	149	149
					25,345	25,345	25,345	25,345
Subsidiaries								
- PT Staco Jasapratama Indonesia	4.46%	4.46%	4.46%	4.46%	751	751	751	751
- PT Marga Raya Jawa Tol	6.86%	6.86%	6.86%	6.86%	2,690	2,690	2,690	2,690
- PT Trans Javagas Pipeline	10.00%	10.00%	10.00%	10.00%	739	739	739	739
- PT Asuransi Maipark Indonesia	7.31%	7.31%	7.31%	7.31%	604	604	604	604
- PT Bhakti Patra Nusantara	4.11%	4.11%	4.11%	4.11%	77	77	77	77
- PT Banten Gas Synergi	0.14%	0.14%	0.14%	0.14%	3	3	3	3
					4,864	4,864	4,864	4,864
Total					**30,209**	**30,209**	**30,209**	**30,209**
Provision for impairment					(23,917)	(23,917)	(23,917)	(23,917)
Net					**6,292**	**6,292**	**6,292**	**6,292**

[a] in liquidation process
[b] refer to note 2d

The Group classified its investments in shares of stock as available-for-sale at cost because the Company, in subtance, does not control those companies. These investments are measured at cost since their fair values cannot be measured reliably.

The Group did not recognize its share on the changes in the joint ventures entities' net assets arising from other comprehensive income since the amounts are not material.

g. Other financial assets

As of September 30, 2019, and December 31, 2018, 2017, and 2016, other financial assets mainly represent investment in bonds owned by PT Asuransi Tugu Pratama Indonesia Tbk. (formerly PT Tugu Pratama Indonesia).

13. FIXED ASSETS

	September 30, 2019 (unaudited)					
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Translations	Ending balance
Acquisition cost:						
Direct acquisition:						
Land and land rights	1,705,095	12,430	-	26,473	(702)	1,743,296
Tanks, pipeline installations and other equipment	9,322,018	125,239	-	605,206	417	10,052,880
Refineries	4,265,934	257	-	164,002	21	4,430,214
Buildings	1,281,451	8,963	(216)	(1,314)	2,904	1,291,788
Ships and aircrafts	2,096,335	32,835	-	6,828	5,023	2,141,021
Moveable assets	1,633,638	18,500	(1,995)	89,594	7,544	1,747,281
Assets under construction	2,129,917	605,123	(1,094)	(934,612)	(966)	1,798,368
Sub-total	22,434,388	803,347	(3,305)	(43,823)	14,241	23,204,848
Finance lease assets:						
Land rights	-	-	-	-	-	-
Buildings	205,737	-	-	-	-	205,737
Tanks, pipelines installations and other equipment	414,634	15,110	-	(34,785)	-	394,959
Moveable assets	167,015	-	(157)	(7,825)	391	159,424
Sub-total	787,386	15,110	(157)	(42,610)	391	760,120
Total acquisition cost	**23,221,774**	**818,457**	**(3,462)**	**(86,433)**	**14,632**	**23,964,968**
Accumulated depreciation:						
Direct acquisition:						
Land rights	(212)	-	-	-	(40)	(252)
Tanks, pipeline installation and other equipment	(4,834,321)	(387,314)	-	(41,951)	3,173	(5,260,413)
Refineries	(2,598,926)	(191,618)	-	3,352	(32)	(2,787,224)
Buildings	(526,815)	(47,459)	177	4,581	(1,179)	(570,695)
Ships and aircrafts	(813,091)	(77,811)	-	2,676	(1,126)	(889,352)
Moveable assets	(986,804)	(76,163)	1,919	(2,797)	1,018	(1,062,827)
Sub-total	(9,760,169)	(780,365)	2,096	(34,139)	1,814	(10,570,763)
Finance lease assets:						
Land rights	-	-	-	-	-	-
Buildings	(161,389)	(13,943)	-	-	-	(175,332)
Tanks, pipeline installations and other equipment	(249,815)	(26,733)	-	2,323	-	(274,225)
Moveable assets	(136,838)	(1,639)	157	-	(3,454)	(141,774)
Sub-total	(548,042)	(42,315)	157	2,323	(3,454)	(591,331)
Total accumulated depreciation	**(10,308,211)**	**(822,680)**	**2,253**	**(31,816)**	**(1,640)**	**(11,162,094)**
Provision for Impairment	(54,289)	(95,937)	2,481	-	(14)	(147,759)
Net book value	**12,859,274**					**12,655,115**

13. FIXED ASSETS (continued)

	December 31, 2018					
	Beginning balance	Additions	Deduction	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost:						
Direct acquisition:						
Land and land rights	1,702,277	3,034	-	5,618	(5,834)	1,705,095
Tanks, pipeline installations and other equipment	9,168,847	28,693	(569)	131,485	(6,438)	9,322,018
Refineries	4,022,746	145,518	-	97,740	(70)	4,265,934
Buildings	1,200,885	20,252	(367)	70,994	(10,313)	1,281,451
Ships and aircrafts	2,015,720	120,523	-	(26,626)	(13,282)	2,096,335
Moveable assets	1,624,785	36,722	(5,875)	7,713	(29,707)	1,633,638
Assets under construction	1,446,340	1,083,618	-	(397,603)	(2,438)	2,129,917
Sub-total	21,181,600	1,438,360	(6,811)	(110,679)	(68,082)	22,434,388
Finance lease assets:						
Land rights	157,605	-	-	(155,364)	(2,241)	-
Buildings	83,987	-	-	121,750	-	205,737
Tanks, pipeline installations and other equipment	369,534	44,097	-	1,003	-	414,634
Moveable assets	156,432	10,707	-	-	(124)	167,015
Sub-total	767,558	54,804	-	(32,611)	(2,365)	787,386
Total acquisition cost	**21,949,158**	**1,493,164**	**(6,811)**	**(143,290)**	**(70,447)**	**23,221,774**
Accumulated depreciation:						
Direct acquisition:						
Land rights	(876)	-	-	-	664	(212)
Tanks, pipeline installations and other equipment	(4,393,822)	(504,253)	42	58,559	5,153	(4,834,321)
Refineries	(2,349,134)	(249,586)	-	(307)	101	(2,598,926)
Buildings	(477,017)	(52,430)	271	(1,435)	3,796	(526,815)
Ships and aircrafts	(775,835)	(105,264)	-	65,138	2,870	(813,091)
Moveable assets	(969,682)	(103,113)	5,697	61,156	19,138	(986,804)
Sub-total	(8,966,366)	(1,014,646)	6,010	183,111	31,722	(9,760,169)
Finance lease assets:						
Land rights	(82,872)	(6,070)	-	88,942	-	-
Buildings	(58,902)	(14,272)	-	(88,215)	-	(161,389)
Tanks, pipeline installations and other equipment	(210,786)	(38,302)	-	(727)	-	(249,815)
Moveable assets	(133,666)	(7,877)	-	4,628	77	(136,838)
Sub-total	(486,226)	(66,521)	-	4,628	77	(548,042)
Total accumulated depreciation	**(9,452,592)**	**(1,081,167)**	**6,010**	**187,739**	**31,799**	**(10,308,211)**
Provision for impairment	(57,055)	-	2,719	-	47	(54,289)
Net book value	**12,439,511**					**12,859,274**

13. FIXED ASSETS (continued)

	December 31, 2017					
	Beginning balance	Additions	Deduction	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost:						
Direct acquisition:						
Land and land rights	1,663,116	29,716	-	10,259	(814)	1,702,277
Tanks, pipeline installations and other equipment	8,226,598	156,997	(1,855)	787,473	(366)	9,168,847
Refineries	3,815,932	175,395	(349)	31,774	(6)	4,022,746
Buildings	1,003,055	16,298	(1,984)	193,110	(9,594)	1,200,885
Ships and aircrafts	1,894,266	52,838	-	70,460	(1,844)	2,015,720
Moveable assets	1,563,969	86,287	(7,203)	(29,853)	11,585	1,624,785
Assets under construction	1,792,241	999,558	(12,896)	(1,332,310)	(253)	1,446,340
Sub-total	19,959,177	1,517,089	(24,287)	(269,087)	(1,292)	21,181,600
Finance lease assets:						
Land rights	122,815	-	-	35,216	(426)	157,605
Buildings	83,987	-	-	-	-	83,987
Tanks, pipeline installations and other equipment	305,567	63,967	-	-	-	369,534
Moveable assets	152,167	6,498	-	(1,740)	(493)	156,432
Sub-total	664,536	70,465	-	33,476	(919)	767,558
Total acquisition cost	**20,623,713**	**1,587,554**	**(24,287)**	**(235,611)**	**(2,211)**	**21,949,158**
Accumulated depreciation:						
Direct acquisition:						
Land rights	(697)	-	-	(181)	2	(876)
Tanks, pipeline installations and other equipment	(3,883,879)	(544,907)	676	34,121	167	(4,393,822)
Refineries	(2,139,241)	(223,626)	-	13,722	11	(2,349,134)
Buildings	(426,461)	(59,431)	492	8,136	247	(477,017)
Ships and aircrafts	(675,211)	(101,882)	-	849	409	(775,835)
Moveable assets	(883,826)	(106,150)	4,229	21,281	(5,216)	(969,682)
Sub-total	(8,009,315)	(1,035,996)	5,397	77,928	(4,380)	(8,966,366)
Finance lease assets:						
Land rights	(70,578)	(12,294)	-	-	-	(82,872)
Buildings	(50,506)	(8,396)	-	-	-	(58,902)
Tanks, pipeline installations and other equipment	(165,624)	(34,098)	-	(11,064)	-	(210,786)
Moveable assets	(121,208)	(9,216)	-	(4,432)	1,190	(133,666)
Sub-total	(407,916)	(64,004)	-	(15,496)	1,190	(486,226)
Total accumulated depreciation	**(8,417,231)**	**(1,100,000)**	**5,397**	**62,432**	**(3,190)**	**(9,452,592)**
Provision for impairment	(49,697)	(7,364)	-	-	6	(57,055)
Net book value	**12,156,785**					**12,439,511**

13. FIXED ASSETS (continued)

	December 31, 2016					
	Beginning balance	Additions	Deductions	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost:						
Direct acquisition:						
Land and land rights	1,113,305	3,237	(939)	544,045	3,468	1,663,116
Tanks, pipeline installations and other equipment	7,015,411	12,777	(11,277)	1,208,973	714	8,226,598
Refineries	4,487,794	-	-	(671,900)	38	3,815,932
Buildings	841,550	18,364	(20,161)	156,743	6,559	1,003,055
Ships and aircrafts	1,800,419	41,322	-	49,316	3,209	1,894,266
Moveable assets	1,381,379	101,011	(15,858)	97,441	(4)	1,563,969
Assets under construction	1,939,028	986,629	(33,639)	(1,099,905)	128	1,792,241
Sub-total	18,578,886	1,163,340	(81,874)	284,713	14,112	19,959,177
Finance lease assets:						
Land rights	122,815	-	-	-	-	122,815
Buildings	83,987	-	-	-	-	83,987
Tanks, pipeline installations and other equipment	272,691	32,876	-	-	-	305,567
Moveable assets	190,330	4,514	(202)	(42,254)	(221)	152,167
Sub-total	669,823	37,390	(202)	(42,254)	(221)	664,536
Total acquisition cost	**19,248,709**	**1,200,730**	**(82,076)**	**242,459**	**13,891**	**20,623,713**
Accumulated depreciation:						
Direct acquisition:						
Land rights	(504)	(188)	-	-	(5)	(697)
Tanks, pipeline installations and other equipment	(3,025,001)	(391,058)	548	(467,954)	(414)	(3,883,879)
Refineries	(1,937,916)	(225,810)	-	24,511	(26)	(2,139,241)
Buildings	(388,353)	(43,391)	10,546	(5,536)	273	(426,461)
Ships and aircrafts	(675,123)	(96,221)	-	96,723	(590)	(675,211)
Moveable assets	(770,756)	(170,185)	11,433	51,518	(5,836)	(883,826)
Sub-total	(6,797,653)	(926,853)	22,527	(300,738)	(6,598)	(8,009,315)
Finance lease assets:						
Land rights	(58,182)	(12,396)	-	-	-	(70,578)
Buildings	(42,088)	(8,418)	-	-	-	(50,506)
Tanks, pipeline installations and other equipment	(138,503)	(27,121)	-	-	-	(165,624)
Moveable assets	(107,256)	(25,064)	-	6,915	4,197	(121,208)
Sub-total	(346,029)	(72,999)	-	6,915	4,197	(407,916)
Total accumulated depreciation	**(7,143,682)**	**(999,852)**	**22,527**	**(293,823)**	**(2,401)**	**(8,417,231)**
Provision for impairment	(44,354)	(7,151)	-	1,808	-	(49,697)
Net book value	**12,060,673**					**12,156,785**

The allocation of depreciation expenses are as follows:

	For the nine-month period ended September 30, 2019 (unaudited)	For the years ended December 31,		
		2018	2017	2016
Cost of goods sold (Note 32)	390,593	566,412	551,911	501,823
Expenses from other operating activities (Note 35)	67,896	88,405	84,636	77,454
Selling and marketing expenses (Note 36)	277,548	328,695	362,241	313,688
General and administrative expenses (Note 37)	86,643	97,655	101,212	106,887
Total	**822,680**	**1,081,167**	**1,100,000**	**999,852**

13. FIXED ASSETS (continued)

As of September 30, 2019, the Group owned parcels of land at various locations in Indonesia with Building Rights Title ("HGB") ranging from 20-30 years. Some of the HGBs are near their expiration dates. Management believes that those HGB licenses can be extended upon their expirations.

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the Group's inventories, investment properties, fixed assets, and oil & gas and geothermal properties, except for land and land rights (Notes 10, 12, 13, and 14), were insured against fire and other possible risks for a total insurance coverage of US$53,891,556, and US$53,391,900, US$50,430,767 and US$46,056,456 respectively.

Management believes that the insurance coverage is adequate to cover any possible losses that may arise in relation to the insured assets.

Certain fixed assets were pledged as collateral for certain subsidiary short term loan and long term loans (Notes 5, 16 and 20a).

Interest capitalized as part of fixed assets for the nine-month period ended September 30, 2019, and the years ended December 31, 2018, 2017, and 2016 amounting to US$13,205, and US$31,500, US$25,611, and US$16,689 respectively.

Management believes that the provision for impairment in the value of fixed assets as of September 30, 2019, and December 31, 2018, 2017, and 2016 is adequate to cover any possible losses from impairment of fixed assets.

Assets under construction as of September 30, 2019, and December 31, 2018, 2017, and 2016 consists of refineries, buildings, vessels, installations and moveable assets.

14. OIL AND GAS AND GEOTHERMAL PROPERTIES

	September 30, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost:					
Direct Acquisition:					
Land and land rights	18,281	-	-	41	18,322
Oil and gas wells	15,461,845	123,486	-	1,434,586	17,019,917
Geothermal wells	759,351	-	-	15,219	774,570
Installations	7,675,508	91,372	(190)	(162,637)	7,604,053
LPG plants	1,538,366	587	-	(4,808)	1,534,145
Buildings	198,613	-	-	5,793	204,406
Moveable assets	418,511	-	-	10,981	429,492
Sub-total	26,070,475	215,445	(190)	1,299,175	27,584,905
Assets under construction:					
Exploratory and evaluation wells	1,380,730	416,368	(102,111)	175,042	1,870,029
Development wells	2,423,499	1,176,416	-	(928,014)	2,671,901
Sub-total	3,804,229	1,592,784	(102,111)	(752,972)	4,541,930
Finance lease assets:					
Installations	4,672	-	-	-	4,672
LPG plants	12,501	-	(6,335)	(6,166)	-
Buildings	19,939	-	-	-	19,939
Moveable assets	195,595	-	-	-	195,595
Sub-total	232,707	-	(6,335)	(6,166)	220,206
Total acquisition cost	**30,107,411**	**1,808,229**	**(108,636)**	**540,037**	**32,347,041**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	September 30, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization:					
Direct Acquisition:					
Oil and gas wells	(7,076,161)	(1,102,150)	-	(592,195)	(8,770,506)
Geothermal wells	(152,127)	(29,632)	-	-	(181,759)
Installations	(2,717,802)	(244,240)	-	2,427	(2,959,615)
LPG plants	(293,601)	(60,443)	-	-	(354,044)
Buildings	(48,441)	(9,918)	-	-	(58,359)
Moveable assets	(244,360)	(42,591)	-	-	(286,951)
Sub-total	(10,532,492)	(1,488,974)	-	(589,768)	(12,611,234)
Finance lease assets:					
Installations	(18,723)	-	-	6,708	(12,015)
LPG plants	(5,777)	-	6,335	(558)	-
Buildings	(18,522)	(183)	-	-	(18,705)
Moveable assets	(181,398)	-	-	7,057	(174,341)
Sub-total	(224,420)	(183)	6,335	13,207	(205,061)
Total accumulated depreciation, depletion and amortization	**(10,756,912)**	**(1,489,157)**	**6,335**	**(576,561)**	**(12,816,295)**
Provision for impairment	(736,213)	(109,692)	283	(1,338)	(846,960)
Net book values	**18,614,286**				**18,683,786**

	December 31, 2018				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost:					
Direct Acquisition:					
Land and land rights	18,243	-	-	38	18,281
Oil and gas wells	13,915,574	1,116,330	(107,073)	537,014	15,461,845
Geothermal wells	671,595	4,671	-	83,085	759,351
Installations	7,213,878	109,761	(1,195)	353,064	7,675,508
LPG plants	1,538,366	-	-	-	1,538,366
Buildings	173,184	1,152	-	24,277	198,613
Moveable assets	346,955	39,034	-	32,522	418,511
Sub-total	23,877,795	1,270,948	(108,268)	1,030,000	26,070,475
Assets under construction:					
Exploratory and evaluation wells	1,326,425	606,380	(120,381)	(431,694)	1,380,730
Development wells	2,096,876	1,163,019	(4,519)	(831,877)	2,423,499
Sub-total	3,423,301	1,769,399	(124,900)	(1,263,571)	3,804,229
Finance lease assets:					
Installations	4,672	-	-	-	4,672
LPG plants	12,501	-	-	-	12,501
Buildings	19,939	-	-	-	19,939
Moveable assets	195,595	-	-	-	195,595
Sub-total	232,707	-	-	-	232,707
Total acquisition cost	**27,533,803**	**3,040,347**	**(233,168)**	**(233,571)**	**30,107,411**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2018				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization:					
Direct Acquisition:					
Oil and gas wells	(6,096,976)	(965,091)	38,038	(52,132)	(7,076,161)
Geothermal wells	(113,904)	(38,223)	-	-	(152,127)
Installations	(2,121,664)	(586,590)	-	(9,548)	(2,717,802)
LPG plants	(179,681)	(113,920)	-	-	(293,601)
Buildings	(36,698)	(11,743)	-	-	(48,441)
Moveable assets	(214,002)	(30,358)	-	-	(244,360)
Sub-total	(8,762,925)	(1,745,925)	38,038	(61,680)	(10,532,492)
Finance lease assets:					
Installations	(16,695)	(2,028)	-	-	(18,723)
LPG plants	(5,469)	(308)	-	-	(5,777)
Buildings	(18,198)	(324)	-	-	(18,522)
Moveable assets	(181,118)	(280)	-	-	(181,398)
Sub-total	(221,480)	(2,940)	-	-	(224,420)
Total accumulated depreciation, depletion and amortization	**(8,984,405)**	**(1,748,865)**	**38,038**	**(61,680)**	**(10,756,912)**
Provision for impairment	(518,024)	(218,189)	-	-	(736,213)
Net book values	**18,031,374**				**18,614,286**

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost:					
Direct Acquisition:					
Land and land rights	17,651	-	-	592	18,243
Oil and gas wells	10,936,067	2,030,494	(172,042)	1,121,055	13,915,574
Geothermal wells	473,810	-	-	197,785	671,595
Installations	6,345,909	138,748	(144)	729,365	7,213,878
LPG plants	1,435,050	-	-	103,316	1,538,366
Buildings	139,738	2,054	-	31,392	173,184
Moveable assets	306,208	9,942	-	30,805	346,955
Sub-total	19,654,433	2,181,238	(172,186)	2,214,310	23,877,795
Assets under construction:					
Exploratory and evaluation wells	1,851,229	463,671	(85,882)	(902,593)	1,326,425
Development wells	1,769,156	1,190,713	-	(862,993)	2,096,876
Sub-total	3,620,385	1,654,384	(85,882)	(1,765,586)	3,423,301
Finance lease assets:					
Installations	21,260	-	(16,588)	-	4,672
LPG plants	28,163	-	-	(15,662)	12,501
Buildings	19,962	-	-	(23)	19,939
Moveable assets	195,572	-	-	23	195,595
Sub-total	264,957	-	(16,588)	(15,662)	232,707
Total acquisition cost	**23,539,775**	**3,835,622**	**(274,656)**	**433,062**	**27,533,803**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization:					
Direct Acquisition:					
Oil and gas wells	(4,582,073)	(914,618)	103,496	(703,781)	(6,096,976)
Geothermal wells	(81,462)	(32,442)	-	-	(113,904)
Installations	(1,592,282)	(529,382)	-	-	(2,121,664)
LPG plants	(105,817)	(58,200)	-	(15,664)	(179,681)
Buildings	(26,761)	(9,937)	-	-	(36,698)
Moveable assets	(176,852)	(37,150)	-	-	(214,002)
Sub-total	(6,565,247)	(1,581,729)	103,496	(719,445)	(8,762,925)
Finance lease assets:					
Installations	(31,060)	(2,223)	16,588	-	(16,695)
LPG plants	(20,517)	(617)	-	15,665	(5,469)
Buildings	(17,787)	(411)	-	-	(18,198)
Moveable assets	(180,831)	(287)	-	-	(181,118)
Sub-total	(250,195)	(3,538)	16,588	15,665	(221,480)
Total accumulated Depreciation, depletion and amortization	**(6,815,442)**	**(1,585,267)**	**120,084**	**(703,780)**	**(8,984,405)**
Provision for impairment	(326,671)	(234,614)	43,261	-	(518,024)
Net book values	**16,397,662**				**18,031,374**

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost:					
Direct Acquisition:					
Land and land rights	13,534	-	-	4,117	17,651
Oil and gas wells	10,436,456	2,700	(129,637)	626,548	10,936,067
Geothermal wells	220,559	-	-	253,251	473,810
Installations	4,873,154	294,576	(1,400)	1,179,579	6,345,909
LPG plants	1,297,778	-	-	137,272	1,435,050
Buildings	79,319	-	-	60,419	139,738
Moveable assets	262,695	8	-	43,505	306,208
Sub-total	17,183,495	297,284	(131,037)	2,304,691	19,654,433
Assets under construction:					
Exploratory and evaluation wells	2,275,234	973,555	(22,437)	(1,375,123)	1,851,229
Development wells	2,047,230	541,176	(25,091)	(794,159)	1,769,156
Sub-total	4,322,464	1,514,731	(47,528)	(2,169,282)	3,620,385
Finance lease assets:					
Installations	74,804	-	(15,977)	(37,567)	21,260
LPG plants	44,218	-	(6,591)	(9,464)	28,163
Buildings	19,962	-	-	-	19,962
Moveable assets	195,572	-	-	-	195,572
Sub-total	334,556	-	(22,568)	(47,031)	264,957
Total acquisition cost	**21,840,515**	**1,812,015**	**(201,133)**	**88,378**	**23,539,775**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization:					
Direct Acquisition:					
Oil and gas wells	(3,531,941)	(1,053,549)	43,899	(40,482)	(4,582,073)
Geothermal wells	(62,993)	(18,469)	-	-	(81,462)
Installations	(1,131,437)	(366,024)	105	(94,926)	(1,592,282)
LPG plants	(37,789)	(68,028)	-	-	(105,817)
Buildings	(19,611)	(7,150)	-	-	(26,761)
Moveable assets	(141,194)	(35,658)	-	-	(176,852)
Sub-total	(4,924,965)	(1,548,878)	44,004	(135,408)	(6,565,247)
Finance lease assets:					
Installations	(242,247)	(22,645)	15,977	217,855	(31,060)
LPG plants	(35,955)	(616)	6,591	9,463	(20,517)
Buildings	(17,289)	(498)	-	-	(17,787)
Moveable assets	(241)	(302)	-	(180,288)	(180,831)
Sub-total	(295,732)	(24,061)	22,568	47,030	(250,195)
Total accumulated depreciation, depletion and amortization	**(5,220,697)**	**(1,572,939)**	**66,572**	**(88,378)**	**(6,815,442)**
Provision for impairment	(140,055)	(186,616)	-	-	(326,671)
Net book values	**16,479,763**				**16,397,662**

The allocation of depreciation, depletion and amortization expenses are as as follows:

	For the nine-month period ended September 30, 2019 (unaudited)	For the years ended December 31,		
		2018	2017	2016
Upstream production and lifting costs (Note 33)	1,482,889	1,741,040	1,578,988	1,568,663
General and administrative expenses (Note 37)	6,268	7,825	6,279	4,276
Total	**1,489,157**	**1,748,865**	**1,585,267**	**1,572,939**

As of September 30, 2019, and December 31, 2018, 2017, and 2016, all of the PGE's, PEP, and PGN properties, except land and land rights, were insured against fire and other possible risks (Note 13).

Management believes that the insurance coverage is adequate to cover any possible losses that may arise in relation to the insured oil and gas and geothermal properties.

The increase in the value of oil and gas wells in 2018 and 2017 respectively, resulted from the payment of the Rokan PSC signature bonus (Note 4g) and the consolidation of Maurel et Prom's Etablissements SA.

Impairment of oil and gas properties

Estimated recoverable amounts and book values of the oil and gas properties impaired as of September 30, 2019, and December 31, 2018, 2017, and 2016 are as follows:

	September 30, 2019 (unaudited)				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	416,580	482,087	65,507	-	65,507
PGN and its subsidiaries	596,498	640,683	44,185	-	44,185
Net book value	**1,013,078**	**1,122,770**	**109,692**	**-**	**109,692**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2018				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	173,488	366,793	193,305	-	193,305
Pertamina EP Cepu ADK	55,046	53,708	(1,338)	-	(1,338)
PGN and its subsidiaries	872,528	898,750	26,222	-	26,222
Net book value	**1,101,062**	**1,319,251**	**218,189**	**-**	**218,189**

	December 31, 2017				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	856,112	1,097,805	241,693	6,890	234,803
PIEP and its subsidiaries	740,580	708,003	(32,577)	-	(32,577)
Pertamina EP Cepu	58,888	-	(58,888)	-	(58,888)
Pertamina EP Cepu ADK	8,817	63,864	55,047	-	55,047
PGN and its subsidiaries	842,735	835,703	(7,032)	-	(7,032)
Net book value	**2,507,132**	**2,705,375**	**198,243**	**6,890**	**191,353**

	December 31, 2016				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	195,539	249,976	54,437	-	54,437
PIEP and its subsidiaries	799,761	972,115	172,354	136,264	36,090
Pertamina EP Cepu	-	58,888	58,888	-	58,888
PGN and its subsidiaries	802,565	839,766	37,201	-	37,201
Net book value	**1,797,865**	**2,120,745**	**322,880**	**136,264**	**186,616**

15. OTHER NON-CURRENT ASSETS

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Restricted funds	1,093,068	950,052	878,821	662,751
Government contributed assets pending final clarification of status (Note 26)	398,557	401,120	1,361	-
Advances to vendors	308,701	133,406	217,704	71,773
Prepaid expenses	105,122	65,319	31,601	41,422
Other receivables - third parties	96,201	80,287	243,786	135,481
Finance lease receivables	78,957	200,770	208,908	222,589
Goodwill	53,807	53,807	53,807	60,697
Other receivables related parties (Note 41b)	37,739	64,907	80,349	86,232
Long-term employee receivables	37,074	37,530	45,652	39,828
Land rights costs	18,100	18,917	21,653	21,837
Deferred charges	17,042	17,256	92,834	57,864
Intangible assets	13,107	13,711	17,771	18,039
Assets held but not used for operation	4,536	23,454	24,819	10,210
Non-free and non-clear assets	1,837	1,837	1,837	1,837
Others	71,465	22,960	56,567	6,304
Total	**2,335,313**	**2,085,333**	**1,977,470**	**1,436,864**

15. OTHER NON-CURRENT ASSETS (continued)

a. Restricted funds

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
US dollar accounts				
Government-related entities				
- BRI	357,338	321,620	263,638	252,926
- BNI	58,535	50,016	-	-
- Bank Mandiri	70,193	14,030	47,038	39,290
Third parties				
- JP Morgan	31,087	31,087	24,661	-
- BCA	75	-	-	-
- Others	1,186	540	-	-
	518,414	417,293	335,337	292,216
Indonesian rupiah accounts				
Government-related entities				
- BRI	308,713	290,500	296,096	212,064
- Bank Mandiri	254,923	233,993	238,692	157,564
- BNI	1,564	840	899	907
- PT Bank Pembangunan Daerah Jawa Barat dan Banten Tbk.	353	-	-	-
- BTN	353	-	-	-
- BRI Agro	77	-	-	-
- Others	705	-	-	-
Third parties				
- PT Bank Mega Tbk.	7,332			
- BCA	259			
- Others	375	7,426	7,797	-
	574,654	532,759	543,484	370,535
Total	**1,093,068**	**950,052**	**878,821**	**662,751**

In accordance with SKK Migas instructions, as of September 30, 2019, and December 31, 2018, 2017, and 2016 PT Pertamina EP deposited for decommissioning funds, site restoration, and other related activities in joint bank accounts held by SKK Migas and PT Pertamina EP in BRI and Mandiri in the amounts of US$293,508, US$275,660, US$252,501 and US$223,984, respectively. PT Pertamina Internasional Eksplorasi dan Produksi ("PIEP") for PT Pertamina Malaysia EP ("PMEP") deposited funds for decommissioning, site restoration and other related activities in a joint bank account as of September 30, 2019 and December 31, 2018 in the amount of US$55,320 and US$54,329, respectively.

The Company has created reserves fund for past service liabilities to employees as of September 30, 2019, and December 31, 2018, 2017, and 2016 amounting to Rp7,880,736 million (equivalent to US$555,999), Rp7,534,125 million (equivalent to US$520,277), Rp7,185,952 million (equivalent to US$530,407), and Rp4,911,848 million (equivalent to US$365,574), respectively.

As of September 30, 2019, and December 31, 2018, 2017, and 2016, restrained fund for Partnership Program amounting to Rp12,174 million (equivalent to US$859), Rp12,174 million (equivalent to US$840), Rp12,174 million (equivalent to US$899), and Rp12,174 million (equivalent to US$907), respectively.

As of September 30, 2019, restrained fund for Community Development Program amounting to Rp63,444 million (equivalent to US$4,476).

Included in restricted cash are time deposits which are used as guarantees for operational working contracts in PT Pertamina Bina Medika IHC (formerly PT Pertamina Bina Medika), and PIEP.

b. Advances to vendors - net

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Advances to vendors	341,405	166,110	250,408	104,477
Provision for impairment	(32,704)	(32,704)	(32,704)	(32,704)
Net	**308,701**	**133,406**	**217,704**	**71,773**

15. OTHER NON-CURRENT ASSETS (continued)

b. Advances to vendors - net (continued)

On September 27, 2019, the Company made advance payments for the Engineering, Procurement and Construction ("EPC") Inside Battery Limit ("ISBL") and Outside Battery Limit ("OSBL") Refinery Development Master Plan ("RDMP") Project RU-V Balikpapan amounted to US$199,915. These payments were based on (Note 49m) the EPC ISBL & OSBL First Amendment Contract No. 25/C000002/2018 dated September 5, 2019.

The Company has recognized a provision for impairment to reduce an advance to vendor for oil tanker construction contract with capacity of 30,000 LTDW between the Company and Zhejiang Chenye Shipbuilding Co. Ltd. Management believes that the provision for impairment is adequate to cover possible losses.

c. Finance lease receivables

This account represents the non-current portion of the finance lease receivables from lease arrangement between PT Kalimantan Jawa Gas ("KJG"), PGN's subsidiary, and PT Perusahaan Listrik Negara ("PLN") (Persero) in relation to KJG's subsea pipelines and onshore receiving facility on land Gas Transport Agreement ("GTA") Kalija 1 which is classified as a finance lease transaction.

d. Goodwill

	Beginning balance	Addition	Deduction	Ending balance
September 30, 2019 (unaudited)				
PHE ONWJ	53,337	-	-	53,337
PHE Nunukan Company	415	-	-	415
PGN and its subsidiaries	55	-	-	55
Total	**53,807**	**-**	**-**	**53,807**
December 31, 2018				
PHE ONWJ	53,337	-	-	53,337
PHE Nunukan Company	415	-	-	415
PGN and its subsidiaries	55	-	-	55
Total	**53,807**	**-**	**-**	**53,807**
December 31, 2017				
PHE ONWJ	53,337	-	-	53,337
PHE Tuban	4,538	-	(4,538)	-
PGN and its subsidiaries	55	-	-	55
Others	2,767	-	(2,352)	415
Total	**60,697**	**-**	**(6,890)**	**53,807**
December 31, 2016				
COPAL	136,264	-	(136,264)	-
PHE ONWJ	53,337	-	-	53,337
PHE Tuban	4,538	-	-	4,538
PGN and its subsidiaries	55	-	-	55
Others	2,767	-	-	2,767
Total	**196,961**	**-**	**(136,264)**	**60,697**

The goodwill is allocated to the Company's identified Cash Generating Unit ("CGU").

The Group calculated the recoverable amounts based on fair value less cost to sell model which provides a higher value than the value-in-use calculation. The fair value less cost to sell was determined by using a post-tax discounted cash flows ("DCF") calculation.

The cash flows projections are based on production and development forecast approved by management covering the estimated period of contract including contract extension and future investments to increase output. The period of projections ranges from 3-30 years.

ONWJ, PHE Tuban and Other
The Group acquired PT Medco E&P Tuban (subsequently changed its name to PT PHE Tuban) in 2008 and BP West Java Ltd., (subsequently changed its name to ONWJ Ltd.) in 2009, PT PHE Oil and Gas ("PHE OG") and other acquisition in 2013. The Group has recorded an impairment in the value of goodwill in 2019 and 2018 amounting to nill, 2017 amounting to US$4,538 and US$2,352 (Note 39), from the PHE Blok Tuban and Ambalat Block, respectively to the carrying value of PHE OG.

15. OTHER NON-CURRENT ASSETS (continued)

d. Goodwill (continued)

PGN and its subsidiaries
In 2013, PT PGAS Telekomunikasi Nusantara ("PGASKOM"), a subsidiary of PGN, acquired 100% equity interest of PT Telemedia Dinamika Sarana ("TDS") with consideration paid amounting to Rp675 million (or equivalent to US$55). PGASKOM recognized goodwill from this acquisition amounting to US$55.

COPAL
Effective on November 27, 2013, the Company acquired 100% shares of COPAL from Burlington Resources International Holdings LLC with consideration paid of US$1,669,892. COPAL is a corporation domiciled in the Caymand Island and holds 65% participating interest in Block 405a Algeria. The Company recognized goodwill from this acquisition in the amount of US$556,703. As of January 1, 2016/December 31, 2015, the Group has recorded impairment loss on COPAL goodwill with total cumulative amount of US$420,439.

The Group has recorded impairment losses on goodwill for the year ended December 31, 2017 and 2016 amounting to US$6,890 from PHE (Block Tuban and Block Ambalat) and US$136,264 from COPAL, respectively.

The key assumption relates to oil and gas price, was projected based on expectation of market development given the volatility in oil prices. The discount rate used reflects risk relating to the relevant oil and gas industry and considering risks of individual country of operations.

Key assumptions used for the basis of the impairment test on September 30, 2019 are as follows:

	Assumptions 2019				
	2019 (unaudited)	2020	2021	2022	2023
Projected ICP	US$61.50	US$61.50	US$62.50	US$63.60	US$65.10
Projected Brent	US$65.00	US$65.00	US$66.00	US$67.10	US$68.50

Then increases by US$1.00 - US$1.70 per annum either for ICP or Brent.

Gas price	Based on the gas sales agreement
Discount rate	6.75%-10.90%

Management believes the goodwill impairment is sufficient based on the result of the impairment testing.

e. Non-free and non-clear assets - net

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Non-free and non-clear assets	112,237	112,237	112,237	112,237
Provision for impairment	(110,400)	(110,400)	(110,400)	(110,400)
Net	**1,837**	**1,837**	**1,837**	**1,837**

Non-free and non-clear assets represent land plots located in Teluk Semangka, Lampung and certain assets located in other areas where, as of the date of the completion of these consolidated financial statements, the documentation and rights of the Company were still subject to completion of the legal and settlement processes to allow the Company to fully utilize such assets.

The Company has recognized a provision for impairment to reduce the value of such assets to their recoverable amounts. Management believes that the provision for impairment is adequate.

16. SHORT-TERM LOANS

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Government-related entities (Note 41)				
- Bank Mandiri	956,118	1,705,709	166,151	41,937
- BRI	359,981	820,154	189,027	4,434
- BNI	50,219	638,751	340	412
- Others (each bellow US$10,000)	3,740	110	-	726
Third parties				
- The Bank of Tokyo Mitsubishi UFJ, Ltd. (“BOTM”)	313,573	-	-	-
- HSBC	149,880	67,075	-	-
- PT Bank Mizuho Indonesia	71,734	203,272	10,000	-
- Sumitomo Mitsui Banking Corporation	9,000	97,016	10,000	6,425
- PT Bank UOB Indonesia	1,969	-	10,000	10,000
- PT Bank ICBC Indonesia	1,594	23,974	27,292	25,642
- PT Bank Sumitomo Mitsui Indonesia	-	145,368	-	50,000
- Citibank,N.A	-	145,344	-	-
- PT ANZ Panin Bank	-	139,491	-	-
- BCA	-	118,934	-	4
- Deutsche Bank AG	-	93,970	32,285	39,761
- PT Bank DBS Indonesia	-	86,842	-	50,952
- PT Bank Permata Tbk.	-	59,804	-	-
- PT Bank CIMB Niaga	-	-	5,735	-
- BNP Paribas	-	-	1,329	-
- Others (each bellow US$10,000)	478	1,221	720	-
Total	**1,918,286**	**4,347,035**	**452,879**	**230,293**

Other information relating to the Group’s short-term bank loan facilities as of September 30, 2019 are as follows:

Lenders	Expiration date
Bank Mandiri	September 30, 2020
BNI	July 3, 2020
BRI	March 24, 2020
Sumitomo Mitsui Banking Corporation	March 29, 2020
PT Bank Mizuho Indonesia	April 23, 2020
The Hongkong and Shanghai Banking Group (HSBC)	August 31, 2020
PT Bank ICBC Indonesia	December 31, 2019
The Bank of Tokyo-Mitsubishi UFJ, Ltd. (BOTM)	January 11, 2020
PT Bank UOB Indonesia	January 3, 2020

Interest rates charged are based on market rates (e.g. Singapore Interbank Offered Rate (“SIBOR”) or London Interbank Offered Rate (“LIBOR”)) plus certain percentage depending on negotiation at drawdown.

The interest rates on short-term loans for the nine-month period ended September 30, 2019 and for the years ended December 31, 2018, 2017, and 2016 are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
US dollar	2.70%-7.25%	2.76%-3.71%	1.42%-2.52%	1.44%-1.65%
Indonesian Rupiah	7.25%-9.75%	7.25%-11.50%	6.40%-12.50%	5.19%-12.75%

The funds received from short-term loans are to be used for working capital purposes.

17. TRADE PAYABLES - THIRD PARTIES

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
US dollar	2,561,826	3,215,103	3,719,566	3,050,556
Indonesian rupiah	720,526	374,194	152,548	213,848
Others	14,275	8,480	28,007	26,261
Total	**3,296,627**	**3,597,777**	**3,900,121**	**3,290,665**

The Group's trade payables are mainly related to purchases of crude oil, natural gas and petroleum products.

18. DUE TO THE GOVERNMENT

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
The Company:				
Conversion account (amount due to the Government for its share in the Indonesian crude oil production supplied to the Company's refineries)	1,021,004	961,481	749,956	586,171
Ulubelu and Lahendong geothermal project loan	253,310	253,310	252,123	200,777
Dividends payable to the Government	243,403	-	-	-
Lumut Balai geothermal project loan	99,450	84,594	47,590	36,798
The Government's share in the domestic natural gas sales including its share of Indonesian gas production	15,332	36,889	30,674	29,470
Payable for purchase of the Government's share in the LPG production	3,069	11,358	8,826	5,939
Ngurah Rai Airport refuelling facility construction project loan	4,610	4,505	5,152	5,697
Due to BPH Migas for retribution fee from distribution of BBM - non subsidy	-	-	-	4,163
Other liability	-	-	174,907	209,175
Total - Company	**1,640,178**	**1,352,137**	**1,269,228**	**1,078,190**
Subsidiaries:				
PT Pertamina EP				
Government's share of production	4,979	25,764	1,897	15,867
Finance lease liability state-owned assets	93,648	81,815	88,536	90,218
Sub-total	98,627	107,579	90,433	106,085
PT Pertamina Hulu Energi				
Overlifting payables	14,687	37,878	59,678	59,347
PT Pertamina Hulu Indonesia				
Overlifting payables	202,735	109,126	-	-
PT Pertamina EP Cepu				
Overlifting payables	-	-	-	18,875
PT Perusahaan Gas Negara Tbk.				
Loan for the construction of gas transmission pipelines from South Sumatera to West Java and distribution pipelines in West Java	346,520	352,971	360,034	362,178
Domestic Gas market development project loan	31,859	36,008	39,996	43,816
Gas transmition and distribution project Phase II project loan	4,751	7,126	11,876	16,627
Total - Subsidiaries	**699,179**	**650,688**	**562,017**	**606,928**
Total consolidated (Note 41)	**2,339,357**	**2,002,825**	**1,831,245**	**1,685,118**
Current portion	**(1,520,667)**	**(1,207,743)**	**(1,050,619)**	**(952,545)**
Non-current portion	**818,690**	**795,082**	**780,626**	**732,573**

18. DUE TO THE GOVERNMENT (continued)

a. Conversion account

The conversion account represents the Company's liability to the Government in relation to the shipment of the Government's share of Indonesian crude oil production to the Company's refineries for processing to meet the domestic demand for fuel products. The Government's share in the production of Indonesian crude oil derives from the work areas of the PSC contractors.

The movements of the conversion account are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	961,481	749,956	586,171	341,062
Add:				
Current year's Government share in the Indonesian crude oil production delivered to the Company's refineries during the year	6,576,945	10,289,631	6,819,294	4,726,374
Less:				
Cash settlement	(6,299,142)	(10,029,737)	(6,641,271)	(4,455,821)
Gains on foreign exchange	(218,280)	(48,369)	(14,238)	(25,444)
Ending balance	**1,021,004**	**961,481**	**749,956**	**586,171**

b. Ulubelu and Lahendong Geothermal project loan

For the implementation of Ulubelu and Lahendong Geothermal Clean Energy Investment Project, the Company has obtained loans from the International Bank for Reconstruction and Development ("IBRD") as part of the World Bank Loan.

On December 5, 2011, LA 8082-ID and TF10417-ID were signed by the Government of Indonesia and IBRD with the Company as Executing Agency and PGE as Implementing Agency, with total amount of US$300,000 consisting of LA 8082-ID of US$175,000 and LA TF10417-ID of US$125,000. Interest rate from World Bank is at LIBOR + 0.45% + 0.5% (bank charges) + variance spread annually, while interest rate from Japan International Cooperation Agency ("JICA") is at 0.25% + 0.25%.

Repayment of the loan principal will be on a semi-annual basis, on April 10 and October 10, LA-8082-ID, from October 10, 2020 until October 10, 2035 and LA TF10417-ID, from October 10, 2021 until April 10, 2051.

The following are the oustanding loan balances as of September 30, 2019 and December 31, 2018, 2017, and 2016:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
LA 8082-ID	129,044	129,044	131,055	108,947
LA TF10417-ID	124,266	124,266	121,068	91,830
Total	**253,310**	**253,310**	**252,123**	**200,777**

c. Dividends payable

Based on the General Meeting of Shareholder dated May 31, 2019, the shareholder approved, among others, the utilization of 2018 net income of the Company as follow:

- Distribute of dividends of Rp7,950 billion or equialent to US$552,659.
- The remaining amount of US$1,974,113 were reserved to support operation and corporate development.

As of September 30, 2019, dividend paid was Rp2,500 billion or equivalent to US$178,469 the remaining amount of Rp3,450 billion or equivalent to US$243,403 has been accrued as dividend payable.

18. DUE TO THE GOVERNMENT (continued)

d. Lumut Balai geothermal project loan

On March 29, 2011, the Loan Agreement ("LA") IP-557 was signed between the Government of Indonesia, represented by the Director General of Debt Management, Ministry of Finance, and JICA, represented by the Chief Representative of JICA, with the Company as Executing Agency and PGE as Implementing Agency. The amount of the loan facility is ¥26,966,000,000 (full amount) with drawing period of eight years from the effective date with effective interest rates at 0.3% p.a plus 0.3% p.a and 0.01% p.a plus 0.01% p.a, respectively.

Repayment of the loan principal will be on a semi-annual basis, on March 20, and September 20, commencing on March 20, 2021 to March 2051. The outstanding loan balance as of September 30, 2019, and December 2018, 2017, and 2016 amounted to ¥10,731,145,558, ¥9,343,033,479, ¥5,363,082,289, and ¥4,284,146,996 (full amount), respectively or equivalent to US$99,450, US$84,594, US$47,590, and US$36,798, respectively.

e. Ngurah Rai Airport refueling facility construction project loan

On May 7, 2007, the Government channelled a loan amounting to ¥1,172,872,837 (full amount) from the Overseas Economic Cooperation Fund Japan to the Company in relation to the construction of the Ngurah Rai Airport refuelling facility in accordance with the loan agreement dated November 29, 1994.

The loan is repayable in 36 semi-annual installments commencing in May 2007 through November 2024, and is subject to interest at the rate of 3.1% per annum. The outstanding loan balance as of September 30, 2019 and December 31, 2018, 2017, and 2016 amounted to ¥497,492,834, ¥497,492,834, ¥580,408,306, and ¥663,323,781 (full amount), respectively, or equivalent to US$4,610, US$4,505, US$5,152, and US$5,697, respectively.

f. Finance lease liability involving state-owned assets utilized by PT Pertamina EP

In accordance with the Minister of Finance Decree dated May 2, 2008, assets previously owned by the former Pertamina Entity which have not been recognized in the opening balance sheet of the Company, represent state-owned assets ("BMN"), the control of which is exercised by the Directorate General of State Assets.

On September 20, 2016, the State Property Lease Agreements between the Ministry of Finance of the Republic of Indonesia with PT Pertamina EP No. PRJ-3-MK.6/2016 and No. 1307/EP0000/2016-S0 have been signed. With the signing of the agreements, management believes that the property lease payable for unutilized BMN, will not be charged by the Government since it was not included as part of the scope of the agreements. Therefore, in 2016, PT Pertamina EP made correction to the BMN lease payable for BMN which are not used by PT Pertamina EP.

The following table represents the finance lease payables to BMN that include installations, buildings, and moveable equipment utilized in the PT Pertamina EP's oil and gas operations:

Lessor	Type of asset	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
The Ministry of Finance	Installation assets, buildings and moveable assets	93,648	81,815	88,536	90,218
Less current portion		(12,316)	(1,180)	(1,087)	(944)
Non-current portion		**81,332**	**80,635**	**87,449**	**89,274**

18. DUE TO THE GOVERNMENT (continued)

f. Finance lease liability involving state-owned assets utilized by PT Pertamina EP (continued)

Future minimum lease payments as of September 30, 2019, and December 31, 2018, 2017, and 2016, are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Within one year	14,619	14,310	15,295	15,423
More than one year but not more than five years	58,478	71,550	76,475	77,112
More than five years	181,840	153,832	179,716	196,637
Total	254,937	239,692	271,486	289,172
Less interest	(161,289)	(157,877)	(182,950)	(198,954)
Net	93,648	81,815	88,536	90,218
Current portion	(12,316)	(1,180)	(1,087)	(944)
Non-current portion	**81,332**	**80,635**	**87,449**	**89,274**

g. Overlifting payables

The overlifting payables represent subsidiaries' payable to SKK Migas as a result of subsidiaries' actual lifting crude oil and gas being higher than their entitlements for the respective year.

h. Loans for the construction of gas transmission pipelines from South Sumatera to West Java and distribution pipelines in West Java

On March 27, 2003, Japan Bank for International Cooperation ("JBIC") agreed to provide loans to the Government with a total amount equivalent to ¥49,088,000,000 (full amount) to assist the Government in financing the construction of a gas transmission pipeline network from South Sumatra to Java West and distribution pipelines in West Java.

On May 28, 2003, PGN and the Government entered into a Loan Forwarding Agreement No. SLA1156/DP3/2003, where the Government continues this loan from JBIC with a total not exceeding ¥49,088,000,000 (full amount) to PGN.

The loan principal is repayable on semi-annually basis on March 20 and September 15 starting from March 20, 2013 to March 20, 2043. The loan balance as of September 30, 2019, and December 31, 2018, 2017, and 2016 amounted to ¥37,391,272,946, ¥38,983,847,840, ¥40,554,284,480, and ¥42,164,627,000 (full amounts), respectively or equivalent to US$346,520, US$352,971, US$360,034, and US$362,178, respectively.

i. Domestic Gas market development project loan

Based on the loan agreement dated February 7, 2006, IBRD agreed to provide loan facility to the Government an aggregate amount equivalent to US$80,000 to assist the Government in financing the Domestic Gas Market Development Project.

On April 3, 2006, PGN and the Government entered into the related Subsidiary Loan Agreement, which provides for the Government's relending of the IBRD loan proceeds of US$80,000 to PGN, which shall undertake the Project.

In December 2011, the total loan facility was changed to US$69,381,312. On November 14, 2013, PGN received Letter No. 5-786/PU/2013 from the Directorate General of Debt Management, Ministry of Finance of the Republic of Indonesia, regarding the approval for the cancellation of the remaining IBRD SLA 1201 loan amounting to US$7,616 starting on February 1, 2013.

The loan principal is repayable on semi-annually basis on February 15, and August 15 starting from April 3, 2006 to February 15, 2026. The loan balance as of September 30, 2019 and December 31, 2018, 2017, and 2016 US$31,859, US$36,008, US$39,996, and US$43,816.

18. DUE TO THE GOVERNMENT (continued)

j. Gas transmition and distribution project Phase II project loan

On September 15, 2000, PGN and the Government entered into a Loan Agreement, which provides for the Government's relending of the EIB loan proceeds not exceeding €70,000,000 (full amount) or equivalen to US$54,633 to PGN as part of the financing of the Gas Transmission and Distribution Project Phase II.

Under the Loan Agreement, PGN undertakes among other things, that it shall maintain certain financial covenants for each reporting year-end such as debt to equity ratio of maximum 2:1.

As of September 30, 2019 and December 31, 2018, 2017, and 2016 PGN has complied with all financial ratios required to be maintained under the loan agreements.

Payments towards the principal is done semi-annually on June 15, and December 15. Payment started from December 15, 2015 until June 15, 2020. The loan balances as of September 30, 2019 and December 31, 2018, 2017, and 2016 amounted to US$4,751, US$7,126, US$11,876, and US$16,627, respectively.

19. ACCRUED EXPENSES

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Suppliers and contractors	1,009,192	1,069,409	1,040,540	805,803
Estimated owned retention claim	571,854	286,508	190,458	123,423
Bonuses, incentives and salaries	302,238	441,536	460,779	398,874
Interest on loans	258,754	105,062	68,109	66,120
Employee benefits liabilities due within one year (Note 22b)	224,388	232,994	260,010	202,392
Total	**2,366,426**	**2,135,509**	**2,019,896**	**1,596,612**

20. LONG-TERM LIABILITIES

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Bank loans:				
Government-related entities (Note 41)	181,775	179,361	174,638	211,074
Third parties	1,701,542	1,891,264	2,100,822	3,028,748
	1,883,317	2,070,625	2,275,460	3,239,822
Issuance costs - net	(3,465)	(4,775)	(6,838)	(13,199)
Total bank loans - net	1,879,852	2,065,850	2,268,622	3,226,623
Finance leases	157,198	160,027	207,104	212,486
Total long-term liabilities	**2,037,050**	**2,225,877**	**2,475,726**	**3,439,109**
Current portion	**(529,521)**	**(420,577)**	**(365,959)**	**(722,200)**
Long-term liabilities - net of current portion	**1,507,529**	**1,805,300**	**2,109,767**	**2,716,909**

Annual interest rates on bank loans for the nine-month period ended September 30, 2019, and for the years ended December 31, 2018, 2017, and 2016 are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Indonesian rupiah	7.40%-9.75%	2.35%-13.00%	7.25%-13.00%	9.00%-12.50%
US dollar	1.37%-4.65%	1.37%-5.60%	1.37%-3.51%	1.46%-3.20%

20. LONG-TERM LIABILITIES (continued)

a. Bank loans

Details of the Group's syndicated and bank loans as of September 30, 2019, and December 31, 2018, 2017, and 2016 are as follows:

	September 30, 2019 (unaudited)		
	Total	Current	Non-current
Government-related entities			
Bank Mandiri	16,567	10,935	5,632
Bank Syariah Mandiri	9,329	3,918	5,411
BNI Syariah	5,879	157	5,722
Other financial institution - PT Multi Sarana Infrastruktur (Persero)	150,000	-	150,000
Third parties			
BOTM (Syndicated loan)	1,283,213	445,811	837,402
HSBC	233,000	-	233,000
Sumitomo Mitsui Banking Corporation	64,990	5,301	59,689
SMBC Indonesia	67,612	11,607	56,005
ICBC	50,839	9,486	41,353
Others (each below US$10,000)	1,888	1,888	-
Total	**1,883,317**	**489,103**	**1,394,214**

	December 31,								
	2018			2017			2016		
	Total	Current	Non-current	Total	Current	Non-current	Total	Current	Non-current
Government-related entities									
Bank Mandiri	19,753	10,043	9,710	17,463	15,981	1,482	14,996	2,967	12,029
Bank Syariah Mandiri	9,330	-	9,330	-	-	-	-	-	-
BNI	-	-	-	2,715	2,449	266	20,127	19,859	268
BRI	181	181	-	1,725	1,532	193	1,218	1,218	-
BNI Syariah	97	70	27	359	255	104	297	147	150
Other financial institution - PT Multi Sarana Infrastruktur (Persero)	150,000	-	150,000	150,000	-	150,000	150,000	-	150,000
Lembaga Pembiayaan Ekspor Indonesia	-	-	-	2,376	2,376	-	24,436	7,152	17,284
Third parties									
BOTM (Syndicated loan)	1,609,539	333,569	1,275,970	1,935,000	277,547	1,657,453	1,104,412	123,036	981,376
BNP Paribas	-	-	-	-	-	-	768,900	384,050	384,850
SMBC	199,318	10,601	188,717	105,575	10,602	94,973	1,117,426	130,000	987,426
SMBC Indonesia	67,407	9,083	58,324	60,247	7,273	52,974	29,518	-	29,518
PT Bank Mizuho Indonesia	-	-	-	-	-	-	2,438	2,438	-
ICBC	15,000	-	15,000	-	-	-	-	-	-
Others (each below US$10,000)				-	-	-	6,054	5,701	353
Total	**2,070,625**	**363,547**	**1,707,078**	**2,275,460**	**318,015**	**1,957,445**	**3,239,822**	**676,568**	**2,563,254**

20. LONG-TERM LIABILITIES (continued)

a. Bank loans (continued)

Other information on the Group's syndicated and bank loans as of September 30, 2019 is as follows:

Creditors	Repayment schedule
The Company	
SMBC (Long-term loan)	Several installments (2016-2025)
Other Financial Institutions	
PT Sarana Multi Infrastruktur (Persero)	
(Long-term loan)	Several installments (2015-2025)
BOTM (Syndicated loan)	Several installments (2016-2021)
Subsidiaries	
BNI Syariah	
PT Pertamina Trans Kontinental	Several installments (2019-2026)
SMBC Indonesia	
PT Pertamina Trans Kontinental	Several installments (2015-2024)
BOTM (Syndicated loans)	
PT Pertamina Trans Kontinental	Several installments (2018-2023)
Bank Mandiri	
PT Pelita Air Service	Several installments (2014-2021)
BOTM (Syndicated loans)	
PT Pertamina Internasional Eksplorasi dan Produksi	Several installments (2015-2023)
Bank Syariah Mandiri	
PT Pertamina International Shipping	Several installments (2018-2025)
Bank Mandiri	
PT Pertamina International Shipping	Several installments (2018-2025)
SMBC (Syndicated loans)	
PT Perusahaan Gas Negara Tbk.	Several installments (2015-2020)
ICBC	
PT Elnusa Tbk.	Several installments (2018-2023)
HSBC	
PT Pertamina EP Cepu	Several installments (2022-2034)

These bank loans are obtained to finance the capital expenditures of the Company and/or Subsidiaries' projects, general activities and certain costs relating to the agreement.

As specified by the loan agreements, the borrowers are required to comply with certain covenants, such as financial ratio covenants, no substantial change in the general business of the Company and/or Subsidiaries and not entering into mergers.

The certain subsidiaries' long-term bank loans are collateralised by those subsidiaries' receivables (Note 8) and fixed assets (Note 13).

On December 12, 2017, Etablissements Maurel et Prom SA entered entered into a syndicated loan agreement with 2 (two) national banks and 7 (seven) overseas banks. The Bank of Tokyo Mitsubishi UFJ, Ltd., Hong Kong Branch acting as Facility Agent. The syndicated loan facility amount is US$600 million bears interest at LIBOR plus 1.5% and shall be repaid on quarterly basis starting March 2020 to December 2023.

20. LONG-TERM LIABILITIES (continued)

a. Bank loans (continued)

Prior to effective date of the above syndicated loan agreement, on December 11, 2017, as required by syndication loan agreement, PIEP, as Sponsor, Maurel et Prom West Africa SA, as Borrower, and The Bank of Tokyo Mitsubishi UFJ, Ltd. Hongkong Branch as Facility Agent, signed the Sponsor Support Agreement. This Agreement stipulates that if the Borrower fails to fulfil its obligations (Borrower Non-Payment), the Borrower must immediately submit the Sponsor Loan Request Notice to the Sponsor, and the Sponsor is obligated to provide funds to the Borrower for all unsettled obligations including outstanding interest payable. On December 11, 2017, the Company has issued a comfort letter as required in the syndicated bank facilities as discussed above, but not constitute a guarantee in respect of the obligation of PIEP under Sponsor Support Agreement and the Company shall not be construed as acting as a guarantor.

On June 13, 2019, PEPC through a TBS obtained the following financing facilities for JTB project development with a total facility of US$1,846,400:

- Jambaran-Tiung Biru Loan Agreement, which was signed by the Trustee, MUFG Bank Ltd. as Agent and Lenders, with a total facility of US$700,000 from Tranche A and US$1,046,400 from Tranche B. The loan bears interest at a rate of LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B.
- Jambaran-Tiung Biru Wakala Agreement, which was signed by the Trustee and MUFG Bank (Malaysia) Berhad as Investment Agent, with a total facility of US$40,000 from Tranche A and US$60,000 from Tranche B. The loan bears interest at a rate of LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B.

The Tranche A loan principal is repayable on a semi-annual basis with the first payment due on March 31, 2022 and the final payment due on March 31, 2034. The Tranche B loan principal is repayable on a semi-annual basis with the first payment due on March 31, 2022 and the final payment due on March 31, 2029. Drawdown of the loan facilities have been made as of September 30, 2019 with total amount of US$233,000.

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the Group complied with the covenants as required by the loan agreements.

b. Finance leases

This account represents the Group's future minimum lease payments from finance lease transactions for the LPG Filling and Transport Stations ("SPPBEs"), landing craft transports, BBM and LPG truck tankers, computer servers, gas pipeline installations and LPG plants.

Future minimum lease payments as of September 30, 2019, and December 31, 2018, 2017, and 2016 are as follows:

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Within one year	52,064	84,137	54,407	55,501
Within more than year but not more than five years	134,994	115,474	121,179	161,754
More than five years	41,054	32,487	49,493	15,496
Total	228,112	232,098	225,079	232,751
Less: interest	(70,914)	(72,071)	(17,975)	(20,265)
Net	157,198	160,027	207,104	212,486
Current portion	(41,208)	(58,722)	(50,008)	(50,562)
Non-current portion	**115,990**	**101,305**	**157,096**	**161,924**

21. BONDS PAYABLE

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
The Company:				
Issued in 2011				
Due in 2021	1,000,000	1,000,000	1,000,000	1,000,000
Due in 2041	500,000	500,000	500,000	500,000
Issued in 2012				
Due in 2022	1,242,000	1,242,000	1,242,000	1,242,000
Due in 2042	1,221,590	1,221,590	1,230,000	1,230,000
Issued in 2013				
Due in 2023	1,615,000	1,615,000	1,615,000	1,615,000
Due in 2043	1,433,261	1,433,261	1,462,500	1,462,500
Issued in 2014				
Due in 2044	1,500,000	1,500,000	1,500,000	1,500,000
Issued in 2018				
Due in 2048	750,000	750,000	-	-
Issued in 2019				
Due in 2029	750,000	-	-	-
Due in 2049	750,000	-	-	-
Total	**10,761,851**	**9,261,851**	**8,549,500**	**8,549,500**
Discount	(65,722)	(65,722)	(51,180)	(51,180)
Issuance cost	(28,427)	(27,211)	(23,552)	(23,552)
Amortization of discount and issuance cost during the period/year	32,597	28,608	23,679	17,544
Bonds payable owned by subsidiaries:	(46,750)	(62,000)	(68,500)	(55,000)
Total Company	**10,653,549**	**9,135,526**	**8,429,947**	**8,437,312**
Subsidiaries:				
Senior Unsecured Fixed Rate Notes	1,350,000	1,350,000	1,350,000	1,350,000
PT Saka Energi Indonesia ("SEI") Global Bonds	625,000	625,000	625,000	-
Discount and Issuance Cost - net	(14,327)	(16,430)	(19,074)	(14,656)
Total Subsidiaries	**1,960,673**	**1,958,570**	**1,955,926**	**1,335,344**
Total bonds payable	**12,614,222**	**11,094,096**	**10,385,873**	**9,772,656**

Other information on the Company's bonds payable as of September 30, 2019 is as follows:

	Nominal Issued Amount	Issuance price	Starting date	Maturity date	Trustee	Interest rate
The Company:						
Issued in 2011						
Due in 2021	1,000,000	98.097%	May 23, 2011	May 23, 2021	HSBC Bank USA, N.A	5.25%
Due in 2041	500,000	98.380%	May 27, 2011	May 27, 2041	HSBC Bank USA, N.A	6.50%
Issued in 2012						
Due in 2022	1,250,000	99.414%	May 3, 2012	May 3, 2022	HSBC Bank USA, N.A	4.88%
Due in 2042	1,250,000	98.631%	May 3, 2012	May 3, 2042	HSBC Bank USA, N.A	6.00%
Issued in 2013						
Due in 2023	1,625,000	100.000%	May 20, 2013	May 20, 2023	The Bank of New York Mellon	4.30%
Due in 2043	1,625,000	100.000%	May 20, 2013	May 20, 2043	The Bank of New York Mellon	5.63%
Issued in 2014						
Due in 2044	1,500,000	100.000%	May 30, 2014	May 30, 2044	The Bank of New York Mellon	6.45%
Issued in 2018						
Due in 2048	750,000	98.061%	Nov. 7, 2018	Nov. 7, 2048	The Bank of New York Mellon	6.50%
Issued in 2019						
Due in 2029	750,000	100.000%	July 30, 2019	July 30, 2029	The Bank of New York Mellon	3.65%
Due in 2049	750,000	100.000%	July 30, 2019	July 30, 2049	The Bank of New York Mellon	4.70%
Subsidiary:						
Issued in 2014						
Due in 2024	1,350,000	99.037%	May 12, 2014	May 16, 2024	The Bank of New York Mellon	5.13%
Issued in 2017						
Due in 2024	625,000	100.000%	April 26, 2017	May 5, 2024	Citicorp International Limited	4.45%

21. BONDS PAYABLE (continued)

The Company
The Indenture stipulates that:

- No later than 30 days following the occurrence of an event in which the Government of Indonesia ceases to own, directly or indirectly, more than 50% of the voting securities of the Company (Change of Control Triggering Event), the Company may be required to make an offer to repurchase all senior notes outstanding at a purchase price equal to 101% of their principal amount plus accrued and unpaid interest, if any, to the date of repurchase. The senior notes are subject to redemption in whole, at 100% of their principal amount, together with any accrued interest, at the option of the Company at a certain time in the event of certain changes affecting Indonesian taxation.
- Certain covenants include among others: limitation on liens, limitation on sale and lease back transactions and provision of financial statements and other reports.
- The Company complied with the restrictions specified within the agreements with the Trustee.
- The proceeds from senior notes issued were used to partially fund the capital expenditure requirements in the acquisition of new blocks, development of existing blocks, rig purchase and tanker building.

As of September 30, 2019, the Company was rated as Baa2 with a stable outlook by Moody's Investors Service, BBB with a stable outlook by Fitch Ratings and BBB- with a stable outlook by Standard & Poor's ("S&P").

During the nine-month period ended September 30, 2019, no buy back of portions of senior bonds was made by the Company (for the year ended December 31, 2018: US$37,649).

Subsidiary
- Senior unsecured fixed notes
  In relation to these bonds, the Company is restricted in conducting consolidation, merger, transfer, lease or disposal ofa ll or substantially all of its assets.
  Based on moody's investors services, S&P and Fitch Rating the bonds were rated at Baa3, BB+, and BBB-, respectively.
- SEI senior unsecured fixed rate notes
  SEI is not required to make sinking fund payment with respect of these bonds.
  Based on moody's investors services, S&P and Fitch Rating the bonds were rated at Ba1, BB+, and BB+, respecitvely.

22. EMPLOYEE BENEFITS LIABILITIES

a. Post-employment benefit plans and other long-term employee benefits

The Company and certain Subsidiaries have post-employment benefits plans and provide other long-term employee benefits as follows:

1. Post-employment benefits plans

(i) Defined benefit plan managed by Dana Pensiun Pertamina

The Company and certain Subsidiaries received approval from the MoF of the Republic of Indonesia in Decision Letter No. S-190/MK.6/1977 dated July 15, 1977 to establish a separate pension fund, Dana Pensiun Pertamina, from which all employees, after serving a qualifying period, are entitled to defined benefits upon retirement, disability or death, and also post-employment medical benefits. The Defined Benefit Plans ("PPMP") cover employees who were hired before year 2005.

(ii) Post-retirement healthcare benefits

The post-retirement healthcare benefits involve the Company's retired employees and their spouses that had minimum 15 years of services and minimum 46 years old.

(iii) Severance and service pay ("PAP")

PAP benefits consist of additional benefits for employees to which they are entitled when they enter the pension age and in the event of permanent disability, death, or voluntary resignation.

2. Other long-term employee benefits plan

The Company provides other long-term employee benefits in the form of pre-retirement benefits ("MPPK"), repatriation costs, annual leave, the Mandiri Guna I Insurance Program and service anniversaries, except for the insurance program benefit.

22. EMPLOYEE BENEFITS LIABILITIES (continued)

a. Post-employment benefit plans and other long-term employee benefits (continued)

3. Employees' saving plan

The Company and certain Subsidiaries (collectively referred to as the Participants) operate an Employees' Saving Plan ("TP") in the form of a defined contribution plan, in which the saving will be received by employees at the end of their service period. Until the fiscal year 2015, all contributions made are managed by PT Pertamina Pedeve Indonesia. Effective on October 28, 2016, PT Pertamina Pedeve Indonesia made a decision to restructure and it is no longer in business activities as a venture capital company so that all of available funds are transferred by management to Pension Fund ("DPLK").

b. Provision for employee benefits

The estimated employee benefits obligations of the Company and most of its Subsidiaries as of December 31, 2018, 2017, and 2016, were determined based on the valuation reports of an independent actuary, PT Dayamandiri Dharmakonsilindo, dated January 9, 2019, January 25, 2018, and January 25, 2017, respectively. The estimated employee benefit obligations of the Company and most of its Subsdiaries as of September 30, 2019 were determined by way of extrapolation of the latest actuarial valuation report. The table below presents a summary of the employee benefits obligations reported in the consolidated statements of financial position:

	As of September 30, 2019 (unaudited)	As of December 31,		
		2018	2017	2016
The Company:				
Pension and other post employment benefits:				
- PPMP	148,894	142,585	200,990	142,326
- Post-retirement healthcare benefits	843,805	786,489	924,654	832,487
- PAP	726,706	718,902	900,396	922,194
- Repatriation costs	5,877	5,423	8,480	8,230
Sub-total (Note 22c.i)	1,725,282	1,653,399	2,034,520	1,905,237
Other long-term employee benefits:				
- MPPK	114,302	104,428	129,278	114,778
- Annual leave and service anniversary	13,424	10,035	16,063	12,843
Sub-total (Note 22c.ii)	127,726	114,463	145,341	127,621
Subsidiaries:				
Pension and other post-employment benefits	384,893	315,515	288,369	228,266
Total Consolidated	**2,237,901**	**2,083,377**	**2,468,230**	**2,261,124**
Current portion (Note 19)	(224,388)	(232,994)	(260,010)	(202,392)
Non-current portion	**2,013,513**	**1,850,383**	**2,208,220**	**2,058,732**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets

The following tables summarize the components of net benefit expense recognized in the statement of profit or loss and other comprehensive income and the funded status and amounts recognized in the statement of financial position for the respective plans for the nine-month period ended September 30, 2019, and the years ended December 31, 2018, 2017, and 2016 are as follows:

i. Post-employment benefits obligations

	September 30, 2019 (unaudited)						
	PPMP						
	Present value of post-employment benefits obligations	Fair value of plan assets	Post-employment benefits obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	674,493	(531,908)	142,585	786,489	718,902	5,423	1,653,399
Current service cost (contribution from employee)	979	(24,749)	(23,770)	7,552	28,075	242	12,099
Interest expense (Interest income)	36,743	(21,649)	15,094	49,766	33,813	272	98,945
Sub-total amounts recognized in profit or loss	**37,722**	**(46,398)**	**(8,676)**	**57,318**	**61,888**	**514**	**111,044**
Benefits paid from plan asset	(1,678)	48,076	46,398	-	-	-	46,398
Benefits paid by the Company	67,927	-	67,927	(19,246)	(61,888)	(178)	(13,385)
Contribution to plan by the Company	-	(1,678)	(1,678)	-	-	-	(1,678)
Gain (loss) on foreign currency exchange	14,602	(112,264)	(97,662)	19,244	7,804	118	(70,496)
Ending balance	**793,066**	**(644,172)**	**148,894**	**843,805**	**726,706**	**5,877**	**1,725,282**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefits obligations (continued)

	December 31, 2018						
	PPMP						
	Present value of post-employment benefits obligations	Fair value of plan assets	Post-employment benefits obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	790,740	(589,750)	200,990	924,654	900,396	8,480	2,034,520
Current service cost (contribution from employee)	3,935	(1,057)	2,878	27,061	48,428	405	78,772
Interest expense (Interest income)	55,823	(42,502)	13,321	67,111	50,139	542	131,113
Sub-total amounts recognized in profit or loss	**59,758**	**(43,559)**	**16,199**	**94,172**	**98,567**	**947**	**209,885**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	(67,025)	36,386	(30,639)	(256,537)	(85,986)	(676)	(373,838)
Experience adjustments	2,452	-	2,452	117,720	31,520	(1,715)	149,977
Sub-total Expense (income) recognized in other comprehensive income	**(64,573)**	**36,386**	**(28,187)**	**(138,817)**	**(54,466)**	**(2,391)**	**(223,861)**
Benefits paid from plan asset	(61,562)	61,562	-	-	-	-	-
Benefits paid by the Company	-	-	-	(35,241)	(169,620)	(1,107)	(205,968)
Contribution to plan by the Company	-	(34,218)	(34,218)	-	-	-	(34,218)
Gain (loss) on foreign currency exchange	(49,870)	37,671	(12,199)	(58,279)	(55,975)	(506)	(126,959)
Ending balance	**674,493**	**(531,908)**	**142,585**	**786,489**	**718,902**	**5,423**	**1,653,399**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefits obligations (continued)

	December 31, 2017						
	PPMP						
	Present value of post-employment benefits obligations	Fair value of plan assets	Post-employment benefits obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	735,775	(593,449)	142,326	832,487	922,194	8,230	1,905,237
Current service cost (contribution from employee)	3,569	(1,266)	2,303	16,809	45,431	534	65,077
Interest expense (Interest income)	60,762	(50,168)	10,594	72,036	67,105	654	150,389
Sub-total amounts recognized in profit or loss	**64,331**	**(51,434)**	**12,897**	**88,845**	**112,536**	**1,188**	**215,466**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	80,080	22,798	102,878	166,048	76,914	836	346,676
Experience adjustments	(18,440)	-	(18,440)	(120,215)	(35,473)	(1,111)	(175,239)
Sub-total Expense (income) recognized in other comprehensive income	**61,640**	**22,798**	**84,438**	**45,833**	**41,441**	**(275)**	**171,437**
Benefits paid from plan asset	(64,177)	64,177	-	-	-	-	-
Benefits paid by the Company	-	-	-	(34,417)	(168,325)	(590)	(203,332)
Contribution to plan by the Company	-	(36,763)	(36,763)	-	-	-	(36,763)
Gain (loss) on foreign currency exchange	(6,829)	4,921	(1,908)	(8,094)	(7,450)	(73)	(17,525)
Ending balance	**790,740**	**(589,750)**	**200,990**	**924,654**	**900,396**	**8,480**	**2,034,520**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefits obligations (continued)

	December 31, 2016						
	PPMP						
	Present value of post-employment benefits obligations	Fair value of plan assets	Post-employment benefits obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	702,452	(608,993)	93,459	719,791	902,089	8,824	1,724,163
Current service cost (contribution from employee)	4,230	(1,418)	2,812	11,680	45,288	502	60,282
Interest expense (Interest income)	64,279	(55,627)	8,652	68,355	77,516	745	155,268
Sub-total amounts recognized in profit or loss	**68,509**	**(57,045)**	**11,464**	**80,035**	**122,804**	**1,247**	**215,550**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	15,564	28,927	44,491	(4,004)	39,711	424	80,622
Experience adjustments	(5,470)	-	(5,470)	45,508	(10,510)	(1,953)	27,575
Sub-total Expense (income) recognized in other comprehensive income	**10,094**	**28,927**	**39,021**	**41,504**	**29,201**	**(1,529)**	**108,197**
Benefits paid from plan asset	(63,909)	63,909	-	-	-	-	-
Benefits paid by the Company	-	-	-	(27,171)	(156,042)	(555)	(183,768)
Contribution to plan by the Company	-	(3,667)	(3,667)	-	-	-	(3,667)
Gain (loss) on foreign currency exchange	18,629	(16,580)	2,049	18,328	24,142	243	44,762
Ending balance	**735,775**	**(593,449)**	**142,326**	**832,487**	**922,194**	**8,230**	**1,905,237**

Unfunded Defined Benefit Pension Plan ("PPMP") will be settled or paid by the Company in accordance with applicable regulations.

The actual return on plan assets as of September 30, 2019 and December 2018, 2017, and 2016 amounted to US$21,649, US$6,116, US$27,369 and US$26,700, respectively.

ii. Other long-term employment benefits

	As of September 30, 2019 (unaudited)		
	MPPK	Annual leave and service anniversary	Total
Beginning balance	104,428	10,035	114,463
Current service cost	4,066	3,123	7,189
Interest cost	5,008	390	5,398
Sub-total benefit cost recognized in the profit or loss	**9,074**	**3,513**	**12,587**
Benefits paid by the Company	(1,463)	(340)	(1,803)
Gain on foreign exchange	2,263	216	2,479
Ending balance	**114,302**	**13,424**	**127,726**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

ii. Other long-term employment benefits (continued)

	As of December 31,								
	2018			2017			2016		
	MPPK	Annual leave and service anniver-sary	Total	MPPK	Annual leave and service anniver-sary	Total	MPPK	Annual leave and service anniver-sary	Total
Beginning balance	129,278	16,063	145,341	114,778	12,843	127,621	114,591	13,042	127,633
Current service cost	6,743	3,866	10,609	6,573	7,039	13,612	5,906	5,980	11,886
Past service cost	-	-	-	-	-	-	(304)	(49)	(353)
Interest cost	7,995	802	8,797	8,828	817	9,645	9,699	969	10,668
Actuarial gain (losses)	(18,078)	(3,605)	(21,683)	4,604	864	5,468	2,647	(2,348)	299
Sub-total benefit cost recognized in the profit or loss	**(3,340)**	**1,063**	**(2,277)**	**20,005**	**8,720**	**28,725**	**17,948**	**4,552**	**22,500**
Benefits paid by the Company	(13,453)	(6,138)	(19,591)	(4,367)	(5,353)	(9,720)	(20,850)	(5,106)	(25,956)
(Loss) gain on foreign exchange	(8,057)	(953)	(9,010)	(1,138)	(147)	(1,285)	3,089	355	3,444
Ending balance	**104,428**	**10,035**	**114,463**	**129,278**	**16,063**	**145,341**	**114,778**	**12,843**	**127,621**

d. Actuarial assumptions

Significant actuarial assumptions applied in the calculation of post-employment benefit obligations and other long-term employment benefits for the Company are as follows:

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Discount rate (per annum):				
- Defined benefits plan administered by Dana Pensiun Pertamina	8.41%	8.41%	7.76%	8.61%
- PAP	8.12%	8.12%	6.44%	7,85%
- Post-retirement healthcare benefits	8.77%	8.77%	7.76%	8.78%
- Repatriation cost	8.29%	8.29%	7.26%	8.57%
- MPPK	8.27%	8.27%	7.07%	8.34%
- Annual leave	7.39%	7.39%	6.35%	7.81%
- Services anniversary	8.30%	8.30%	7.07%	8.50%
Gold in Inflation rate (per annum)	8.00%	8.00%	9.00%	9.00%
Salary increases (per annum)	9.50%	9.50%	9.50%	9.50%
Annual medical expense trend (per annum afterwards)	8.00%	8.00%	8.00%	8.00%
Demographic factors:				
- Mortality:	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011
- Disability (TMI 3):	0.75% TMI 3	0.75% TMI 3	0.75% TMI 3	0.75% TMI 3
- Resignation:				
Until 20 years of age (per annum)	1%	1%	1%	1%
21-55 years of age (per annum)	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56
- Pension	100% at normal retirement age	100% at normal retirement age	100% at normal retirement age	100% at normal retirement age
- Normal retirement age (years)	56 years	56 years	56 years	56 years
- Operational costs of the pension plan:	8% of service cost and 2.11% of benefit payments	8% of service cost and 2.11% of benefit payments	8% of service cost and 2.11% of benefit payments	8% of service cost and 3.5% of benefit payments

22. EMPLOYEE BENEFITS LIABILITIES (continued)

d. Actuarial assumptions (continued)

Investment portfolio of plan assets comprises the following:

	September 30, 2019 (unaudited)		December 31, 2018		2017		2016	
	Investment value	%	Investment value	%	Investment value	%	Investment value	%
Equity instruments	165,838	26%	154,253	29%	171,028	29%	190,834	32%
Debt instruments	279,624	44%	218,082	41%	247,694	42%	256,397	43%
Others	192,401	30%	159,573	30%	171,028	29%	146,218	25%
Total	**637,863**	**100%**	**531,908**	**100%**	**589,750**	**100%**	**593,449**	**100%**

The expected return on plan assets is determined by considering the expected returns from the assets based on current investment policy. Expected yields on fixed interest investments are based on gross redemption yields as of the reporting date. Expected returns on equity and investment properties reflect long-term real rates of return experienced in the respective markets.

Expected contributions to post-employment benefit plans for the nine-month period ended September 30, 2019 and the years ended December 31, 2018, 2017, and 2016, were US$33,226, and US$31,166, US$5,371, and US$5,416, respectively.

The qualitative sensitivity analysis for significant assumptions as of September 30, 2019 is as follows (unaudited):

	Effect on 1% increase to defined benefit obligation	Effect on 1% decrease to defined benefit obligation
Discount rate	(203,033)	231,182
Salary rate	46,932	(69,990)
Healthcare cost trend rate	117,652	(95,064)

The average duration years of the Company's defined benefits plan obligation as of September 30, 2019 and December 31, 2018, 2017, and 2016, are as follows:

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
PPMP	15.38	14.35	15.38	15.91
PAP	6.71	5.98	6.71	5.70
Post-retirement healthcare benefits	25.57	17.84	25.57	20.49

The maturity profile of post-employment benefits obligation of the Company as of September 30, 2019 and December 31, 2018, 2017, and 2016, are as follows:

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Within 1 years	278,224	266,405	291,079	262,536
2 - 5 years	863,445	791,955	903,342	855,130
More than 5 years	22,282,480	22,500,076	23,312,066	16,312,066
	23,424,149	**23,558,436**	**24,506,487**	**17,429,732**

Management believes that the estimated liabilities for employee benefits from all of the Group's pension programs, based on the estimated calculation provided by the actuaries, exceed the minimum liability that is required by Labour Law No. 13/2003.

23. PROVISION FOR DECOMMISIONING AND SITE RESTORATION

The movements in the provision for decommissioning and site restoration are as follows:

	As of September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Beginning balance	2,029,735	2,129,337	1,900,093	2,000,069
Addition (deduction) - net	(53,521)	(186,637)	177,746	(182,246)
Accretion expense (Note 38 and 46a)	60,945	87,035	51,498	82,270
Ending balance	**2,037,159**	**2,029,735**	**2,129,337**	**1,900,093**

The addition (deduction) mainly represents the changes in estimate in decommissioning and site restoration which were applied by the Group.

24. NON-CONTROLLING INTERESTS

	As of September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
PT Perusahaan Gas Negara Tbk.	1,711,838	1,397,957	1,382,334	1,368,449
PT Pertamina Internasional Eksplorasi dan Produksi	340,977	333,294	263,376	-
PT Asuransi Tugu Pratama Indonesia Tbk. (previously PT Tugu Pratama Indonesia)	168,822	143,831	108,797	82,232
PT Elnusa Tbk.	143,892	134,790	132,956	127,485
Pertamina International Timor S.A.	1,348	1,447	1,086	605
Total	**2,366,877**	**2,011,319**	**1,888,549**	**1,578,771**

25. SHARE CAPITAL, ADVANCE FOR SHARE ISSUANCE AND ADDITIONAL PAID-IN CAPITAL

a. Share capital and advance for share issuance

In accordance with Notarial Deed No. 20 dated September 17, 2003 of Lenny Janis Ishak, S.H., and the decision of MoF through Decision Letter No. 408/KMK.02/2003 (KMK 408) dated September 16, 2003, the Company's authorized capital amounted to Rp200 trillion, which consists of 200,000,000 ordinary shares with a par value of Rp1,000,000 (full amount) per share of which Rp100 trillion has been issued and paid by the Government of the Republic of Indonesia through the transfer of identified net assets from the former Pertamina Entity, including its Subsidiaries and its Joint Ventures.

Based on MoF's Decision Letter No. 23/KMK.06/2008 dated January 30, 2008, regarding the Determination of the Opening Balance Sheet of PT Pertamina (Persero) as of September 17, 2003, the total amount of the Government's equity ownership in the Company is Rp82.57 trillion. This amount consists of all of the former Pertamina Entity's net assets and net liabilities excluding LNG plants operated by PT Badak Natural Gas Liquefaction and PT Arun Natural Gas Liquefaction, former upstream assets currently operated by PT Pertamina EP, and certain parcels of land and building assets.

The changes in the Company's issued and paid-up share capital from Rp100 trillion to Rp82,57 trillion (equivalent to US$9,809,882) (full amount) were approved at a GMS held on June 15, 2009 and was documented in Notarial Deed No. 11 of Lenny Janis Ishak, S.H. The amendment was documented in Notarial Deed No. 4 dated July 14, 2009 of Lenny Janis Ishak, S.H., and approved by the Minister of Law and Human Rights of the Republic of Indonesia in Decision Letter No. AHU-45429.AH.01.02.Tahun 2009 dated September 14, 2009. The reduction in the Company's issued and paid-up share capital is effective retrospectively as of September 17, 2003.

As of August 1, 2012, there were additional share capital contributions documented in Notarial Deed No. 1 of Lenny Janis Ishak, S.H. in the amount of Rp520.92 billion (equivalent to US$55,019) and based on PP No. 13 Year 2012 regarding the Addition to the Government's Capital Contribution to Share Capital of State Enterprise PT Pertamina (Persero).

25. SHARE CAPITAL, ADVANCE FOR SHARE ISSUANCE AND ADDITIONAL PAID-IN CAPITAL (continued)

a. Share capital and advance for share issuance (continued)

Based on the GMS dated December 14, 2015, the MoSOE approved the capitalization of retained earnings into share capital amounting to Rp50 trillion with 50,000,000 shares (equivalent to US$3,552,146).

Subsequently, advances for share issuance was capitalized as an addition to issued and paid-up share capital through Notarial Deed No. 10 dated January 11, 2016 of Lenny Janis Ishak, S.H.

The additional issued and paid-up share capital was reported to the Minister of Law and Human Rights through Receipt of Notification regarding the Amendment of Articles of Association No. AHU-AH.01.3-0003113 dated January 15, 2016.

The increase in the Company's authorized capital from Rp200 trillion to Rp600 trillion has been approves by MoSOE as the GMS of the Company through Approval letter No. S-217/MBU/04/2018 dated April 11, 2018 and was documented in Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., and approved by the Minister of Law and Human Rights of the Republic of Indonesia in Decision Letter No. AHU-0052766.AH.01.11.Year 2018 dated April 13, 2018 (Note 4a).

As of September 30, 2019, and December 31, 2018, 2017, and 2016, the Company's issued and paid-up share capital were as follows:

Shareholder	Number of issued and paid-up shares (full amount)	Percentage of ownership	Issued and paid up share capital
September 30, 2019 (unaudited)			
The Government of the Republic of Indonesia	171,227,044	100%	16,191,204
December 31, 2018			
The Government of the Republic of Indonesia	171,227,044	100%	16,191,204
December 31, 2017			
The Government of the Republic of Indonesia	133,090,697	100%	13,417,047
December 31, 2016			
The Government of the Republic of Indonesia	133,090,697	100%	13,417,047

b. Additional paid-in capital

The additional paid-in capital as of September 30, 2019 and December 31, 2018, 2017, and 2016 represent the effect of applying of SFAS 38, Business Combination of Entities Under Common Control (Revised 2012), to recognize the difference between the consideration received/transferred and the amount recorded.

26. GOVERNMENT CONTRIBUTED ASSETS PENDING FINAL CLARIFICATION OF STATUS ("BPYBDS")

a. Refuelling apron installation at Sultan Hasanuddin-Makassar Airport and fuel hydrant facilities at Juanda-Surabaya Airport

Based on Memorandum of Operational Acceptances ("MOACs") No. 05/BA/MKS-HND/XII/2011, No. AU/14525/KEU.1227/XII/2011, No. BA084/F100000/2011-S3 and MOACs No. 005/F00000/2012-S0, No. BA.125 Year 2012, No. 0573/B3/KOBU/IV/2012 from the Ministry of Transportation, the Company obtained management and operation rights of Refuelling Apron Installation at Sultan Hasanuddin Airport-Makassar and Fuel Hydrant Facilities at Juanda Airport-Surabaya, resulting in the balance of this account of Rp12,453 million (equivalent to US$1,361) (Note 15) on December 31, 2017.

26. GOVERNMENT CONTRIBUTED ASSETS PENDING FINAL CLARIFICATION OF STATUS (“BPYBDS”) (continued)

b. Natural gas distribution network ("jargas") for households and gas refueling stations ("SPBG") and supporting infrastructure

As of December 31, 2018, the Company and Secretary General of the Directorate of Oil and Gas of the Ministry of Energy and Mineral Resources as the proxy of budget/goods users have signed the Minutes of Handover of Operations Use ("BASTO") of State Property ("BMN") in the form of Distribution Network ("Jargas") Natural Gas for Households Number BA-05/C00000/2018-S0 and Gas Filling Stations ("SPBG") and Infrastructure Supporting Number BA-06/C00000/2018-S0. The value of BMN assets in the form of land and non-land assets with categories of operating and non-operating assets is Rp5.8 trillion (equivalent to US$399,759) (Note 15), currently these assets are managed by PT Pertagas Niaga and PGN.

Based on the results of the discussion of the Ministry of Finance, the Ministry of Energy and Mineral Resources, the Financial and Development Supervisory Agency ("BPKP"), and the Company agreed that BASTO was recorded and treated as BPYBDS and recorded in other asset accounts. Based on the results of the review of BPKP assets of Jargas and SPBG with free and clear status, it will be recommended to carry out the State Capital Participation ("PMN") process, while those that do not have free and clear status will be returned to the ESDM Directorate General of Oil and Gas.

On July 1, 2019, the BPKP issued a Review Report Number LHR-91/D102/2/2019 of the Ministry of Energy and Mineral Resources which would be proposed to become a PMN with the conclusion of total assets of Rp5.8 trillion (US$399,759), worth Rp36 billion (equivalent to US$2,563) (Note 15) cannot be proposed as a PMN so that it is excluded from BPYBDS records at PT Pertamina (Persero), valued at Rp2.1trillion (equivalent to US$145,217) without notes, and the remaining Rp3.4 trillion (equivalent to US$232,525) can be PMN-registered, with a value of Rp133 billion (equivalent to US$9,164) has not been reviewed, and a value of Rp149 billion (equivalent to US$10,344) represents the difference in the value of the results of the review of assets with the value of assets based on BASTO.

As of September 30, 2019, the Company is still conducting studies as a follow up to the results of the BPKP review.

27. RETAINED EARNINGS AND INTERIM DIVIDEND

a. General Meeting of Shareholders (“GMS”)

On May 31, 2016, the Company held a GMS for the fiscal year 2015. Based on the minutes of meeting, the shareholders approved, among other, the utilization of 2015 net income of the Company as follows:
- Distribution of dividends amounting to Rp6.8 trillion (equivalent to US$499,449); (Note 46)
- The remaining amount of US$920,771 were reserved to support operations and corporate development.

Based on the GMS decision to approve the 2015 annual report of PT Pertamina (Persero), there was an additional appropriation of retained earnings for partnership program and community development program amounting to Rp57,480 million (equivalent to US$4,222) and Rp57,480 million (equivalent to US$4,222), respectively.

On March 16, 2017, the Company held a GMS for the fiscal year 2016. Based on the minutes of meeting, the shareholder approved, among others, the utilization of 2016 net income of the Company as follows:
- Distribution of dividends amounting to Rp12.1 trillion (equivalent to US$907,383); (Note 46)
- The remaining amount of US$2,239,660 were reserved to support operations and corporate development.

Based on the GMS decision to approve the 2017 Company Workplan and Budget (“RKAP”) the Company, there was an additional appropriation of retained earnings for patnership program and community development program amounting to Rp250 billion (equivalent to US$18,707).

On January 17, 2018 based on the GMS decision to approve the 2018 RKAP of the Company, there was an additional appropriation of retained earnings for community development program amounting to Rp275 billion (equivalent to US$19,936).

On May 2, 2018, the Company held a GMS for the fiscal year 2017. Based on the minutes of meeting, the shareholders approved, among other things, the utilization of 2017 net income of the Company as follows:
- Distribution of dividends amounting to Rp8.57 trillion (equivalent to US$614,939); (Note 46)
- The remaining amount of US$1,925,256 were reserved to support operations and corporate development.

On January 23, 2019 based on the GMS decision to approve the 2019 RKAP of the Company, there was an additional appropriation of retained earnings for community development program amounting to Rp124.7 billion (equivalent to US$8,921).

27. RETAINED EARNINGS AND INTERIM DIVIDEND (continued)

a. General Meeting of Shareholders ("GMS") (continued)

On May 31, 2019, the Company held a GMS for the fiscal year 2018. Based on the minutes of meeting, the shareholders approved, among other things, the utilization of 2018 net income of the Company is as follows:
- Distribution of dividends amounting to Rp7.95 trillion (equivalent to US$552,659); (Note 46)
- The remaining amount were reserved to support operations and corporate development.

b. Interim dividend

In 2016, the Company paid an interim dividend for 2016 to the Government amounting to Rp500,000 million (equivalent to US$37,120) based on a request from the Minister of State-Owned Enterprises to President Director through Letter No. S-719/MBU/12/2016 dated December 6, 2016.

The interim dividend payments in 2016 have been recognized as advances as of December 31, 2016.

28. DOMESTIC SALES OF CRUDE OIL, NATURAL GAS, GEOTHERMAL ENERGY AND OIL PRODUCTS

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Pertamax, Pertamax turbo, Pertalite gasoline and Pertadex (diesel oil)	8,228,496	8,455,105	11,215,914	9,794,161	2,388,025
ADO	7,751,734	8,143,952	10,713,543	9,388,019	8,557,555
LPG, Petrochemicals, Lubricants and Others	6,227,635	3,232,753	8,201,023	4,313,150	3,618,572
Premium gasoline	3,758,212	3,319,688	4,509,233	5,429,272	11,488,509
Avtur and Avigas	2,517,994	2,916,105	3,955,434	2,990,276	2,356,815
Natural gas	1,948,704	5,031,749	3,196,038	5,461,178	5,607,942
Crude oil	563,324	796,503	917,333	763,281	335,148
Geothermal energy-steam and Electricity	486,473	481,665	645,593	609,610	524,879
IFO/MFO	455,131	455,251	639,575	492,753	450,635
DMO fees - crude oil	401,096	452,943	612,953	400,621	355,699
Kerosene	85,117	94,483	123,894	137,924	144,135
IDO	5,539	8,077	11,978	8,539	13,782
Total	**32,429,455**	**33,388,274**	**44,742,511**	**39,788,784**	**35,841,696**

29. SUBSIDY REIMBURSEMENTS FROM THE GOVERNMENT

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Current year:					
Subsidy reimbursements for 3 kg LPG cylinders (Note 9b)	1,991,199	2,598,590	3,496,603	2,977,967	1,817,647
Subsidy reimbursements for certain fuel (BBM) products (Note 9c)	1,663,358	1,741,731	2,126,796	595,206	753,250
Subsidy reimbursements for kerosene (Note 9)	-	-	16,828	-	-
Sub-total	3,654,557	4,340,321	5,640,227	3,573,173	2,570,897
Corrections from govenrment audit for subsidy reimbursements:					
- BBM year 2018 (Note 9c)	-	(469)	(699)	-	-
- LPG year 2018 (Note 9b)	-	(709)	(1,252)	-	-
- BBM year 2017 (Note 9c)	-	(147)	(147)	-	-
- LPG year 2017 (Note 9b)	-	(5,661)	(5,661)	-	-
- BBM year 2016 (Note 9c)	-	-	-	(605)	-
- LPG year 2016 (Note 9b)	-	-	-	(484)	-
- BBM year 2015 (Note 9c)	-	-	-	-	(1,574)
- LPG year 2015 (Note 9b)	-	-	-	-	(479)
Sub-total	-	(6,986)	(7,759)	(1,089)	(2,053)
Total	**3,654,557**	**4,333,335**	**5,632,468**	**3,572,084**	**2,568,844**

29. SUBSIDY REIMBURSEMENTS FROM THE GOVERNMENT (continued)

Any difference in subsidy reimbursement between the amount recorded in the books and the results of BPK's and other Government body audit is adjusted in the period when the audit report is received.

30. EXPORT OF CRUDE OIL, NATURAL GAS AND OIL PRODUCTS

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Oil products	1,265,391	1,276,978	1,811,257	968,882	624,030
Crude oil	726,778	749,641	1,187,824	659,722	172,939
Natural gas	491,811	641,503	637,872	245,677	171,402
Total	**2,483,980**	**2,668,122**	**3,636,953**	**1,874,281**	**968,371**

31. REVENUES FROM OTHER OPERATING ACTIVITIES

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Upstream support services	143,164	121,930	156,869	155,442	113,780
Shipping services	133,194	111,388	127,010	124,224	186,489
Health and hospital services	64,664	58,212	76,607	85,383	71,427
Natural gas transport services	60,554	121,841	204,140	151,916	167,313
Insurance services	55,008	51,626	84,585	98,870	9,055
Regasification services	35,103	13,763	31,108	19,224	9,229
Office and hospitality services	33,291	27,456	26,155	23,656	3,163
Transport and technical services	14,707	42,968	13,359	8,994	43,024
Air transport services	13,836	14,131	18,756	39,137	45,188
Portfolio management services	7,746	5,032	4,962	9,157	23,310
Human resources provision and development services	997	17,474	4,825	2,026	2,850
Disparity of Selling Price	-	2,117,280	3,102,218	-	-
Other services	35,082	83,303	55,613	22,071	15,683
Total	**597,346**	**2,786,404**	**3,906,207**	**740,100**	**690,511**

32. COST OF GOODS SOLD

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Beginning balance of oil products	(4,218,260)	(3,778,519)	(3,778,519)	(2,990,517)	(3,023,987)
Provision for decline in value of oil products (Note 10)	167,270	92,854	92,854	76,542	225,457
Sub-total	(4,050,990)	(3,685,665)	(3,685,665)	(2,913,975)	(2,798,530)
Production costs:					
- Direct materials	(13,197,369)	(14,972,010)	(20,349,186)	(15,368,304)	(12,946,694)
- Supporting materials	(870,386)	(828,040)	(1,151,033)	(879,291)	(619,075)
- Rent	(498,354)	(385,077)	(286,481)	(717,475)	(721,033)
- Depreciation (Note 13)	(390,593)	(415,587)	(566,412)	(551,911)	(501,823)
- Salaries, wages, and other employee benefits	(263,209)	(364,873)	(452,184)	(503,547)	(418,830)
- Freight and transportation	(110,665)	(87,861)	(124,215)	(112,534)	(27,754)
- Custom and duty	(98,198)	(110,919)	(152,255)	(138,148)	(83,934)
- Utilities, infrastructure and fuel	(78,781)	(348,211)	(484,322)	(441,655)	(373,478)

32. COST OF GOODS SOLD (continued)

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
- Materials and equipment	(51,101)	(56,791)	(84,460)	(98,863)	(118,591)
- Maintenance and repairs	(59,280)	(59,487)	(115,899)	(114,228)	(97,794)
- Business travel	(18,745)	(12,688)	(17,109)	(15,569)	(13,878)
- Professional services	(79,442)	(60,491)	(124,109)	(82,225)	(87,689)
- Others	(116,992)	(43,560)	(99,311)	(71,035)	(65,277)
Sub-total	(15,833,115)	(17,745,595)	(24,006,976)	(19,094,785)	(16,075,850)
Purchases of oil products and others:					
- Imports of other oil products	(5,436,674)	(6,868,315)	(9,230,605)	(7,515,863)	(3,676,290)
- Imports of premium gasoline	(3,680,814)	(3,312,733)	(4,433,062)	(3,811,785)	(3,735,652)
- Domestic purchases of other oil products	(2,529,182)	(1,821,522)	(2,782,989)	(2,340,875)	(2,037,140)
- Imports of ADO	(133,240)	(962,439)	(1,385,810)	(853,533)	(449,225)
- Purchases of geothermal energy	(865,292)	(903,555)	(1,313,799)	(330,505)	(322,251)
Sub-total	(12,645,202)	(13,868,564)	(19,146,265)	(14,852,561)	(10,220,558)
Ending balance of oil products	3,575,137	4,171,539	4,218,260	3,778,519	2,990,517
Provision for decline in value of oil products (Note 10)	(158,809)	(91,348)	(167,270)	(92,854)	(76,542)
Sub-total	3,416,328	4,080,191	4,050,990	3,685,665	2,913,975
Total	**(29,112,979)**	**(31,219,633)**	**(42,787,916)**	**(33,175,656)**	**(26,180,963)**

33. UPSTREAM PRODUCTION AND LIFTING COSTS

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Depreciation, depletion and amortization (Note 14)	(1,482,889)	(1,270,747)	(1,741,040)	(1,578,988)	(1,568,663)
Contracts	(585,352)	(737,927)	(734,342)	(373,194)	(353,161)
Salaries, wages and other employee benefits	(536,394)	(433,064)	(618,458)	(419,526)	(439,160)
Materials	(269,699)	(131,225)	(267,437)	(287,612)	(222,310)
Technical Assistance Contracts ("TAC")	(211,018)	(347,358)	(335,532)	(136,609)	(283,400)
Amortization of investment in oil & gas Block (Note 12a)	(68,872)	(154,773)	(144,472)	(116,441)	(114,476)
Others	(419,288)	(379,802)	(545,235)	(508,837)	(288,830)
Total	**(3,573,512)**	**(3,454,896)**	**(4,386,516)**	**(3,421,207)**	**(3,270,000)**

34. EXPLORATION COSTS

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Seismic, geological and geophysical	(70,391)	(57,232)	(89,680)	(40,000)	(37,826)
Dry hole	(17,901)	(100,060)	(112,476)	(74,744)	(43,256)
Others	(31,778)	(41,063)	(65,524)	(50,612)	(28,114)
Total	**(120,070)**	**(198,355)**	**(267,680)**	**(165,356)**	**(109,196)**

35. EXPENSES FROM OTHER OPERATING ACTIVITIES

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Cost of services	(1,007,440)	(751,821)	(917,123)	(561,688)	(491,304)
Salaries, wages and other employee benefits	(111,671)	(127,902)	(173,585)	(148,022)	(119,522)
Depreciation (Note 13)	(67,896)	(67,031)	(88,405)	(84,636)	(77,454)
Insurance claims	(65,479)	(64,205)	(92,864)	(68,616)	(15,212)
Total	**(1,252,486)**	**(1,010,959)**	**(1,271,977)**	**(862,962)**	**(703,492)**

36. SELLING AND MARKETING EXPENSES

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Depreciation (Note 13)	(277,548)	(239,152)	(328,695)	(362,241)	(313,688)
Salaries, wages, and other employee benefits	(188,786)	(207,675)	(263,020)	(222,447)	(185,476)
Freight and transportation	(182,807)	(232,708)	(453,664)	(519,929)	(419,518)
LPG filling fee	(80,416)	(70,410)	(113,971)	(132,647)	(98,384)
Taxes, retributions and penalties	(75,765)	(52,976)	(89,179)	(46,201)	(48,714)
Maintenance and repairs	(68,303)	(57,176)	(84,776)	(66,757)	(78,172)
Rental	(60,604)	(13,212)	(26,210)	(44,981)	(20,950)
Professional services	(30,115)	(38,240)	(96,851)	(53,660)	(58,428)
Advertising and promotions	(20,419)	(13,911)	(24,151)	(25,102)	(16,292)
Travel	(17,125)	(11,201)	(15,331)	(12,483)	(10,636)
Materials and equipment	(16,791)	(15,389)	(33,441)	(45,992)	(24,930)
Utilities, infrastructure and fuel	(14,270)	(15,689)	(21,092)	(8,339)	(11,359)
Others	(49,251)	(58,860)	(92,450)	(49,423)	(53,019)
Total	**(1,082,200)**	**(1,026,599)**	**(1,642,831)**	**(1,590,202)**	**(1,339,566)**

37. GENERAL AND ADMINISTRATIVE EXPENSES

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Salaries, wages and other employee benefits	(521,695)	(415,264)	(649,669)	(825,414)	(707,655)
Taxes, retributions and penalties	(191,775)	(231,074)	(295,439)	(222,737)	(195,558)
Depreciation, depletion and amortization (Notes 12, 13 and 14)	(94,359)	(72,337)	(107,538)	(109,792)	(112,136)
Rental	(89,550)	(36,940)	(31,177)	(19,906)	(54,914)
Professional services	(46,511)	(41,754)	(41,828)	(113,979)	(137,567)
Materials and equipment	(33,452)	(27,659)	(36,022)	(52,663)	(49,491)
Maintenance and repairs	(33,355)	(18,288)	(24,825)	(38,009)	(34,637)
Business travel	(18,056)	(15,751)	(23,252)	(26,136)	(20,719)
Training, education and recruitment	(12,839)	(20,347)	(29,828)	(22,570)	(20,271)
Others	(87,690)	(84,068)	(90,333)	(167,728)	(176,342)
Total	**(1,129,282)**	**(963,482)**	**(1,329,911)**	**(1,598,934)**	**(1,509,290)**

38. FINANCE INCOME AND COSTS

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Finance income:					
Due from the Government (Note 9a)	173,395	-	-	-	-
Time deposits	150,267	96,994	161,818	162,988	219,679
Current accounts	42,448	27,974	39,958	38,779	30,654
Other investments	34,402	34,690	54,797	25,277	32,266
Other	-	-	-	6,030	54,035
Total	**400,512**	**159,658**	**256,573**	**233,074**	**336,634**
Finance Costs:					
Bonds	(414,943)	(259,953)	(351,914)	(352,622)	(334,214)
Long-term loans	(110,572)	(142,752)	(172,586)	(202,974)	(183,171)
Short-term loans	(81,682)	(25,710)	(56,499)	(8,465)	(13,900)
Accretion expense (Note 23)	(60,945)	(63,677)	(87,035)	(51,498)	(82,270)
Finance leases	(13,543)	(26,563)	(30,309)	(58,323)	(22,162)
Others	(39,512)	(100,704)	(136,895)	(143,829)	(134,801)
Total	**(721,197)**	**(619,359)**	**(835,238)**	**(817,711)**	**(770,518)**

39. OTHER EXPENSES - NET

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Income from contract and material penalties and claims	39,748	83,323	91,101	41,058	91,775
Rental	14,261	23,184	35,325	34,167	13,730
Adjustment of fair value of other investment (Note 11)	(6,045)	40,476	52,843	(15,862)	27,328
Recovery (provision) for impairment of receivables	(40,096)	116,130	108,757	(49,826)	(40,129)
Increase (decrease) in value of investment in oil and gas blocks (Note 12a)	(52,404)	(154,773)	(154,773)	(83,270)	114,290
Reversal (impairment) of fixed assets (Note 13)	(93,456)	-	2,719	(7,364)	(7,151)
Provision for impairment of oil and gas assets (Note 14)	(109,692)	(201,630)	(218,189)	(191,353)	(186,616)
Interest tax income restitution	-	-	-	99,577	-
Tax penalties under payment tax assesment letter (“SKPKB”) and tax billed (“STP”) (Note 40a)	-	-	(36,622)	-	-
Provision for impairment of goodwill (Note 15d)	-	-	-	(6,890)	(136,264)
Provision for tax dispute (Note 40g)	-	-	-	(621,148)	(733,074)
Tax refund	-	-	-	121,676	-
Impairment of advance payment	-	-	-	-	(34,386)
Final income tax asset revaluation (Note 40h)	-	-	-	(129,610)	-
Writte off of oil and gas properties	-	-	-	(68,546)	-
Joint operation (“JO”) operation	-	-	-	-	17,642
Others - net (each below US$5,000)	(86,069)	(16,669)	38,014	46,809	(5,009)
Total	**(333,753)**	**(109,959)**	**(80,825)**	**(830,582)**	**(877,864)**

40. TAXATION

a. Prepaid taxes

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Corporate Income Tax ("CIT")				
The Company:				
Overpayment of CIT:				
- 2019	230,571	-	-	-
- 2017	14,520	14,520	164,266	-
- 2015	-	-	-	329,143
- 2014	-	-	-	458,370
- 2013	-	-	-	122,365
- 2012	-	-	-	9,713
- 2011	-	-	-	5,066
- 2005	-	-	-	82,014
Sub-total	245,091	14,520	164,266	1,006,671
Subsidiaries:				
CIT and dividend	382,315	434,117	330,676	371,965
Sub-total CIT - Consolidated	**627,406**	**448,637**	**494,942**	**1,378,636**
VAT				
The Company:				
- 2018	297,904	386,989	-	-
- 2017	-	-	418,255	-
- 2016	15,565	84,290	-	-
- 2012	-	-	-	82,353
- 2009	-	-	-	18,750
- 2007	-	-	-	124,624
Sub-total	313,469	471,279	418,255	225,727
Subsidiaries:				
VAT reimbursable	313,679	315,238	313,468	404,523
VAT	381,482	386,737	396,890	214,618
Sub-total	695,161	701,975	710,358	619,141
Sub-total VAT - Consolidated	**1,008,630**	**1,173,254**	**1,128,613**	**844,868**
Other taxes	**18,994**	**18,994**	**-**	**127,080**
Total prepaid tax	**1,655,030**	**1,640,885**	**1,623,555**	**2,350,584**
Provision	-	-	-	(313,196)
Total	**1,655,030**	**1,640,885**	**1,623,555**	**2,037,388**
Current portion	(672,034)	(820,598)	(794,255)	(567,621)
Non-current portion	**982,996**	**820,287**	**829,300**	**1,469,767**

40. TAXATION (continued)

a. Prepaid taxes (continued)

Details of VAT reimbursable are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
VAT reimbursable by SKK Migas:				
- PGN and its subsidiaries	72,642	69,014	75,356	92,585
- PT Pertamina EP	66,075	84,264	73,348	130,604
- PT Pertamina EP Cepu	50,493	31,194	43,160	55,253
- PHE and its subsidiaries	15,545	28,009	26,638	40,817
Sub-total	204,755	212,481	218,502	319,259
VAT reimbursable by the Directorate General of Budgeting and Finance Stability:				
PT Pertamina Geothermal Energy	108,924	102,757	94,966	85,264
Total	**313,679**	**315,238**	**313,468**	**404,523**

On September 3 and 5, 2019, the Company obtained from Directorate General of Taxes ("DGT") decisions No. KEP-01403/KEB/WPJ.19/2019 until KEP-01417/KEB/WPJ.19/2019 and KEP-01419/KEB/WPJ.19/2019 regarding tax underpayment assessment on witholding income tax and VAT for fiscal year 2016 amounted Rp276,602 million (equivalent to US$19,461) and Rp235,652 million (equivalent to US$16,575), respectively. As of September 30, 2019 the amount was still recorded as prepaid tax due to payment process was not executed yet.

On April 9, 2019, the Company obtained from DGT decision number KEP-00297/NKEB/WPJ.19/2019 regarding the sanctions write-off STP VAT for fiscal year 2016 amounted Rp400,929 million (equivalent to US$28,147). The amount has been net off for VAT Payable in period of June 2019.

On March 21, 2019, the Company obtained from DGT decisions No. KEP-00244/NKEB/WPJ.19/2019 until KEP-00255/NKEB/WPJ.19/2019 regarding the write-off STP VAT for fiscal year 2016 amounted Rp590,934 million (equivalent to US$40,578). The amount has been received by the Company during April 2019.

On December 27, 2018, the Company received SKPKB and STP for fiscal year 2016 amounting to Rp3,234 billion (equivalent to US$222,250). The SKPKB consists of SKPKB of CIT amounting to Rp565,949 million (equivalent to US$39,031), SKPKB of withholding income tax amounting to Rp1,381 billion (equivalent to US$94,851) and SKPKB of VAT amounting to Rp295,043 million (equivalent to US$20,260). STP consists of tax bills on VAT and penalties amounting to Rp590,934 million (equivalent to US$40,578) and Rp400,929 million (equivalent to US$27,530), respectively.

From the overall value of the SKPKB and STP, the Company charged Rp533,324 million (equivalent to US$36,622) in the 2018 income statement (Note 39), Rp1.504 billion (equivalent to US$103,283) was recorded as prepaid tax, and Rp565,949 million (equivalent to US$39,031) was recorded as prior year adjustment of CIT, while the remaining value of amounting to Rp630,776 million (equivalent to US$43,315) has not been paid. The Company has filed an objection on January 25, 2019, for the SKPKB PPh 22, PPh 23, PPh 4 (2), PPh 15, SKPKB and STP of VAT.

On November 7, 2018, the Company received a letter of tax refund for overpayment of CIT fiscal year 2017 from DGT of Big Three Taxpayers office No.80367/051-00367-2018 for tax refund amounting to Rp2,264 billion by calculating taxes payable compensation amounting to Rp159 million, so it was paid amounting to Rp2,264 billion (equivalent to US$154,758).

On February 9, 2018, the Company obtained decision No. Kep-29/WPJ.19/2018 from DGT regarding the Determination of Certain Taxpayers with Specific Criteria, effective from January 1, 2018 to December 31, 2019. Taxpayers that fulfilled all criterias can be get any tax refund if they had previously overpaid taxes.

On March 21, 2017, the Tax Court partially accepted the Company's tax appeals on SKPKB of VAT for period December 2007. The Company received tax refund for the overpayment of VAT amounting to Rp1,621 billion (equivalent to US$121,576) on August 3, 2017.

40. TAXATION (continued)

a. Prepaid taxes (continued)

The increase in VAT payments in 2017 was mainly due to advance payment of VAT for LPG and diesel subsidies, and withholding income tax.

On March 3, 2017, the Company received tax refund overpayment letters for overpayment of CIT fiscal years 2014 and 2013, respectively amounting to Rp3,884 billion (equivalent to US$296,363) and Rp23,253 million (equivalent to US$1,754).

On December 31, 2015, through letter No.860/H00000/2015-S4, the Company submitted a request for revaluation of fixed assets for tax purposes submitted in 2015 to the Regional Office of DGT Large Taxpayers and has paid the Final Income Tax amounting to Rp1,300 billion (equivalent to US$95,182).

On December 7, 2016, through letter No. 751/H00000/2016-S4, the Company notified DGT that the submission of the tax requirements for revaluation will be deferred to 2017. As a consequence, the Company made additional final income tax payment in December 2016 on the revaluation amounting to Rp429,771 million (equivalent to US$31,899).

The payment of final income tax amounting to Rp1,300 billion (equivalent to US$95,182) and the additional payment of final income tax on revaluation amounting to Rp429,771 million (equivalent to US$31,899) are presented under prepaid taxes - current portion in the 2016 consolidated statement of financial position.

b. Taxes payable

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
CIT - Company	21,358	19,684	-	214,988
CIT - Subsidiaries	476,781	447,921	308,803	260,588
Sub-total	498,139	467,605	308,803	475,576
Other taxes:				
- Income taxes - Article 21	23,916	33,909	39,763	41,982
- Income taxes - Article 22	13,085	10,580	6,341	7,907
- Income taxes - Article 23/26	11,322	13,189	11,363	30,196
- Income taxes - Article 15/4(2)	11,227	6,271	7,101	5,477
- Income taxes - Article 24	5	269	1	5
- VAT	77,528	74,542	68,617	58,001
- Fuel taxes	119,400	119,645	117,347	107,985
Sub-total	256,483	258,405	250,533	251,553
Total	**754,622**	**726,010**	**559,336**	**727,129**

c. Income tax expense - net

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Current tax expense (Note 40d)	(1,472,159)	(1,790,708)	(2,627,443)	(1,699,088)	(2,046,133)
Deferred income tax benefit (expense) (Note 40e)	(201,986)	(251,974)	(385,759)	532,264	168,484
Net	**(1,674,145)**	**(2,042,682)**	**(3,013,202)**	**(1,166,824)**	**(1,877,649)**

40. TAXATION (continued)

d. Current taxes

Current income tax computation is based on estimated taxable income/(loss). The amounts may be adjusted when annual tax returns are filed with the DGT.

The reconciliation between the consolidated profit before income tax and estimated taxable income is as follows:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Consolidated profit before income tax expense	2,450,034	4,731,898	5,729,596	3,867,228	5,348,883
Add:					
Consolidation eliminations	2,459,305	2,655,069	3,610,474	2,247,936	1,950,464
Profit before income tax - Subsidiaries	(4,086,985)	(4,846,015)	(6,610,027)	(3,821,301)	(3,021,213)
Profit before income tax - the Company	822,354	2,540,952	2,730,043	2,293,863	4,278,134
Temporary differences:					
Provision for incentives and performance bonuses (tantiem)	(140,949)	(46,151)	(6,894)	19,920	82,587
Provision for impairment of financial assets	13,581	(153,312)	(139,273)	20,305	59,249
Finance lease assets and liabilities	13,725	(20,770)	(7,368)	48,659	11,318
Discount and unamortized debt issuance cost	4,334	2,671	(55)	8,095	6,929
Provision for impairment of non-free and non-clear assets	-	-	-	-	2,589
Accrual for legal costs	295	14,509	14,918	8,087	2,044
Provision for impairment of inventories	8,207	14,406	137,248	32,404	(181,202)
Fixed assets depreciation	(83,554)	(79,392)	(112,976)	(2,756)	(44,036)
Receivable fair value adjustment from differences in pricing (Notes 2u and 9a)	(173,395)	668,524	981,331	-	-
Employee benefits liability	27,830	(272,853)	(181,421)	(121,652)	(18,346)
Fixed asset revaluation	-	-	(14,221)	-	-
Others	(6,174)	(261)	7,624	(346)	(346)

40. TAXATION (continued)

d. Current taxes (continued)

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Permanent differences:					
Non-deductible expenses	394,871	201,454	342,456	1,093,884	1,273,304
Post-retirement healthcare benefits	57,316	(142,709)	648	46,334	71,192
Non-depreciable fixed assets	3,859	2,624	5,372	5,201	1,604
Income from subsidiaries and associates	(2,354,580)	(2,373,340)	(3,341,620)	(1,997,866)	(1,557,363)
Interest income subjected to final tax	(326,130)	(88,611)	(149,244)	(148,704)	(213,821)
Other income subjected to final tax	(2,390)	(7,257)	1,055,818	(147,399)	(12,565)
Total temporary and permanent differences	(2,563,154)	(2,280,468)	(1,407,657)	(1,135,834)	(516,863)
Taxable income (loss) - the Company	**(1,740,800)**	**260,484**	**1,322,386**	**1,158,029**	**3,761,271**
Current income tax - the Company	-	65,121	330,597	289,507	940,318
Under provision of 2005 corporate income tax - the Company	-	3,372	42,403	-	-
Current income tax - Subsidiaries	1,472,159	1,722,215	2,254,443	1,409,581	1,105,815
Consolidated current income tax	**1,472,159**	**1,790,708**	**2,627,443**	**1,699,088**	**2,046,133**

The reconciliation between the Group's income tax expense and the theoretical tax amount on the Group's consolidated profit before income tax is as follows:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Profit before income tax - Consolidated	2,450,034	4,731,898	5,729,596	3,867,228	5,348,883
Tax calculated at weighted average statutory tax rates	1,434,363	1,995,146	2,301,890	1,828,634	2,034,422
Non-deductible expenses	301,989	262,966	375,007	492,336	428,749
Post-retirement healthcare benefits	14,329	(35,677)	162	11,583	17,798
Non-depreciable fixed assets	1,016	675	1,368	(8,856)	429
Income from subsidiaries and associates	(603,455)	(648,913)	(868,954)	(553,989)	(430,719)
Income subjected to final tax	194,083	486,635	1,198,784	(35,280)	(129,449)
Interest income subjected to final tax	(103,380)	(21,522)	(37,458)	(34,943)	(43,581)
Fixed assets revaluation	-	-	-	(532,661)	-
Prior year adjustments	-	3,372	42,403	-	-
Unrecognized tax loss	435,200	-	-	-	-
Consolidated corporate income tax expense	**1,674,145**	**2,042,682**	**3,013,202**	**1,166,824**	**1,877,649**

The theoretical amount of income tax expense is calculated using the weighted average tax rate applicable to entities consolidated to the Group. The weighted average tax rate were 68%, 43%, 53%, 30% and 35% for the nine-month periods ended September 30, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016, respectively.

40. TAXATION (continued)

e. Deferred tax

	September 30, 2019 (unaudited)						
	January 1, 2019	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	September 30, 2019
Deferred tax assets							
Employee benefits	247,522	-	24	4,033	331	7,603	259,513
Provision for impairment of financial assets	79,477	-	-	77	-	3,165	82,719
Provision for decommissioning and site restoration	122,236	-	18	-	-	(17,008)	105,246
Provision for incentives and performance bonuses (tantiem)	62,096	-	-	15	-	(35,483)	26,628
Unrealized profits from transaction at consolidation level	75,694	-	-	-	-	(10,864)	64,830
Fixed assets	586,578	-	-	23,051	-	(10,452)	599,177
Provision for impairment of inventories	70,367	-	-	12	-	973	71,352
Provision for impairment of non-free and non-clear assets	27,589	-	-	-	-	-	27,589
Tax losses carry-forward	2,071	-	(449)	34	-	(1,380)	276
Deferred revenues	276	-	-	-	-	5	281
Accrual for legal cost	7,369	-	-	-	-	74	7,443
Oil and gas properties	(72,763)	-	-	-	-	3,700	(69,063)
Finance lease assets and liabilities	(12,996)	-	-	-	-	3,522	(9,474)
Discount and unamortized debt issuance cost	(5,951)	-	-	-	-	1,084	(4,867)
Receivable fair value adjustment from Disparity of Selling Price (Notes 2u and 9a)	245,333	-	-	-	-	(43,349)	201,984
Others	6,968	-	717	(6,055)	-	(395)	1,235
Sub-total consolidated deferred tax assets - net	**1,441,866**	**-**	**310**	**21,167**	**331**	**(98,805)**	**1,364,869**
Deferred tax liabilities							
Provision for decommissioning and site restoration	365,066	-	-	-	-	(25,221)	339,845
Finance lease assets	29,905	-	-	-	-	5,379	35,284
Deferred revenues	8,068	-	-	-	-	2,395	10,463
Employee benefits	16,657	-	-	-	-	3,657	20,314
Provision for impairment	2,008	-	-	-	-	2,498	4,506
Oil and gas properties	(3,070,616)	-	-	-	-	(47,754)	(3,118,370)
Excess of fair value over net book value	(12,598)	-	-	-	-	528	(12,070)
Fixed assets	(201,891)	-	-	(73)	-	(7,600)	(209,564)
Unrealized profits from transaction at consolidation level	(342,856)	-	-	-	-	23,769	(319,087)
Others	(101,149)	-	-	294	-	(60,832)	(161,687)
Sub-total consolidated deferred tax liabilities - net	**(3,307,406)**	**-**	**-**	**221**	**-**	**(103,181)**	**(3,410,366)**
Total	**(1,865,540)**	**-**	**310**	**21,388**	**331**	**(201,986)**	**(2,045,497)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2018						
	January 1, 2018	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2018
Deferred tax assets							
Employee benefits	314,471	-	516	5,143	(1,302)	(71,306)	247,522
Provision for impairment of financial assets	121,406	-	-	(367)	-	(41,562)	79,477
Provision for decommissioning and site restoration	136,394	-	591	-	-	(14,749)	122,236
Provision for incentives and performance bonuses (tantiem)	83,513	-	-	(43)	-	(21,374)	62,096
Unrealized profits from transaction at consolidation level	64,825	-	-	-	-	10,869	75,694
Fixed assets	518,336	-	-	(3,486)	133	71,595	586,578
Provision for impairment of inventories	37,156	-	-	(46)	-	33,257	70,367
Provision for impairment of non-free and non-clear assets	27,588	-	-	1	-	-	27,589
Tax losses carry-forward	13,764	-	1,567	(27)	-	(13,233)	2,071
Deferred revenues	7,590	-	-	-	-	(7,314)	276
Accrual for legal cost	3,640	-	-	-	-	3,729	7,369
Oil and gas properties	(5,002)	-	(3,382)	-	-	(64,379)	(72,763)
Finance lease assets and liabilities	(11,205)	-	-	2	-	(1,793)	(12,996)
Discount and unamortized debt issuance cost	(5,937)	-	-	-	-	(14)	(5,951)
Receivable fair value adjustment from Disparity of Selling Price (Notes 2u and 9a)	-	-	-	-	-	245,333	245,333
Others	64,541	-	(2,439)	(298)	-	(54,836)	6,968
Sub-total consolidated deferred tax assets - net	**1,371,080**	**-**	**(3,147)**	**879**	**(1,169)**	**74,223**	**1,441,866**
Deferred tax liabilities							
Provision for decommissioning and site restoration	371,738	-	-	-	-	(6,672)	365,066
Finance lease assets	29,013	-	-	-	-	892	29,905
Deferred revenues	10,750	-	-	-	-	(2,682)	8,068
Employee benefits	8,549	-	-	-	(395)	8,503	16,657
Provision for impairment	1,081	-	-	-	-	927	2,008
Oil and gas properties	(2,801,228)	-	-	-	-	(269,388)	(3,070,616)
Excess of fair value over net book value	(14,114)	-	-	-	-	1,516	(12,598)
Fixed assets	(351,100)	-	-	174	-	149,035	(201,891)
Unrealized profits from transaction at consolidation level	(377,158)	-	-	-	-	34,302	(342,856)
Others	274,317	-	-	949	-	(376,415)	(101,149)
Sub-total consolidated deferred tax liabilities - net	**(2,848,152)**	**-**	**-**	**1,123**	**(395)**	**(459,982)**	**(3,307,406)**
Total	**(1,477,072)**	**-**	**(3,147)**	**2,002**	**(1,564)**	**(385,759)**	**(1,865,540)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2017						
	January 1, 2017	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2017
Deferred tax assets							
Employee benefits	302,651	-	321	3,365	40,486	(32,352)	314,471
Provision for impairment of financial assets	114,611	-	864	(98)	-	6,029	121,406
Provision for decommissioning and site restoration	123,449	-	-	-	-	12,945	136,394
Provision for incentives and performance bonuses (tantiem)	72,084	-	-	102	-	11,327	83,513
Unrealized profits from transaction at consolidation level	48,756	-	-	-	-	16,069	64,825
Fixed assets	(24,717)	-	2,612	(17)	-	540,458	518,336
Provision for impairment of inventories	29,194	-	-	(8)	-	7,970	37,156
Provision for impairment of non-free and non-clear assets	27,588	-	-	-	-	-	27,588
Tax losses carry-forward	41,240	-	-	-	-	(27,476)	13,764
Deferred revenues	12,100	-	-	140	-	(4,650)	7,590
Accrual for legal cost	1,618	-	-	-	-	2,022	3,640
Oil and gas properties	(37,375)	-	-	-	-	32,373	(5,002)
Finance lease assets and liabilities	(23,333)	-	-	(1)	-	12,129	(11,205)
Discount and unamortized debt issuance cost	(7,962)	-	-	-	-	2,025	(5,937)
Others	71,559	-	666	(36)	-	(7,648)	64,541
Sub-total consolidated deferred tax assets - net	**751,463**	**-**	**4,463**	**3,447**	**40,486**	**571,221**	**1,371,080**
Deferred tax liabilities							
Provision for decommissioning and site restoration	367,350	(1,058)	-	-	-	5,446	371,738
Finance lease assets	30,670	-	-	-	-	(1,657)	29,013
Deferred revenues	22,404	-	-	-	-	(11,654)	10,750
Employee benefits	7,353	-	-	-	180	1,016	8,549
Provision for impairment	1,085	696	-	-	-	(700)	1,081
Oil and gas properties	(2,437,710)	(276,196)	-	-	-	(87,322)	(2,801,228)
Excess of fair value over net book value	(30,845)	2,352	-	-	-	14,379	(14,114)
Fixed assets	(242,785)	(8,362)	-	575	-	(100,528)	(351,100)
Unrealized profits from transaction at consolidation level	(410,531)	-	-	-	-	33,373	(377,158)
Others	164,492	48	-	1,087	-	108,690	274,317
Sub-total consolidated deferred tax liabilities - net	**(2,528,517)**	**(282,520)**	**-**	**1,662**	**180**	**(38,957)**	**(2,848,152)**
Total	**(1,777,054)**	**(282,520)**	**4,463**	**5,109**	**40,666**	**532,264**	**(1,477,072)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2016						
	January 1, 2016	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2016
Deferred tax assets							
Employee benefits	289,390	-	(4,208)	2,331	16,029	(891)	302,651
Provision for impairment of financial assets	99,317	-	(115)	97	-	15,312	114,611
Provision for decommissioning and site restoration	74,989	-	-	-	-	48,460	123,449
Provision for incentives and performance bonuses (tantiem)	51,630	-	-	(1,680)	-	22,134	72,084
Unrealized profits from transaction at consolidation level	37,732	-	-	-	-	11,024	48,756
Fixed assets	883	-	(1,124)	52	-	(24,528)	(24,717)
Provision for impairment of inventories	72,099	-	-	17	-	(42,922)	29,194
Provision for impairment of non-free and non-clear assets	26,941	-	-	-	-	647	27,588
Tax losses carry-forward	43,114	-	-	-	-	(1,874)	41,240
Deferred revenues	11,456	-	(1,033)	-	-	1,677	12,100
Accrual for legal cost	1,107	-	-	-	-	511	1,618
Oil and gas properties	(39,211)	-	-	-	-	1,836	(37,375)
Finance lease assets and liabilities	(26,204)	-	-	-	-	2,871	(23,333)
Discount and unamortized debt issuance cost	(9,717)	-	-	-	-	1,755	(7,962)
Others	72,066	-	543	51	-	(1,101)	71,559
Sub-total consolidated deferred tax assets - net	**705,592**	**-**	**(5,937)**	**868**	**16,029**	**34,911**	**751,463**
Deferred tax liabilities							
Provision for decommissioning and site restoration	349,814	-	-	-	-	17,536	367,350
Finance lease assets	27,751	-	-	-	-	2,919	30,670
Deferred revenues	29,449	-	-	-	-	(7,045)	22,404
Employee benefits	10,724	-	-	-	(839)	(2,532)	7,353
Provision for impairment	5,888	-	-	-	-	(4,803)	1,085
Oil and gas properties	(2,544,971)	-	-	-	-	107,261	(2,437,710)
Excess of fair value over net book value	(33,130)	-	-	-	-	2,285	(30,845)
Fixed assets	(226,707)	-	-	-	-	(16,078)	(242,785)
Unrealized profits from transaction at consolidation level	(429,915)	-	-	-	-	19,384	(410,531)
Others	162,407	(10,396)	-	(2,165)	-	14,646	164,492
Sub-total consolidated deferred tax liabilities - net	**(2,648,690)**	**(10,396)**	**-**	**(2,165)**	**(839)**	**133,573**	**(2,528,517)**
Total	**(1,943,098)**	**(10,396)**	**(5,937)**	**(1,297)**	**15,190**	**168,484**	**(1,777,054)**

Deferred tax assets and liabilities as of September 30, 2019, and December 31, 2018, 2017, and 2016 have been calculated taking into account the applicable tax rates for each respective period.

The Group's management is of the opinion that the above deferred tax assets can be fully recovered through future taxable income.

40. TAXATION (continued)

f. Administration

The Indonesian prevailing Tax Law requires each Company in the Group to submit individual tax returns on the basis of self assessment. Under the prevailing regulations, DGT may assess or amend tax within certain periods. For the fiscal year of 2007 and backward, this amendment period is within ten years from the time the tax due, but not later than 2013, while for the fiscal year of 2008 and onwards, the period is within five years from the time the tax due.

g. Tax amnesty

The Company participated in Tax Amnesty Program on March 31, 2017 and received the certificate of Tax Amnesty No. KET-369/PP/WPJ.19/2017 on April 6, 2017. As a result the Company withdrew, by law, all processes of Objections, Appeals, and Judicial reviews for the fiscal year until 2015.

The results of the tax amnesty program are as follows:
a. The Company's remaining amount of 2014 fiscal loss amounting to US$75,362 will not be compensated.
b. Tax dispute which was previously recognized in prepaid tax non-current portion amounting to US$621,148 (net of provision which has been recorded) (Note 39), were expensed.

PT Pertamina Lubricants participated in Tax Amnesty Program on March 31, 2017 and received the certificate of Tax Amnesty on April 5, 2017. As a result, PT Pertamina Lubricants withdrew, by law, all processes of Objections, Appeals, and Judicial reviews for the fiscal year until 2015.

As consequences of the tax amnesty program discussed above, PT Pertamina Lubricants has written-off its input VAT amounting to Rp210,301 million (equivalent to US$15,418).

h. Fixed asset revaluation for tax purposes

The Company submitted a request to revalue certain refineries assets for tax purposes on December 28, 2016.

On July 10, 2017, the Company received approval for the revaluation of refineries as referred to the decision of the Director General of Taxes No. KEP-104/WPJ.19/2017. The consequences of the approval are as follows:
a. Prepaid tax of final income tax amounting to US$129,610 was recognized as expense (Note 39).
b. Recognized deferred tax assets amounting to US$532,660.

41. RELATED PARTY BALANCES AND TRANSACTIONS

Significant related party accounts are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Cash and cash equivalents (Note 6)	7,435,046	8,416,251	6,065,489	6,465,644
Restricted cash (Note 7)	172,272	86,230	88,896	114,855
Trade receivables - related parties (Note 41a)	1,711,453	1,297,651	1,095,016	1,422,268
Due from the Government (Note 9)	5,280,429	4,758,409	2,155,739	1,792,457
Other receivables - related parites (Note 41b)	217,950	149,178	255,054	242,839
Restricted cash - non-current (Note 15a)	1,052,754	910,999	846,363	662,751
Advance dividend payment (Note 27b)	-	-	-	37,120
Total	**15,869,904**	**15,618,718**	**10,506,557**	**10,737,934**
As a percentage of total assets	**25%**	**24%**	**18%**	**20%**
Short-term loans (Note 16)	1,370,058	3,164,724	355,518	47,509
Trade payables - related parties (Note 41c)	157,011	78,781	49,277	118,540
Due to the Government (Note 18)	2,339,357	2,002,825	1,831,245	1,685,118
Long-term liabilities (Note 20)	181,775	179,361	174,638	211,074
Other payables - related parties (Note 41d)	32,461	54,011	56,625	50,947
Total	**4,080,662**	**5,479,702**	**2,467,303**	**2,113,188**
As a percentage of total liabilities	**12%**	**16%**	**8%**	**7%**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

a. Trade receivables

Trade receivables - related parties result from domestic sales of crude oil, natural gas and geothermal energy and the export of oil products.

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables - related parties	1,765,039	1,330,381	1,141,863	1,528,092
Provision for impairment	(53,586)	(32,730)	(46,847)	(105,824)
Net	**1,711,453**	**1,297,651**	**1,095,016**	**1,422,268**

Trade receivables based on customers are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Indonesian Armed Forces ("TNI")/ Ministry of Defence (Note 48b.ii)	432,010	318,142	258,566	644,950
PT Garuda Indonesia (Persero) Tbk.	401,833	226,166	106,801	93,939
PLN and its subsidiaries	345,691	381,559	385,419	493,043
PT Patra SK	40,001	40,013	40,117	35,754
PT Pupuk Indonesia (Persero)	21,185	25,412	43,667	33,105
Polisi Republik Indonesia ("Polri")	29,947	508	-	253
PT Merpati Nusantara Airlines (Persero)	11,736	11,499	12,254	12,352
PT Aneka Tambang	5,642	14,226	-	-
PT Pembangkitan Jawa-Bali	-	17,484	1,069	5,302
PPT Energy Trading Co., Ltd.	-	22	47,275	-
PT Donggi Senoro LNG	226	28,828	14,789	12,031
Others	476,768	266,522	231,906	197,363
	1,765,039	1,330,381	1,141,863	1,528,092
Provision for impairment	(53,586)	(32,730)	(46,847)	(105,824)
Total	**1,711,453**	**1,297,651**	**1,095,016**	**1,422,268**

Movements in the provision for impairment of trade receivables from related parties are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(32,730)	(46,847)	(105,824)	(47,550)
Reversal of provision for impairment for recovered receivables - net	47	18,734	92,757	14,006
Impairment during the period/year	(20,388)	(7,606)	(32,854)	(73,604)
Foreign exchange	(515)	2,989	(926)	1,324
Ending balance	**(53,586)**	**(32,730)**	**(46,847)**	**(105,824)**

Management believes that the provision for impairment is adequate to cover possible losses that may arise from the uncollectible trade receivables from related parties.

Details of trade receivables by currencies are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Indonesian rupiah	1,357,236	870,672	610,347	1,080,200
US dollar	407,733	459,641	531,449	447,828
Others	70	68	67	64
Total	**1,765,039**	**1,330,381**	**1,141,863**	**1,528,092**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

a. Trade receivables (continued)

Receivable from fuel and lubricant distribution to the Indonesian Armed Forces/Ministry of Defence

The fuel and lubricant distribution to the Indonesian Armed Forces/Ministry of Defence is based on the planned needs of the Indonesian Armed Forces/Ministry of Defence and is capped by the State Budget for Fuels and Lubricants ("BMP") as one of the expenditure items of the Indonesian Armed Forces/Ministry of Defence, the details are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	318,142	258,566	644,950	487,515
Distribution of fuel and lubricant	328,473	479,959	383,307	344,097
Collections from BMP distribution	(221,147)	(403,723)	(764,355)	(199,693)
Foreign exchange	6,542	(16,660)	(5,336)	13,031
Net	**432,010**	**318,142**	**258,566**	**644,950**

At September 30, 2019, and December 31, 2018, 2017, and 2016, management has recognized impairment the amounting to US$33,396, and US$12,992, US$10,409 and US$85,136, respectively.

Receivable from fuel distribution to PLN

The Company distributes diesel fuel and industrial fuel oil to PLN for their power plant in all regions across Indonesia. In 2019, the Company has made collections from PLN based on the price agreed by the Boards of Directors of the Company and PLN on May 22, 2018.

Should there be difference between the provisional and the final agreed formulation prices, the adjustment will be recorded in the period when the final formulation prices agreement is completed.

b. Other receivables

Other receivables by customers are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
PT Donggi Senoro LNG	119,764	115,500	109,458	105,286
PT Jawa Satu Power	-	-	96,000	-
PT Perta Daya Gas	-	-	34,152	-
PT Merpati Nusantara Airlines (Persero)	18,569	18,190	19,472	19,550
Others (each below US$10,000)	137,365	100,011	97,181	225,218
Sub-total	275,698	233,701	356,263	350,054
Provision for impairment	(20,009)	(19,616)	(20,860)	(20,983)
Sub-total	255,689	214,085	335,403	329,071
Less: current portion	**(217,950)**	**(149,178)**	**(255,054)**	**(242,839)**
Non-current portion (Note 15)	**37,739**	**64,907**	**80,349**	**86,232**

Movements in the provision for impairment of other receivables from related parties are as follows:

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	(19,616)	(20,860)	(20,983)	(20,491)
Reversal of impairment on the recovered receivables	(566)	699	127	1
Impairment during the period/year	-	(705)	(162)	(1)
Foreign exchange difference	173	1,250	158	(492)
Ending balance	**(20,009)**	**(19,616)**	**(20,860)**	**(20,983)**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

b. Other receivables (continued)

Management believes that the provision for impairment is adequate to cover possible losses that may arise from the uncollectible other receivables from related parties.

Receivables from PT Donggi Senoro LNG

The receivables from PT Donggi Senoro LNG as of September 30, 2019 and December 31, 2018, 2017, and 2016 amounted to US$119,764 and US$115,500, US$109,458 and US$105,286 are intended for the construction of a LNG production facility with a capacity of 2 million tonnes per year. PT Donggi Senoro LNG is owned by PHE (29%), Sulawesi LNG Development Limited (59.9%) and PT Medco LNG Indonesia (11.1%). This project, which was planned to be finalised in 4 years, is funded by 40% from equity and 60% from loan.

The interest rate on the loan is one month US dollar LIBOR plus 3.75% per annum and interest is due every three months after the loan drawdowns. In 2018 and 2017, accrued interest was added to the loan since the LNG production facility is still under construction. Interest income for the nine-month period ended September 30, 2019, and for the years ended December 31, 2018, 2017, and 2016 are US$5,016, and US$7,110, US$4,908 and US$4,050, respectively.

PT Merpati Nusantara Airlines (Persero) ("MNA")

On October 27, 2009, MNA requested to restructure its payable. An agreement was made on October 17, 2011 through a meeting at MoSOE. As of September 30, 2019, and December 31, 2018, 2017, and 2016, the provision for impairment for these receivables amounting to US$18,569, and US$18,190, US$19,472 and US$19,550 respectively.

c. Trade payables

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
PT Wijaya Karya (Persero) Tbk.	7,664	-	-	16,927
PT Asuransi Jasa Indonesia (Persero)	4,887	6,279	-	-
PT Rekayasa Industri	8	8	200	36,873
PT Seamless Pipe Indonesia Jaya	-	739	-	-
Others	144,452	71,755	49,077	64,740
Total	**157,011**	**78,781**	**49,277**	**118,540**

d. Other payables

	September 30, 2019 (unaudited)	December 31, 2018	2017	2016
PLN and its subsidiaries	41	6,044	31,452	17,144
Others	32,420	47,967	25,173	33,803
Total	**32,461**	**54,011**	**56,625**	**50,947**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

e. Sales and other operating revenues

The Group made sales and other operating revenues to related parties for the nine-month periods ended September 30, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016. Sales to related parties represent 18%, 24% and 24%, 18%, 16% of the total sales and other operating revenues for the respective periods/years. The details are as follows:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Domestic sales of crude oil, natural gas, geothermal energy and oil products					
- Government-related entities	2,883,385	3,525,729	4,872,641	3,961,054	3,505,441
- Shareholder	401,096	472,222	450,879	401,299	367,301
- Associates	673	946	1,222	735	5,021
Subsidy reimbursements from the Government					
- Shareholder	3,654,557	4,333,335	5,632,468	3,572,084	2,568,844
Marketing fees					
- Shareholder	9,430	11,574	15,432	25,474	(257,485)
Revenues from other operating activities					
- Government-related entities	63,833	2,158,488	3,210,732	128,870	93,319
Total	**7,012,974**	**10,502,294**	**14,183,374**	**8,089,516**	**6,282,441**

f. Cost of goods sold

Purchases from related parties for the nine-month periods ended September 30, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016 represent 22%, 24%, 25%, 22% and 19% of the total cost of goods sold, for the respective periods/years. The details are as follows:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Crude oil and gas for shareholder	6,335,700	7,483,973	10,002,633	6,879,687	4,726,374
Oil products:					
Joint ventures	102,144	117,391	158,260	174,842	132,717
Associates	-	-	332,752	82,140	180,276
Government-related entities	-	-	-	-	1,238
Total	**6,437,844**	**7,601,364**	**10,493,645**	**7,136,669**	**5,040,605**

g. Compensation of key management and Board of Commissioners

Key management comprises the Board of Directors and other key management personnel who have significant involvement in the operations of the Company. The compensation paid or payable to key management and Board of Commissioners is shown below:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Salaries and other benefits	23,775	35,455	47,273	52,781	42,469

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

h. Relationship with related parties

The nature of relationships with the related parties is as follows:

Relationships	Related parties
• Shareholder	The Government of the Republic of Indonesia
• Associates	PPT Energy Trading Co.,Ltd. PT Trans-Pacific Petrochemical Indotama PT Donggi Senoro LNG PT Asuransi Samsung Tugu PT Gas Energi Jambi Seplat Petroleum Development Company Plc.
• Joint ventures	PT Patra SK PT Perta Samtan Gas PT Perta Daya Gas PT Indo Thai Trading (Note 1b) PT Transportasi Gas Indonesia PT Permata Karya Jasa (Perkasa) PT Pertamina Rosneft Pengelolaan dan Petrokimia
• Common key management	Koperasi Karyawan Pertamina Dana Pensiun Pertamina Pertamina Foundation Yayasan Kesehatan Pertamina
• Government-related entities	TNI POLRI Ministry of Finance PLN and its subsidiaries PT Pupuk Indonesia (Persero) PT Krakatau Steel (Persero) Tbk. PT Garuda Indonesia (Persero) Tbk. PT Merpati Nusantara Airlines (Persero) PT Wijaya Karya (Persero) Tbk. PT PAL Indonesia (Persero) PT Bina Bangun Wibawa Mukti PT Rekayasa Industri PT Asuransi Jasa Indonesia (Persero) PT Sarana Multi Infrastruktur (Persero) BNI BNI Syariah BRI BRI Syariah BRI Agroniaga Bank Mandiri Bank Syariah Mandiri PT Arun Natural Gas Liquefaction PT Badak Natural Gas Liquefaction Indonesian Eximbank State-Owned Enterprises Local Government-Owned Enterprises
• Key Management Personnel	Board of Directors Other key management of the personnel
• Governance Oversight Body	Board of Commissioners

42. SEGMENT INFORMATION

Management has determined the operating segments based on the reports reviewed by the strategic steering committee that are used to make strategic decisions.

Segments are grouped into two principal business activities consisting of Upstream and Downstream, representing the Company's reportable segments as defined in the accounting standards for segment reporting SFAS 5 (Amendment 2014), Operating Segments (Note 2v). Business activities related with Gas and New and Renewable Energy are currently grouped into Others segment because they still have not met quantitative thresholds as a reportable operating segment.

	September 30, 2019 (unaudited)					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	4,699,191	31,383,136	3,092,441	39,174,768	-	39,174,768
Inter-segment sales	4,191,296	478,272	131,754	4,801,322	(4,801,322)	-
Total segment revenues	8,890,487	31,861,408	3,224,195	43,976,090	(4,801,322)	39,174,768
Segment results**)	3,835,682	(1,336,160)	404,740	2,904,262	(23)	2,904,239
Gain (loss) on foreign exchange - net						140,511
Finance income						400,512
Finance costs						(721,197)
Share in net profit of associates and joint venture						59,722
Other expenses - net						(333,753)
						(454,205)
Profit before income tax						2,450,034
Income tax expense						(1,674,145)
Profit for the period after the effect of merging entity's income adjustment						**775,889**
Profit for the year attributable to:						
Owners of the parent						731,157
Non-controlling interests						44,732
Other Information						
Segment assets	28,050,000	28,854,438	6,668,196	63,572,634	(1,709,445)	61,863,189
Long-term investments	1,410,929	16,407,407	335,244	18,153,580	(15,480,151)	2,673,429
Total assets	29,460,929	45,261,845	7,003,440	81,726,214	(17,189,596)	64,536,618
Total liabilities	11,984,057	19,659,439	3,987,442	35,630,938	(849,078)	34,781,860
Depreciation, depletion and amortization expense	1,460,252	549,876	372,029	2,382,157	-	2,382,157
Additions to fixed assets, oil and gas, and geothermal properties	1,833,598	571,970	221,118	2,626,686	-	2,626,686

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	September 30, 2018 (unaudited)					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	7,988,396	34,504,788	694,525	43,187,709	-	43,187,709
Inter-segment sales	382,557	961,951	3,188,320	4,532,828	(4,532,828)	-
Total segment revenues	8,370,953	35,466,739	3,882,845	47,720,537	(4,532,828)	43,187,709
Segment results**)	4,367,177	607,996	484,872	5,460,045	(146,260)	5,313,785
Gain on foreign exchange - net						(190,420)
Finance income						159,658
Finance costs						(619,359)
Share in net profit of associates and joint venture						178,193
Other expenses - net						(109,959)
						(581,887)
Profit before income tax						4,731,898
Income tax expense - net						(2,042,682)
Profit for the period after the effect of merging entity's income adjustment						**2,689,216**
Profit for the year attributable to:						
Owners of the parent						2,550,072
Non-controlling interests						139,144
Other Information						
Segment assets	27,918,626	31,174,737	7,398,725	66,492,088	(5,573,350)	60,918,738
Long-term investments	1,341,535	17,479,049	390,407	19,210,991	(16,488,756)	2,722,235
Total assets	29,260,161	48,653,786	7,789,132	85,703,079	(22,062,106)	63,640,973
Total liabilities	13,724,235	23,537,426	3,821,266	41,082,927	(6,474,969)	34,607,958
Depreciation, depletion and amortization expense	1,283,168	522,281	414,179	2,219,628	-	2,219,628
Additions to fixed assets, oil and gas, and geothermal properties	1,608,287	713,598	362,176	2,684,061	-	2,684,061

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2018					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	7,054,464	45,691,622	5,187,485	57,933,571	-	57,933,571
Inter-segment sales	5,498,100	399,699	266,115	6,163,914	(6,163,914)	-
Total segment revenues	12,552,564	46,091,321	5,453,600	64,097,485	(6,163,914)	57,933,571
Segment results**)	5,960,645	(286,777)	616,351	6,290,219	(43,479)	6,246,740
Gain on foreign exchange - net						19,622
Finance income						256,573
Finance costs						(835,238)
Share in net profit of associates and joint venture						122,724
Other expenses - net						(80,825)
						(517,144)
Profit before income tax						5,729,596
Income tax expense						(3,013,202)
Profit for the period/year after the effect of merging entity's income adjustment						**2,716,394**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						2,572,542
Non-controlling interests						143,852
Other Information						
Segment assets	24,620,521	35,093,033	6,655,756	66,369,310	(4,469,912)	61,899,398
Long-term investments	1,472,711	14,970,480	183,158	16,626,349	(13,807,295)	2,819,054
Total assets	26,093,232	50,063,513	6,838,914	82,995,659	(18,277,207)	64,718,452
Total liabilities	10,092,998	26,403,047	3,636,191	40,132,236	(5,023,824)	35,108,412
Depreciation, depletion and amortization expense	1,684,534	715,492	576,536	2,976,562	-	2,976,562
Additions to fixed assets, oil and gas, and geothermal properties	3,110,810	1,135,645	287,056	4,533,511	-	4,533,511

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2017					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	4,489,320	37,000,553	4,510,850	46,000,723	-	46,000,723
Inter-segment sales	3,477,012	372,195	427,098	4,276,305	(4,276,305)	-
Total segment revenues	7,966,332	37,372,748	4,937,948	50,277,028	(4,276,305)	46,000,723
Segment results**)	3,327,892	1,282,198	759,793	5,369,883	(183,477)	5,186,406
Gain on foreign exchange - net						58,137
Finance income						233,074
Finance costs						(817,711)
Share in net profit of associates and joint venture						37,904
Other expenses - net						(830,582)
						(1,319,178)
Profit before income tax						3,867,228
Income tax expense - net						(1,166,824)
Profit for the period/year after the effect of merging entity's income adjustment						**2,700,404**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						2,621,732
Non-controlling interests						78,672
Other Information						
Segment assets	23,969,823	28,451,374	8,878,406	61,299,603	(6,831,146)	54,468,457
Long-term investments	1,476,703	16,490,057	451,653	18,418,413	(15,447,495)	2,970,918
Total assets	25,446,526	44,941,431	9,330,059	79,718,016	(22,278,641)	57,439,375
Total liabilities	12,148,638	21,037,697	4,165,216	37,351,551	(6,925,443)	30,426,108
Depreciation, depletion and amortization expense	1,507,444	692,767	603,798	2,804,009	-	2,804,009
Additions to fixed assets, oil and gas, and geothermal properties	3,672,689	1,529,130	221,357	5,423,176	-	5,423,176

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2016					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	3,542,516	32,337,198	3,932,223	39,811,937	-	39,811,937
Inter-segment sales	2,729,749	140,469	365,653	3,235,871	(3,235,871)	-
Total segment revenues	6,272,265	32,477,667	4,297,876	43,047,808	(3,235,871)	39,811,937
Segment results	2,065,679	4,176,180	501,669	6,743,528	(44,098)	6,699,430
Gain on foreign exchange - net						(57,521)
Finance income						336,634
Finance costs						(770,518)
Share in net profit of associates and joint venture						18,722
Other expenses - net						(877,864)
						(1,350,547)
Profit before income tax						5,348,883
Income tax expense						(1,877,649)
Profit for the period/year after the effect of merging entity's income adjustment						**3,471,234**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						3,320,382
Non-controlling interests						150,852
Other Information						
Segment assets	20,490,777	28,354,356	9,501,653	58,346,786	(7,700,131)	50,646,655
Long-term investments	1,714,743	14,331,318	511,081	16,557,142	(13,227,703)	3,329,439
Total assets	22,205,520	42,685,674	10,012,734	74,903,928	(20,927,834)	53,976,094
Total liabilities	9,422,068	19,894,950	5,185,541	34,502,559	(5,771,223)	28,731,336
Depreciation, depletion and amortization expense	1,568,763	653,572	465,905	2,688,240	-	2,688,240
Additions to fixed assets, oil and gas, and geothermal properties	1,566,871	801,312	644,562	3,012,745	-	3,012,745

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

Transactions between segments are carried out at agreed terms between the companies.

The following table shows the distribution of the Group's consolidated revenues based on its geographic segments:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Revenue					
Indonesia	36,690,788	40,519,587	54,296,618	44,126,442	38,843,566
Other countries	2,483,980	2,668,122	3,636,953	1,874,281	968,371
Consolidated revenues	**39,174,768**	**43,187,709**	**57,933,571**	**46,000,723**	**39,811,937**

Revenue from two customers of the downstream segment for the years ended September 30, 2019 and 2018 represented approximately 15% and 21% (US$5,729,336 and US$9,043,401) of total sales and other operating revenues, respectively.

All of the Group's assets are substantially located in Indonesia, except for several owned assets outside the country such as PIEP's Subsidiaries which are located in Algeria, Iraq, Malaysia, Italia, France, Myanmar, Canada, Congo, Tanzania, Gabon, Colombia, Namibia, and Venezuela, respectively.

43. OIL AND GAS CONTRACT ARRANGEMENTS

a. Conventional PSC

PSCs are entered into by PSC Contractors with SKK Migas (previously BP Migas) acting on behalf of the Government, for a period of 20-30 years, and may be extended in accordance with applicable regulations.

- **Working area**
  The PSC working area is a designated area in which the PSC contractors may conduct oil and gas operations. On or before the tenth year from the effective date of the PSCs, the PSC contractors must return a certain percentage of this designated working area to SKK Migas on behalf of the Government during the term of the PSC.

- **Crude oil and natural gas production sharing**

  Crude oil and natural gas production sharing is determined annually, representing the total liftings of crude oil and gas in each period/year, net of investment credit, FTP, and cost recovery.

  The PSC Contractors are subject to tax on their taxable income from their PSC operations based on their share of equity oil and natural gas production, less bonuses, at a combined tax rate comprising of corporate income tax and dividend tax.

- **Cost recovery**

  Annual cost recovery comprises of:
  i. Current year non-capital costs;
  ii. Current year amortization of capital costs; and
  iii. Unrecovered prior years' operating costs (unrecovered costs).

- **Crude oil and natural gas prices**

  The PSC Contractors' crude oil production is priced at ICP. Natural gas deliveries to third parties and related parties are valued based on the prices stipulated in the respective gas sales and purchase contracts.

- **DMO**

  Crude oil

  The PSC Contractors are required to supply the domestic market in Indonesia with the following annual calculation:

  i. Multiply the total quantity of crude oil produced from the contract area by a fraction, the numerator of which is the total quantity of crude oil to be supplied and the denominator is the entire crude oil production from all petroleum companies in Indonesia.
  ii. Compute 25% of the total quantity of crude oil produced in the PSC's working area.
  iii. Multiply the lower computed, either under (i) or (ii) by the percentage of the contractor's entitlement.

  The price of DMO crude oil is equal to the weighted average of all types of crude oil sold by the PSC Contractors or other price determined under the PSC.

  Natural gas

  The PSC Contractors are required to supply the domestic market in Indonesia with 25% of total quantity of natural gas produced in the working area multiplied by the PSC contractor's entitlement percentage.

  The price of DMO for natural gas is the price determined based on the agreed contracted sales price.

- **FTP**

  The Government and Contractors are entitled to receive an amount ranging from 10%-20% of the total production of crude oil and natural gas each year, before any deduction for recovery of operating costs and investment credit.

- **Ownership of materials, supplies, and equipment**

  Materials, supplies, and equipment acquired by the PSC contractors for crude oil and natural gas operations belong to the Government. However, the PSC contractors have the right to utilize such materials, supplies, and equipment until they are declared surplus or abandoned with the approval of SKK Migas.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

b. PT Pertamina EP cooperation agreements with SKK Migas

On September 17, 2005, an oil and gas cooperation contract in the form of Pertamina Oil and Gas Contract which is equivalent to a PSC, was signed between Special Task Force For Upstream Oil and Gas Bussiness Activities ("SKK Migas" formerly Oil and Gas Upstream Activities Agency/"BP Migas") and PT Pertamina EP as a successor contract to Pertamina's Petroleum Contract (PPC).This is valid for a period of 30 years from September 17, 2005 until September 16, 2035, which may be extended in accordance with a written agreement between the parties (SKK Migas and PT Pertamina EP) and approval from the Government.

PT Pertamina EP's cooperation contract has the following financial provisions:

- **Working area**

  The area represents the former Pertamina Entity's exploration and production areas excluding Cepu and Randugunting Blocks.

- **Crude oil and natural gas production sharing**

  PT Pertamina EP and the Government's shares of equity (profit) of oil and gas production is 67.2269% and 32.7731%, respectively.

- **FTP**

  The Government and PT Pertamina EP are entitled to receive an amount equal to 5% of the total production of oil and gas each year before any deduction for recovery of operating costs and investment credit. FTP is shared between the Government and PT Pertamina EP in accordance with the entitlements to oil and gas production.

- **Crude and natural gas price**

  Sales of Company's crude are valued with ICP. Transfer of natural gas are valued with decreed price in Gas Sales Agreement ("GSA").

c. PT Pertamina EP cooperation agreements with other parties

PT Pertamina EP has entered into cooperation agreements with other parties in conducting oil and gas activities in certain parts of its PSC working area, under TAC or operating cooperation contracts with the approval of the Government through SKK Migas.

The recoverable costs and shares of equity (profit) of the other parties under the following cooperation agreements form part of PT Pertamina EP's cost recovery under its PSC.

Cooperation agreements with other parties are as follows:

i. Technical Assistant Contract ("TAC")

Under a TAC, operations are conducted through partnership arrangements with PT Pertamina EP. TACs are awarded for fields which are currently in production, or which had previously been in production, but the production has ceased. Crude oil and natural gas production is divided into non-shareable and shareable portions. The non-shareable portion represents the production which is expected from the field (based on the historic production trends of the field) at the time the TAC is signed and accrues to PT Pertamina EP. Non-shareable production decreases annually reflecting expected declines in production. The shareable portion of production corresponds to the additional production resulting from the Partners' investments in the TAC fields.

The Partners are entitled to recover costs, subject to specified annual limitations depending on the contract terms. The remaining portion of shareable production (shareable production less cost recovery) is split between PT Pertamina EP and the Partners. The Partners' share of equity (profit) oil and gas production is stipulated in each contract and ranges from 26.7857% to 35.7143% for oil and 62.5000% for gas.

As of September 30, 2019, there are 7 TAC arrangements of PT Pertamina EP for Sumatera, Java and Papua working areas with contract term for 20 years. The effective term of those contracts range from 2000 until 2002 and the end term of those contracts range from 2020 until 2022.

At the end of the TACs, all TAC assets are transferred to PT Pertamina EP. The TAC Partners are responsible for settling all outstanding TAC liabilities to third parties until the end of the TACs.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

c. PT Pertamina EP cooperation agreements with other parties (continued)

ii. Operation Cooperation Contract ("OC")

In an OC Contract, operations are conducted through partnership arrangements with PT Pertamina EP. OC Contracts are awarded for fields which are currently in production, or which have previously been in production, in which production has ceased, or for areas with no previous production. The two types of OC contracts are:
a. OC Production - Exploration contract
b. OC Production contract

Under an OC Production-Exploration contract, there is no Non-Shareable Oil. While for an OC Production contract, the crude oil production is divided into non-shareable and shareable portions.

The NSO portion of crude oil production represents the production which is expected from the field (based on the historic production trends of the field) at the time the OC contract is signed, and it accrues to PT Pertamina EP. The shareable portion of crude and gas production corresponds to the additional production resulting from the Partners' investments in the OC contract fields and split between the parties in the same way as under a cooperation contract. In certain OC production contracts, in the event that the production is the same as or less than the NSO, the Partner's production cost shall not be deferred and will be recovered with the following provisions:

Partner may recover the operating costs in any Calendar Year if the amount of the Partner's production is greater than the Non-Sharable Oil up to a maximum of Incremental Oil that comprises of:

1) Cost recovery for lifting Non-Shareable Oil up to a maximum of 80% (eighty percent) from Operating Costs of Non-Shareable Oil.

2) Cost recovery for lifting incremental oil up to a maximum of 80% (eighty percent) from the production of Incremental Oil produced and sold and that were not used in that Calendar Year.

If, in any Calendar Year, the operating costs exceed the value of such crude oil allocated for the Operations in that Calendar Year, then the unrecovered excess will be recovered in the following years.

The Partner's share of equity (profit) oil and gas production as stipulated in each contract ranges from 16.6667% to 29.8039% for oil and 28.8627% to 53.5714% for gas, respectively.

Specified investment expenditure commitments are required to be made in the first three years after the signing of the OC contract. To ensure that these expenditure commitments are met, the Partners are required to provide PT Pertamina EP with irrevocable and unconditional bank guarantees. The OC Partners are also required to make payments to PT Pertamina EP before the date of signing the OC contracts, of the amounts stated in the bid documents.

As of September 30, 2019, there are 24 OC partnership arrangements of PT Pertamina EP for Sumatera, Java, Kalimantan and Papua working area with contract term for 15-20 years. The effective term of those contracts range from 2007 until 2018 and the end term of those contracts range from 2022 until 2035.

At the end of OC contracts, all OC assets are transferred to PT Pertamina EP. The OC Partners are responsible for settling all outstanding OC liabilities to third parties until the end of the OC contracts.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

c. PT Pertamina EP cooperation agreements with other parties (continued)

iii. Unitisation Agreement

In accordance with Government Regulation No. 35 Year 2004 on Upstream Oil and Gas Business Activities, a PSC contractor is required to conduct unitisation if it is proven that its reservoir extends into another contractor's Working Area. The MoEMR will determine the operator for the unitisation based on the agreement between the contractors entering the unitisation after considering the opinion of SKK Migas.

As of September 30, 2019, there are 6 Unitisation arrangements of PT Pertamina EP for Sumatera, Java and Papua working area with contract term for 10-50 years. The effective term of those contracts range from 1985 until 2013 and the end term of those contracts range from 2023 until 2035.

Based on SKK Migas Letter No. SRT-0493/SKKMA0000/2018/S1 dated June 25, 2018, regarding the Establishment of New Unitization Operators in Sukowati Field, CPA Mudi Production Facilities and FSO Cinta Natomas, the PT Pertamina EP was appointed as the new operator Sukowati Field (Note 4h).

d. PHE's cooperation agreement with other parties

- Gross split contract

On January 13, 2017, the regulation of the Minister of Energy and Mineral Resources No.08/2017 regarding principles of the PSC without Cost Recovery Mechanism, also known as Gross Split PSC was issued.

In Gross Split PSC the sharing of oil and gas production between the Government of Indonesia and the Contractors is based on the following 3 criteria:

1. Base Split
2. Variable Split
3. Progressive Split

The Government has also arranged matters related to Gross Split PSC as follows:

i. The tax regime applicable to the Gross Split PSC is in accordance with the provisions of the income tax law;
ii. The contractors of Gross Split PSC must reimburse unrecovered investment costs to the old PSC contractors.
iii. The oil and gas assets of the old PSC which are now owned by the Directorate General of State Assets ("DJKN") are to be used by the Gross Split PSC contractors based on lease scheme.
iv. Leases are levied on oil and gas assets used by the Gross Split PSC contractors and have the cost recovery, then the fair value is recalculated based on the Indonesian Appraisal Standard by the Public Appraiser, multiplied by the rental rate set by the DJKN.

As of September 30, 2019, the signed gross split PSC is as follows:

PSC partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
MUJ ONWJ	Offshore North West Java Block	North West Java	19/01/2017	27/08/1971	18/01/2037	90%	Oil and gas	20 years
None	Tuban Block	East Java	20/05/2018	12/02/1997	19/05/2038	100%	Oil and gas	20 years
None	Ogan Komering Block	South Sumatera	20/05/2018	11/07/1991	19/05/2038	100%	Oil and gas	20 years
None	Offshore Southeast Sumatera Block	Southeast Sumatera	06/09/2018*	1975	05/09/2038	100%	Oil and gas	20 years
None	NSO Block	North Sumatera Offshore	17/10/2018*	01/10/2015	16/10/2038	100%	Oil and gas	20 years
None	Raja/Pendopo Block	South Sumatera	06/07/2019**	21/11/1992	05/07/2039	100%	Oil and gas	20 years
None	Jambi Merang Block	Jambi	10/02/2019**	22/02/2011	09/02/2039	100%	Oil and gas	20 years
Eni East Sepinggan Ltd.	East Sepinggan Block	East Kalimantan	20/07/2012***	-	19/07/2042	15%	Oil and gas	30 years

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

d. PHE's cooperation agreement with other parties (continued)

PSC partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
None	Maratua Block	North & East Kalimantan	18/02/2019	-	17/02/2049	100%	Oil and gas	30 years
Petrogas (Basin) Ltd.	Kepala Burung Block	Papua	15/10/2020****	07/10/1996	14/10/2040	30%	Oil and gas	20 years
Petrogas (Island) Ltd.	Salawati Block	Papua	23/04/2020****	21/01/1993	22/04/2040	30%	Oil and gas	20 years

* Gross Split PSC was signed on April 20, 2018
** Gross Split PSC signed on May 31, 2018
*** The amended and restated to Gross Split PSC was signed on December 11, 2018
**** Gross Split PSC was signed on July 11, 2018

- **Indonesian participation arrangements ("IP")**

  Through the IP arrangements, the Company, a State-Owned Enterprise, is offered a 10% working interest in PSCs at the first time Plans of Development ("POD") which was approved by the Government of Indonesia (the "Government"), represented by SKK Migas. The 14.28% interest in Jabung Block represents the acquisition of additional interest of 4.28% by the Company. The 5% interest in the Tengah Block represents 10% of the 50% foreign contractor's share. The Company assigned these IP interests to PHE's subsidiaries on January 1, 2008.

  As of September 30, 2019, there are 5 IP partnership arrangements of PHE for Sumatera, Kalimantan and Papua working area with contract terms of 20-30 years. The effective term of those contracts ranges from 1990 until 2005 and the end term of those contracts ranges from 2020 until 2028 with percentage of participation range from 10% until 14.28%.

- **PSC interests acquired after the issuance of Law No.22 year 2001, related to Oil and Gas**

  1. **Oil and gas**

     As of September 30, 2019, there are 16 oil and gas partnership arrangements of PHE for Sumatera, Java, Kalimantan, Sulawesi, Maluku and Papua working area with contract terms of 20-30 years. The effective term of those contracts range from 2002 until 2018 and the end term of those contracts ranges from 2020 until 2046 with percentage of participation ranging from 15% until 100%.

  2. **Coal bed methane**

     As of September 30, 2019, there are 13 Coal Bed Methane ("CBM") partnership arrangements in exploration activities for Sumatera and Kalimantan working areas, with contract terms of 30 years. The effective terms of those contracts ranges from 2008 until 2012, and the end term of those contracts ranges from 2038 until 2042 with percentages of participation range from 27.5% until 100%.

  3. **Unconventional oil and gas**

     As of September 30, 2019, there are 2 Unconventional Oil and Gas partnership arrangements for Sumatera working areas with contract term of 30 years. The effective term of those contracts ranges from 2013 until 2015, and the end term of those contracts ranges from 2043 until 2045 with percentages of participation interests range from 50% until 100%.

- **Joint operating body-production sharing contracts ("JOB-PSC")**

  In a JOB-PSC, operations are conducted by a joint operating body between PHE's Subsidiaries and the contractors. The PHE Subsidiaries' share of expenditures is paid in advance by the contractors and repaid by PHE's Subsidiaries out of their share of crude oil and natural gas production, with a 50% uplift. After all expenditures are repaid, the crude oil and natural gas production is divided between PHE's subsidiaries and the contractors based on their respective percentages of participation in the JOB-PSC. The contractors' share of crude oil and natural gas production is determined in the same manner as for a PSC.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

d. PHE's cooperation agreement with other parties (continued)

- Joint operating body-production sharing contracts ("JOB-PSC") (continued)

As of September 30, 2019, there are 3 JOB-PSC Partnership arrangements of PHE for Kalimantan, Sulawesi, and Papua working area with contract terms of 30 years. The effective term of those contracts ranges from 1990 until 1998, and the end term of those contracts ranges from 2020 until 2028 with percentage of participation ranging from 37.5% until 50%.

- Pertamina participating interests ("PPI")

Through PPI arrangements, PHE owns working interests in contracts similar to JOB-PSC contracts. The remaining working interests are owned by a contractor who acts as an operator. PHE's share of expenses is either funded by PHE on a current basis, or paid in advance by the contractors and repaid by PHE out of their share of crude oil and natural gas production, with a 50% uplift. The crude oil and natural gas production are divided between PHE and the contractors based on their respective percentages of participation in the PSC. The contractors' share of crude oil and natural gas production is determined in the same manner as for a PSC.

As of September 30, 2019, the Subsidiaries' PPI arrangements were as follows (unaudited):

PPI partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
Conoco Philips (South Jambi) Ltd. and Petrochina International Jambi B Ltd.	B Block	South Jambi	26/01/1990	26/09/2000	25/01/2020	25%	Oil and gas	30 years

- Foreign oil and gas contract interests

Name of JOC	JOB partners	Working area	Area	Effective date of contract	Production commencement date	Percentage of participation	Production	Contract period
Petronas Carigali Pertamina Petro-Vietnam Operating Company Sdn. Bhd. ("PCPP")	Petronas Carigali Sdn. Bhd., Petrovietnam	Offshore Sarawak Block (SK 305)	Malaysia	16/06/2003	26/07/2010	30%	Oil and gas	29 years

- Unitization agreements

In accordance with Government Regulation No. 35 Year 2004 on Upstream Oil and Gas Business Activities, a contractor is required to conduct unitization if it is proven that its reservoir extends into another Contractor's Working Area. The MoEMR will determine the operator for the unitization based on the agreement between the contractors entering the unitization agreements after considering the opinion of SKK Migas.

Since several of PHE Subsidiaries' oil and gas reservoirs extend into other Contractors' Working Areas, PHE Subsidiaries entered into unitization agreements with several contractors.

As of September 30, 2019, there are 6 unitization agreements of PHE for Sumatera, Java, and Papua working areas, with contract terms ranging from 10-50 years. The effective term of those contracts ranges from 1985 until 2019, and the end term of those contracts ranges from 2023 until 2038.

- Extension and termination of PHE cooperation contract

PSC "B" ended on October 3, 2018. On September 25, 2018, the Government, through the Aceh Oil and Gas Management Agency ("BPMA"), appoints PHE NSB as operator of the "B" Working Area for several period amendment, with the latest amendment were for 1 (one) year up to November 17, 2020 or until PSC has just been signed, whichever occurs first, with the basic forms and provisions of PSC in accordance with the current "B" working area (Note 50g).

The Tengah Block PSC ended on October 4, 2018. The Government decides not to extend the management of the Tengah Working Area by the existing Contractor. Until these consolidated financial statements were prepared, PHE Tengah K together, with other contractors (Total Tengah and Inpex Tengah Ltd.), are still in the process of completing their rights and obligations after termination with the Government.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

e. PT Pertamina EP Cepu (PEPC)'s cooperation agreements with other parties

On September 17, 2005, a Cooperation Contract ("PSC") was signed between SKK Migas and PEPC (50% participating interest), MCL (25.50% participating interest) and Ampolex (24.50% participating interest) (jointly called a Contractor) for a period of 30 years from September 17, 2005 to September 16, 2035, and may be extended in accordance with applicable regulations. The conditions for PSC PEPC are as follows:

PSC Partner	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
ExxonMobil Cepu Limited Ampolex (Cepu) Pte. Ltd. PT Sarana Patra Hulu Cepu PT Petrogas Jatim Utama Cendana PT Blora Patragas Hulu PT Asri Dharma Sejahtera	Cepu Block	Central Java East Java	17/09/2005	31/08/2009	16/09/2035	45%	Oil	30 years

- Unitisation agreements

As of September 30, 2019, the Subsidiaries' unitization agreements are as follows:

Partner	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
PT Pertamina EP	EP Block Cepu Block	East Java	17/09/2005	-	16/09/2035	91.9399%	Gas	30 years

f. PT Pertamina EP Cepu Alas Dara Kemuning (PEPCADK) cooperation agreements with SKK Migas

The PSC was entered into by PEPC ADK with SKK Migas action on behalf of the Government on February 26, 2014 for a period of 30 years from February 26, 2014 until February 25, 2044. The period may be extended in accordance with applicable regulations. The Company has a 100% participating interest in the Alas Dara Kemuning Block PSC.

g. PT Pertamina Hulu Indonesia ("PHI") cooperation agreements with SKK Migas

- PSC

PSC is made by PSC contractors with the Government through the Special Task Force for Upstream Oil and Gas Business Activities ("SKK Migas" - formerly the Executive Agency for Upstream Oil and Gas Business Activities/"BP MIGAS") for a contract period of 20-30 years . This period can be extended in accordance with applicable regulations.

As of September 30, 2019, PHI Group's PSC are as follows:

PSC partner	Working area	Area	Contract effective date	Starting production date	Expiry date of contract	Partnership percentage	Production	Contract period
None	Mahakam Block	Onshore and Offshore East Kalimantan	01/01/2018	01/01/2018	31/12/2037	100%	Oil and gas	20 years

- Gross Split PSC

PSC partner	Working area	Area	Contract effective date	Starting production date	Expiry date of contract	Partnership percentage	Production	Contract period
None	Sanga Sanga Block	Onshore East Kalimantan	08/08/2018*	08/08/2018	07/08/2038	100%	Oil and gas	20 years
None	East Kalimantan and Attaka Block	Onshore and Offshore East Kalimantan	25/10/2018*	25/10/2018	24/10/2038	100%	Oil and gas	20 years

* Contract was signed on April 20, 2018.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

g. PT Pertamina Hulu Indonesia ("PHI") cooperation agreements with SKK Migas (continued)

- Unitisation agreements

As of September 30, 2019, PHI's has unitisation agreements as follows:

Parties	Operator	Field	Location	Signing date of contract	Start contract	Production	End contract	Contract period
PT Pertamina Hulu Mahakam (PHM) & Pertamina Hulu Sanga Sanga (PHSS)	PT Pertamina Hulu Sanga Sanga (PHSS)	Nilam & Badak	East Kalimantan (KKS Mahakam and KKS Sanga Sanga)	23/10/2019	08/08/2018	08/08/2018	31/12/2037	20 years
PT Pertamina Hulu Mahakam (PHM) & Pertamina Hulu Kalimantan Timur (PHKT)	PT Pertamina Hulu Mahakam (PHM)	Peciko	East Kalimantan (KKS Mahakam and KKS East Kalimantan)	In Progress	25/10/2018	25/10/2018	31/12/2037	20 years

h. PIEP's directly and indirectly held foreign oil and gas PSC interests

As of September 30, 2019, the Company's directly and indirectly held foreign oil and gas PSCs or similar interests were as follows:

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commencement of production	Percentage of participation	Production	Contract period
Menzel Lejmat North (MLN)	Talisman (Algeria) B.V.	405a Block	Algeria	2000	2003	65%	Oil	25 years
PTTEP HK Offshore Limited	PTTEP HK Offshore Limited Petronas Carigali Sdn. Bhd.	K Block	Malaysia	27/01/1999	2007	24%	Oil and natural gas	38 years
PTTEP HK Offshore Limited	PTTEP HK Offshore Limited Petronas Carigali Sdn. Bhd.	H Block	Malaysia	19/03/2007	Development stage	24%	Natural gas	38 years
PTTEP HK Offshore Limited	PTTEP HK Offshore Limited Petronas Carigali Sdn. Bhd.	SK309	Malaysia	27/01/1999	2003	Rotan 24% Others 18%	Oil, natural gas, and condensate	29 years
PTTEP HK Offshore Limited	PTTEP HK Offshore Limited Petronas Carigali Sdn. Bhd.	SK311	Malaysia	27/01/1999	2007	25.5%	Oil, natural gas, and condensate	29 years
PTTEP HK Offshore Limited	PTTEP HK Offshore Limited Petronas Carigali Sdn. Bhd.	SK314A	Malaysia	07/05/2013	Exploration stage	25.5%	-	27 years
Mnazi Bay Exploration & Mnazi Bay Development/ Production	M&P (Operator); Wenthworth; TPDC	Mnazi Bay	Tanzania	October 2006	August 2015	60.075% & 48.06%	Gas	2031 and can be extended up to 2051
Enzanga Production	M&P (Operator); The Gabonese Republic; Tullow	Ezanga	Gabon	01/01/2014	2007	80%	Oil	2034 and can be extended up to 2054
Seplat Petroleum Development Company Plc	Seplat (Operator); NPDC	OML 4, 38, 41	Nigeria	June 1989	July 2010	45%	Oil and gas	October 2038
Seplat Petroleum Development Company Plc	Pillar Oil (Operator); Seplat	OPL 283	Nigeria	2009	May 2012	40%	Oil	Oktober 2028
Seplat Petroleum Development Company Plc	Seplat and NNPC (Joint Operators)	OML 53	Nigeria	1997	1978	40%	Oil	June 2027
Seplat Petroleum Development Company Plc	Seplat and Belema Oil (Joint Operators); NNPC	OML 55	Nigeria	1997	February 2017	n/a*)	Oil	June 2027
-	Sonangol Pesquisae Producao (Sonangol P&P) China Songol, Eni, Sumoil (Angola), NIS (Serbia) and INA (Croatia)	3/05 Block 3/05A Block	Angola	28/09/2005	1980	20%	Oil	2025
Petroregional del Lago Mixed Company	Petroleos de Venezuela S.A. ("PDVSA"); PDVSA Social	Urdaneta West Field	Venezuela	2006	1974	40%	Oil	2026

*) Under the revised commercial terms in relation to OML 55, starting July 2016, Seplat will no longer be a shareholder in BelemaOil but will instead receive interest income until a total sum of US$330 million has been paid to Seplat. Working interest production reported for OML 55 is preceding volumes to end June 2016.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

h. PIEP's directly and indirectly held foreign oil and gas PSC interests (continued)

- **Technical service contract ("TSC")**

As of September 30, 2019, TSC participating interest held by PT Pertamina Irak Eksplorasi Produksi ("PIREP") were as follows:

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commence-ment of production	Percentage of participation	Production	Contract period
West Qurna 1 Field Operating Division	ExxonMobil Iraq Limited, Itochu Oil Exploration (Iraq) B.V., PetroChina International Iraq FZE, Oil Exploration Company of Iraqi Ministry of Oil	West Qurna 1 Block	Iraq	25/01/2010	25/01/2010	10%	Oil	35 years

- **Unitisation agreements**

As of September 30, 2019, PIEP's unitization agreements are as follows:

1. Algeria

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commence-ment of production	Percentage of participation	Production	Contract period
El Merk ("EMK")	Talisman (Algeria) B.V., Sonatrach, Anadarko, Eni, Maersk	405a Block	Algeria	18/03/2007	2013	16.90%	Oil, Condensate, and LPG	25 years
Ourhoud	Talisman (Algeria) B.V., Sonatrach, Anadarko, Eni, Maersk, Cepsa	405a Block	Algeria	December 1997	2002	3.56%	Oil	25 years

2. Malaysia

Parties	Operator	Unit field	PMEP's percentage of participation	Effective date of contract	Date of commencement of production	Production	Contract period
Shell, Conoco Phillips Sabah Ltd, Petronas Carigali Sdn Bhd Murphy Sabah Oil Co., PMEP	Sabah Shell Petroleum Company Limited	Gumusut Kakap Field	3.25%	20/09/2004	18/11/2012	Oil and natural gas	Not specified
Shell, Conoco Phillips Sabah Ltd, Petronas Carigali Sdn Bhd Murphy Sabah Oil Co., PMEP	Murphy Sabah Oil Co.	Siakap North Petai Field	9.6%	01/01/2007	28/02/2014	Oil and natural gas	Not specified

i. PGN Cooperation Agreement

As of September 30, 2019, PGN has interests in the following oil and gas joint operations or Service Contracts Participation and Economic Sharing Agreements:

Working area	Country	Participating interest
Ujung Pangkah Block	Indonesia	100.00%
South Sesulu Block	Indonesia	100.00%
Fasken Block	United States of America	36.00%
Bangkanai Block	Indonesia	30.00%
West Bangkanai Block	Indonesia	30.00%
Muriah Block	Indonesia	20.00%
Ketapang Block	Indonesia	20.00%
Muara Bakau Block	Indonesia	11.67%
Wokam II Block	Indonesia	100.00%
Pekawai Block	Indonesia	100.00%
West Yamdena Block	Indonesia	100.00%

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

j. Rokan Cooperation Agreement

In connection with the Decree of the MoEMR of the Republic of Indonesia Number: 1923k/10/MEM/2018 regarding the Approval of Management and Determination of the Forms and Terms and Conditions of the Cooperation Contract in the Rokan Working Area dated August 6, 2018, it was decided that The Rokan working area cooperation contract which will expire on August 8, 2021 is not extended and PT Pertamina (Persero) or its affiliates are designated as managers of the Rokan Work Area after August 8, 2021.

The signature bonus that must be paid before signing the Rokan PSC is US$783,980 and was paid on December 21, 2018. The Rokan PSC was signed on May 9, 2019, by the Special Task Force for Upstream Oil and Gas Business Activities ("SKK Migas") and PT Pertamina Hulu Rokan (PT PHR). PSC contracts effective on August 9, 2021 with the concept of Gross Split.

Profit sharing for the contractor's part is as follows:

Oil/Natural Gas	New/Existing	Field Type	Contractor Share	Government Share
Oil	New Field	All Fields	57% + Var. Comp. Correction + Progr. Comp. Correction	43% + Var. Comp. Corection + Progr. Comp. Correction
Oil	Existing Field	Duri Fields	65%	35%
Oil	Existing Field	Non-Duri Fields	61%	39%
Natural Gas	New Field	All Fields	52% + Var. Comp. Correction + Progr. Comp. Correction	48% + Var. Comp. Corection + Progr. Comp. Correction
Natural Gas	Existing Field	Duri Fields	70%	30%
Natural Gas	Existing Field	Non-Duri Fields	66%	34%

44. GEOTHERMAL WORKING AREAS

Since 1974, the former Pertamina Entity has been assigned geothermal working areas in Indonesia based on various decision letters issued by the Minister of Mines and Energy. In accordance with Government Regulation No. 31 Year 2003, all rights and obligations arising from the contracts and agreements entered into between former Pertamina Entity and third parties, so long as these are not contrary to Law No. 22 Year 2001, were transferred to Pertamina Entity effective September 17, 2003. Pertamina Entity through its letter No. 282/C00000/2007-S0 dated March 12, 2007 assigned its geothermal working areas to PGE effective from January 1, 2007. The transfer of Pertamina Entity's rights, obligations, and interests in geothermal business operations to PGE was approved by the MoEMR in Letters No. 2198/30/DJB/2009 dated August 4, 2009 and No. 2523/30/DJB/2009 dated September 1, 2009.

Effective from June 28, 2010, Pertamina Entity's geothermal assets were transferred to PGE, and formed part of Pertamina Entity's contribution to PGE's additional paid-up capital. This transfer of Pertamina Entity's geothermal assets were documented in Notarial Deed No. 23 dated June 28, 2010 of Lenny Janis Ishak, S.H.

Based on the Decree of the Minister of Mines and Energy No. 2067 K/30/MEM/2012, regarding the affirmation of the territory of power and changes in the coordinate boundaries of the exploitation of geothermal resources, PT Pertamina Geothermal Energy has management rights over 14 geothermal WKPs. Referring to the original provision the Law No. 21 article 78 of 2014 regarding Geothermal Energy, at the end of 2014, 2 (two) WKPs, namely Kotamobagu and Gunung Iyang Argopuro were returned to the Government because the two WKPs up to December 31, 2014, were still not in the Exploitation stage. Furthermore, Pertamina received two (2) new WKPs, namely Mount Lawu (based on ESDM Ministerial Decree No.35.K/30/MEM/2016) and Seulawah (based on the Auction Winner Determination Letter from Aceh Governor No. 541/53157 November 1, 2013). PGE will carry out exploration activities in the two new WKPs.

44. GEOTHERMAL WORKING AREAS (continued)

The operations of the above geothermal working areas are conducted through own operations and joint operating contracts.

As of September 30, 2019, PGE's geothermal working areas were as follows:

a. Own operation

The following working areas are operated by PGE:

Working area	Location	Field status
Gunung Sibayak-Gunung Sinabung	Sibayak, North Sumatra	Production
Kamojang-Darajat	Kamojang, West Java	Production
Lahendong	Lahendong, North Sulawesi	Production
Gunung Way Panas	Ulubelu, Lampung	Production
Karaha-Cakrabuana	Karaha, West Java	Production
Lumut Balai dan Marga Bayur	Lumut Balai, South Sumatera	Development
Hululais	Hululais, Bengkulu	Development
Sungai Penuh	Sungai Penuh, Jambi	Exploration
Gunung Lawu	Central Java	Exploration
Seulawah Agam	Aceh	Exploration

b. Joint operating contracts ("JOCs")

JOCs include geothermal activities in PGE's working areas that are conducted by third parties. In accordance with the JOCs, PGE is entitled to receive production allowances from the JOC contractors at the rate of 2.66% for the Darajat JOC and 4% for the Salak, Wayang Windu, Sarulla, and Bedugul JOCs of the JOC contractors' annual net operating income as calculated in accordance with the JOCs.

As of September, 2019, PGE's JOCs were as follows:

Working area	Location	Field status	Contractor
Cibeureum - Parabakti	Salak, West Java	Production	Star Energy Geothermal Salak Ltd. and Star Energy Geothermal Salak Pratama Ltd.
Pangalengan	Wayang Windu, West Java	Production	Star Energy Geothermal (Wayang Windu) Ltd.
Kamojang-Darajat	Darajat, West Java	Production	Star Energy Geothermal Darajat II Ltd.
Gunung Sibualbuali	Sarulla, North Sumatera	Production	Sarulla Operation Limited
Tabanan	Bedugul, Bali	Exploration	Bali Energy Ltd.

PGE's income from geothermal activities is subject to tax (government share) at the rate of 34% for the Work Area managed before the Law No. 21 of 2014 regarding Geothermal was issued.

45. GOVERNMENT AUDIT

PT Pertamina EP, PT Pertamina EP Cepu, subsidiaries of PT Pertamina Hulu Energi

The accounting policies stipulated in the PSC are subject to interpretation by SKK Migas and the Government. Every year, the accounting records and financial information from all PSC are subject to audit by SKK Migas and/or the Government. Claims arising from the audit will be approved by the PSC operator and recorded in accounting accounting by the PSC or further discussed with SKK Migas and/or the Government. The settlement of the claims discussed requires a long negotiation process.

Management believes that the audit results for PT Pertamina EP Cooperation Contract and other PSC, wherein PT Pertamina EP Cepu and the subsidiaries of PT Pertamina Hulu Energi have the a Participating Interest, will not have a material impact on the Group's financial position and cash flows.

46. ADDITIONAL INFORMATION RELATED TO CASH FLOW

a. Activities that do not affect cash flow

	September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Increase/decrease in finance lease assets under fixed assets (Note 13)	(27,266)	19,828	103,022	(5,287)
Capitalization of borrowing costs to fixed assets (Note 13)	13,205	31,500	25,611	16,689
Capitalization of borrowing costs to oil and gas and geothermal properties	19,726	24,885	32,338	33
Addition (deduction) in oil and gas property arising from provision for decommissioning and site restoration (Note 23)	60,945	87,035	51,498	82,270

b. Reconciliation of liabilities from financing activities

	January 1, 2019	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	September 30, 2019 (unaudited)
Short-term loans	4,347,035	(2,620,786)	-	539	191,498	1,918,286
Dividend payable	-	(317,270)	552,659	8,014	-	243,403
Long-term liabilities	2,225,877	(103,253)	-	(2,827)	(82,747)	2,037,050
Bonds payable	11,094,096	1,498,855	-	-	21,271	12,614,222
Total liabilities from financing activities	**17,667,008**	**(1,542,454)**	**552,659**	**5,726**	**130,022**	**16,812,961**

	January 1, 2018	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2018
Short-term loans	452,879	3,905,941	-	(11,785)	-	4,347,035
Dividend payable	-	(585,755)	614,939	(29,184)	-	-
Long-term liabilities	2,475,726	(209,420)	-	(46,045)	5,616	2,225,877
Bonds payable	10,385,873	696,758	-	-	11,465	11,094,096
Total liabilities from financing activities	**13,314,478**	**3,807,524**	**614,939**	**(87,014)**	**17,081**	**17,667,008**

	January 1, 2017	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2017
Short-term loans	230,293	252,810	-	(30,224)	-	452,879
Dividend payable	-	(867,751)	907,383	(39,632)	-	-
Long-term liabilities	3,439,109	(820,834)	-	(148,909)	6,360	2,475,726
Bonds payable	9,772,656	-	-	-	613,217	10,385,873
Total liabilities from financing activities	**13,442,058**	**(1,435,775)**	**907,383**	**(218,765)**	**619,577**	**13,314,478**

46. ADDITIONAL INFORMATION RELATED TO CASH FLOW (continued)

b. Reconciliation of liabilities from financing activities (continued)

	January 1, 2016	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2016
Short-term loans	1,807,955	(1,680,626)	-	102,964	-	230,293
Dividend payable	-	(554,859)	499,449	55,410	-	-
Long-term liabilities	4,065,515	(573,920)	-	(55,858)	3,372	3,439,109
Bonds payable	9,910,726	(139,756)	-	-	1,686	9,772,656
Total liabilities from financing activities	**15,784,196**	**(2,949,161)**	**499,449**	**102,516**	**5,058**	**13,442,058**

47. FINANCIAL ASSETS AND LIABILITIES

a. Financial instruments category and fair value measurements

The following tables from to the Group's financial assets and liabilities by category:

	Financial Assets: Fair value through profit or loss	Available for sale	Loan and receivable	Held to maturity	Total
September 30, 2019 (unaudited)					
Cash and cash equivalents	-	-	8,094,779	-	8,094,779
Restricted cash	-	-	239,461	-	239,461
Short-term investments	30,195	415,831	16,670	-	462,696
Other investments	-	74,126	-	-	74,126
Long-term investments	-	16,035	1,537	531,269	548,841
Trade receivables	-	-	3,743,077	-	3,743,077
Due from the Government	-	-	5,280,429	-	5,280,429
Other receivables	-	-	1,215,061	-	1,215,061
Other non-current assets	-	-	1,329,229	-	1,329,229
Total Financial Assets	**30,195**	**505,992**	**19,920,243**	**531,269**	**20,987,699**
December 31, 2018					
Cash and cash equivalents	-	-	9,112,312	-	9,112,312
Restricted cash	-	-	108,915	-	108,915
Short-term investments	20,534	202,195	2,470	-	225,199
Other investments	-	80,171	-	-	80,171
Long-term investments	-	15,991	1,530	532,370	549,891
Trade receivables	-	-	3,231,106	-	3,231,106
Due from the Government	-	-	4,758,409	-	4,758,409
Other receivables	-	-	883,490	-	883,490
Other non-current assets	-	-	1,149,976	-	1,149,976
Total Financial Assets	**20,534**	**298,357**	**19,248,208**	**532,370**	**20,099,469**
December 31, 2017					
Cash and cash equivalents	-	-	6,409,827	-	6,409,827
Restricted cash	-	-	119,671	-	119,671
Short-term investments	24,898	208,894	15,490	-	249,282
Other investments	-	27,328	-	-	27,328
Long-term investments	-	16,034	1,523	533,309	550,866
Trade receivables	-	-	2,675,643	-	2,675,643
Due from the Government	-	-	2,155,739	-	2,155,739
Other receivables	-	-	875,514	-	875,514
Other non-current assets	-	-	1,292,628	-	1,292,628
Total Financial Assets	**24,898**	**252,256**	**13,546,035**	**533,309**	**14,356,498**

47. FINANCIAL ASSETS AND LIABILITIES (continued)

The following tables from to the Group's financial assets and liabilities by category: (continued)

	Financial Assets				
	Fair value through profit or loss	Available for sale	Loan and receivable	Held to maturity	Total
December 31, 2016					
Cash and cash equivalents	-	-	6,721,568	-	6,721,568
Restricted cash	-	-	122,697	-	122,697
Short-term investments	18,008	111,467	1,345	-	130,820
Other investments	-	43,190	-	-	43,190
Long-term investments	-	107,649	1,517	534,834	644,000
Trade receivables	-	-	2,864,720	-	2,864,720
Due from the Government	-	-	1,792,457	-	1,792,457
Other receivables	-	-	892,637	-	892,637
Other non-current assets	-	-	943,178	-	943,178
Total Financial Assets	**18,008**	**262,306**	**13,340,119**	**534,834**	**14,155,267**

	Other Financial Liabilities			
	September 30, 2019	December 31, 2018	2017	2016
Short-term loans	(1,918,286)	(4,347,035)	(452,879)	(230,293)
Trade payables	(3,453,638)	(3,676,558)	(3,949,398)	(3,409,205)
Due to the Government	(2,339,357)	(2,002,825)	(1,831,245)	(1,685,118)
Accrued expenses	(2,142,038)	(1,902,515)	(1,759,885)	(1,473,189)
Long-term liabilities	(2,037,050)	(2,225,877)	(2,475,726)	(3,439,109)
Other payables	(433,116)	(407,196)	(467,742)	(269,731)
Bonds payable	(12,614,222)	(11,094,096)	(10,385,873)	(9,772,656)
Other non-current payables	(101,239)	(149,428)	(69,812)	(56,431)
Total Financial Liabilities	**(25,038,946)**	**(25,805,530)**	**(21,392,560)**	**(20,335,732)**

The Company

The Company entered into a foreign exchannge and derivative agreement with BNI, Mandiri and BRI in order to hedge againts exchange rate risks. The notional amount for the nine-month period ended September 30, 2019 and the years ended December 31, 2018, 2017, and 2016 were US$125,000, US$570,000, US$355,000, and US$102,050, respectively.

The fair value of these financial liabilities is estimated using appropriate valuation techniques with inputs that are not based on observable market data.

The Company hedges the changes in the fair value of its liabilty due to risks of the foreign exchange rate fluctuations between Indonesian rupiah and US dollar. The net changes in the fair values of the above derivatives instruments for the nine-month period ended September 30, 2019 and the years ended December 31, 2018, 2017, and 2016 were US$267, US$3,044, US$847, and US$155, respectively.

Subsidiaries

PGN entered into a cross currency swap contract with ABN AMRO Bank N.V. This contract ended on March 15, 2019. The notional amount for the years ended December 31, 2018, 2017, and 2016 were US$175,843, US$144,033, and US$139,178, respectively.

Fair value of this financial liabilities is estimated using appropriate valuation techniques with inputs that are not based on observable market data.

PGN hedges the changes in the fair value of its liability due to risk of the foreign exchange rate fluctuation of Japanese yen and US dollar. The net changes in the fair values of the above derivatives instruments for the the years ended December 31, 2018, 2017, and 2016 were US$1,936, US$1,867, and US$2,129, respectively.

These transaction do not meet the hedge accounting criteria according to Indonesian Financial Accounting Standard.

47. FINANCIAL ASSETS AND LIABILITIES (continued)

b. Offsetting financial assets and liabilities

The following financial instruments are subject to offsetting, enforceable master netting arrangements and similar agreement:

	Gross amount of recognized financial assets	Gross amount of recognized financial assets set off in the statement of financial position	Net amount of financial assets presented in the statement of financial position	Related amounts not set off in the statement of financial position		Net amount
				Financial instruments	Cash collateral received	
September 30, 2019 (unaudited)						
Financial Asset						
- Trade receivable	3,846,195	(103,118)	3,743,077	-	-	3,743,077
Financial Liabilities						
- Trade payable	3,556,756	(103,118)	3,453,638	-	-	3,453,638
December 31, 2018						
Financial Asset						
- Trade receivable	3,327,292	(96,186)	3,231,106	-	-	3,231,106
Financial Liabilities						
- Trade payable	3,772,744	(96,186)	3,676,558	-	-	3,676,558
December 31, 2017						
Financial Asset						
- Trade receivable	2,736,501	(60,858)	2,675,643	-	-	2,675,643
Financial Liabilities						
- Trade payable	4,010,256	(60,858)	3,949,398	-	-	3,949,398
December 31, 2016						
Financial Asset						
- Trade receivable	2,899,983	(35,263)	2,864,720	-	-	2,864,720
Financial Liabilities						
- Trade payable	3,444,468	(35,263)	3,409,205	-	-	3,409,205

For financial assets and liabilities subject to enforceable master netting arrangements or similar arrangements above, each agreement between the Group and the counterparty allows for net settlement of the relevant financial assets and liabilities when both choose to settle on a net basis. In the absence of such an election, financial assets and liabilities will be settled on gross basis, however, each party to the master netting agreement or similar agreement will have the option to settle all such amounts on a net basis in the event of default of the other party.

48. RISK MANAGEMENT POLICY

The Group has various business activities, which expose it to various potential risks. The Group's overall risk management program focuses on minimising potential adverse effects on the financial performance of the Group.

Risk management is carried out by the Group's Board of Directors, specifically the Risk Management Committee ("the Committee"), Risk Management Unit and Risk Taking Unit to identify, assess, mitigate and monitor the risks of the Group. The Committee provides principles for overall risk management, including business risk and financial risk.

48. RISK MANAGEMENT POLICY (continued)

a. Business risks

The Group's business activities are exposed to a variety of business risks (upstream and downstream) which are as follows:

i. The Group is subject to the control of the Government and there is no guarantee that the Government will always act in the Group's best interest. The Group also derives certain benefits from being a state-owned entity, and the Group cannot guarantee that any or all of these benefits will continue.
ii. The Group is subject to audit by SKK Migas, BPK, DGT and/or the Government. The outcome of the assessment may result in claims against the Group or reduce claims against the Government that have already been recognized by the Group.
iii. The Group is dependent on joint venture partners and third party independent contractors in connection with exploration and production operations and to implement the Group's development programs.
iv. The Group's crude oil, natural gas and geothermal reserves estimates are uncertain and may prove to be inaccurate over time or may not accurately reflect actual reserves levels, or even if accurate, technical limitations may prevent the Group from retrieving these reserves.
v. The Group is dependent on management's ability to develop existing reserves, replace existing reserves and develop additional reserves.
vi. A substantial part of the Group's revenues is derived from sales of subsidised certain fuel (BBM) products by the Government.

b. Financial risk

Financial risk includes market, credit and liquidity risks.

i. Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices.

The market risk factors are as follows:

(i) Foreign exchange risk

Group revenues are determined by the movement of MOPS, which will be paid separately by the public and the Government of Indonesia in the form of subsidised fuel products and LPG products.

Regulations in Indonesia require transactions to be made in Indonesian rupiah, while most of the operating costs particularly for the procurement of crude oil and oil products are made in US dollar, which can lead to foreign exchange risks for cash and cash equivalents, trade receivables, due from the Government, trade payables, short-term loans, due to the Government and long-term liabilities.

The Group naturally mitigates foreign exchange risks through the effective management of its cash flows.

Sensitivity analysis

A strengthening (weakening) of the Indonesian rupiah against the US dollar would have increased (decreased) equity and profit or loss by the amounts shown below. This analysis is based on foreign currency exchange rate variances that were considered to be reasonably possible at the reporting date. The analysis assumes that all other variables, in particular interest rates, remain constant and excludes any impact on forecasted sales and purchases.

	Strengthening		Weakening	
	Equity	Profit or loss	Equity	Profit or loss
September 30, 2019 (unaudited)				
IDR (3% movement)	361,317	355,683	(340,270)	(334,964)
December 31, 2018				
IDR (3% movement)	364,017	358,908	(342,813)	(338,001)
December 31, 2017				
IDR (3% movement)	272,198	267,015	(256,342)	(251,461)
December 31, 2016				
IDR (7% movement)	869,047	866,557	(755,340)	(753,176)

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(ii) Comodity price risk

The volatility in prices of crude oil, natural gas and refined products and the uncertainty of market dynamics for oil and gas could adversely affect the Group's business, financial conditions and results of the Group's operations.

The Group's profitability is significantly affected by the prices of, and demand for, crude oil, natural gas and refined products, the difference between the cost price of crude oil, the costs of exploring for, developing, producing, transporting and selling crude oil, gas and refined products. The international and domestic markets for crude oil and refined products are fluctuative, and have recently been characterized by significant price fluctuations. The fluctuation of the market prices of crude oil, natural gas and refined products is subject to a variety of factors beyond the Group's control

The Group engage in derivative transaction for commodity and product prices are determined based on market prices.

The Group mitigates the risk by commodity procurement management using the Crude Oil Management System ("COMS") to acquire competitive crude prices to support production of petroleum products with the most optimum results.

The Group also participates in physical commodity contracts in the normal course of business. These contracts are not derivatives and are measured at cost. In this case, the Group is not exposed to commodity price risk because the price has been determined at the date of purchase.

(iii) Cash flow and fair value interest risk

The Group is exposed to cash flows and fair value interest rate risk due to its financial assets and liabilities position, mainly to maintain cash flows in order to meet the needs of operational and capital expenditure.

Assets and liabilities with floating rates expose the Group to cash flows interest rate risk. Financial assets and liabilities with fixed rates expose the Group to fair value interest rate risk.

The Group has established a centralised treasury and continuously monitors movements of LIBOR, SIBOR, JIBOR and other borrowing rates prevailing in the market and conducts negotiations to get the most profitable interest rates before making placement of funds or conducts negotiation with lenders if the borrowing rates become uncompetitive compared to prevailing rates in the market.

The Group may use loan facilities provided by national banks such as BNI, BRI, Bank Mandiri, as well as foreign private banks.

At the reporting date, the Group's financial assets and liabilities with floating rates, fixed rates and those that were non-interest bearing were as follows:

	September 30, 2019 (unaudited)					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	5,404,623	-	2,684,375	-	5,781	8,094,779
Restricted cash	207,339	-	32,122	-	-	239,461
Short-term investments	-	-	168,386	-	294,310	462,696
Trade receivables	-	-	-	-	3,743,077	3,743,077
Due from the Government	-	-	-	3,161,232	2,119,197	5,280,429
Other receivables	-	-	-	-	1,215,061	1,215,061
Other investments	-	-	-	-	74,126	74,126
Long-term investments	-	391,307	-	13,059	144,475	548,841
Other non-current assets	-	-	-	-	1,329,229	1,329,229
Total financial assets	**5,611,962**	**391,307**	**2,884,883**	**3,174,291**	**8,925,256**	**20,987,699**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

	September 30, 2019 (unaudited)					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Liabilities						
Short-term loans	(1,918,286)	-	-	-	-	(1,918,286)
Trade payables	-	-	-	-	(3,453,638)	(3,453,638)
Due to the Government	-	-	(15,459)	(818,690)	(1,505,208)	(2,339,357)
Accrued expenses	-	-	-	-	(2,142,038)	(2,142,038)
Other payables	-	-	-	-	(433,116)	(433,116)
Long-term liabilities	(488,313)	(1,391,538)	(41,208)	(115,991)	-	(2,037,050)
Bonds payable	-	-	-	(12,614,222)	-	(12,614,222)
Other non-current payables	-	(25,478)	-	-	(75,761)	(101,239)
Total financial liabilities	**(2,406,599)**	**(1,417,016)**	**(56,667)**	**(13,548,903)**	**(7,609,761)**	**(25,038,946)**

	December 31, 2018					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	5,045,495	-	4,062,697	-	4,120	9,112,312
Restricted cash	21,344	-	87,571	-	-	108,915
Short-term investments	677	-	132,430	-	92,092	225,199
Trade receivables	-	-	-	-	3,231,106	3,231,106
Due from the Government	-	-	-	-	4,758,409	4,758,409
Other receivables	-	-	-	-	883,490	883,490
Other investments	-	-	-	-	80,171	80,171
Long-term investments	-	391,307	-	14,989	143,595	549,891
Other non-current assets	-	-	-	-	1,149,976	1,149,976
Total financial assets	**5,067,516**	**391,307**	**4,282,698**	**14,989**	**10,342,959**	**20,099,469**
Liabilities						
Short-term loans	(4,347,035)	-	-	-	-	(4,347,035)
Trade payables	-	-	-	-	(3,676,558)	(3,676,558)
Due to the Government	-	-	(25,247)	(795,082)	(1,182,496)	(2,002,825)
Accrued expenses	-	-	-	-	(1,902,515)	(1,902,515)
Other payables	-	-	-	-	(407,196)	(407,196)
Long-term liabilities	(361,855)	(1,703,996)	(58,722)	(101,304)	-	(2,225,877)
Bonds payable	-	-	-	(11,094,096)	-	(11,094,096)
Other non-current payables	-	-	-	-	(149,428)	(149,428)
Total financial liabilities	**(4,708,890)**	**(1,703,996)**	**(83,969)**	**(11,990,482)**	**(7,318,193)**	**(25,805,530)**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

	December 31, 2017					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	2,770,228	-	3,631,425	-	8,174	6,409,827
Restricted cash	75,243	-	44,428	-	-	119,671
Short-term investments	755	-	150,699	-	97,828	249,282
Trade receivables	-	-	-	-	2,675,643	2,675,643
Due from the Government	-	-	-	-	2,155,739	2,155,739
Other receivables	-	-	-	-	875,514	875,514
Other investments	-	-	-	-	27,328	27,328
Long-term investments	-	391,307	-	20,268	139,291	550,866
Other non-current assets	-	-	-	-	1,292,628	1,292,628
Total financial assets	**2,846,226**	**391,307**	**3,826,552**	**20,268**	**7,272,145**	**14,356,498**
Liabilities						
Short-term loans	(452,879)	-	-	-	-	(452,879)
Trade payables	-	-	-	-	(3,949,398)	(3,949,398)
Due to the Government	-	-	(24,680)	(780,626)	(1,025,939)	(1,831,245)
Accrued expenses	-	-	-	-	(1,759,885)	(1,759,885)
Other payables	-	-	-	-	(467,742)	(467,742)
Long-term liabilities	(315,951)	(1,952,671)	(50,008)	(157,096)	-	(2,475,726)
Bonds payable	-	-	-	(10,385,873)	-	(10,385,873)
Other non-current payables	-	(5,083)	-	-	(64,729)	(69,812)
Total financial liabilities	**(768,830)**	**(1,957,754)**	**(74,688)**	**(11,323,595)**	**(7,267,693)**	**(21,392,560)**

	December 31, 2016					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	3,011,880	-	3,703,712	-	5,976	6,721,568
Restricted cash	79,537	-	43,160	-	-	122,697
Short-term investments	-	-	70,322	-	60,498	130,820
Trade receivables	-	-	-	-	2,864,720	2,864,720
Due from the Government	-	-	-	-	1,792,457	1,792,457
Other receivables	-	-	-	-	892,637	892,637
Other investments	-	-	-	-	43,190	43,190
Long-term investments	-	391,307	-	21,960	230,733	644,000
Other non-current assets	-	-	-	-	943,178	943,178
Total financial assets	**3,091,417**	**391,307**	**3,817,194**	**21,960**	**6,833,389**	**14,155,267**
Liabilities						
Short-term loans	(230,293)	-	-	-	-	(230,293)
Trade payables	-	-	-	-	(3,409,205)	(3,409,205)
Due to the Government	-	-	(23,538)	(732,573)	(929,007)	(1,685,118)
Accrued expenses	-	-	-	-	(1,473,189)	(1,473,189)
Other payables	-	-	-	-	(269,731)	(269,731)
Long-term liabilities	(671,638)	(2,554,986)	(50,562)	(161,923)	-	(3,439,109)
Bonds payable	-	-	-	(9,772,656)	-	(9,772,656)
Other non-current payables	-	(8,829)	-	-	(47,602)	(56,431)
Total financial liabilities	**(901,931)**	**(2,563,815)**	**(74,100)**	**(10,667,152)**	**(6,128,734)**	**(20,335,732)**

A change of 20 basis points in floating interest rates at the reporting date would have affected income before tax by the amounts shown below. This analysis assumed that all other variables, in particular foreign currency rates, remain constant.

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

Effect in:	+20 bp increase	-20 bp decrease
Income before tax	4,410	(4,410)
Cash flows sensitivity - net	**4,410**	**(4,410)**

ii. Credit risk

The Group has significant credit risk from unpaid receivables, cash and cash equivalents and investments in debt securities. In most transactions, the Group uses banks and financial institutions that are independently assessed with a rating of AAA, AA+, AA, AA- and A+, A, and A-.

For the Group's credit sales, the Group applied a standard operating procedure for credit approval mechanism. With such practice, some portion of the Group's credit sales has been secured with a collateral/bank guarantee. For other credit sales without collateral/bank guarantee, the Group ensured that credit scoring, credit limit evaluation and credit approval were performed and provided prior to any sales to the customer.

The Group also has a Credit Management System to monitor the usage of credit limits and automatic blocking facility in the case of no payment starting from seven days after the maturity date. The Group will impose penalty for overdue payments in some sales contracts based on the result of each customer's credit evaluation.

(i) Third parties and related parties

Financial assets neither past due nor impaired

The credit quality of the Group's financial assets that are neither past due nor impaired, was assessed by referencing external credit ratings PT Pemeringkat Efek Indonesia ("Pefindo") or to historical information about counterparty default risk rates, as follows:

	As of September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Cash and cash equivalents				
Rated				
Rating AAA	6,702,123	7,285,583	5,654,815	6,179,970
Rating AA+	704,614	1,139,349	426,347	313,456
Rating AA	50,835	50,028	26,770	7,613
Rating AA-	1,618	3,528	2,581	35,090
Rating A+	-	1,381	31,699	14,714
Rating A	4,709	20,380	147,282	78,117
Rating A-	19,721	21,472	-	-
Not rated	611,159	590,591	120,333	92,608
Total	**8,094,779**	**9,112,312**	**6,409,827**	**6,721,568**
Restricted cash				
Rated				
Rating AAA	190,272	104,230	107,688	114,855
Rating A+	-	-	5	7,615
Rating A	-	-	224	227
Rating A-	462	462	-	-
Not rated	48,727	4,223	11,754	-
Total	**239,461**	**108,915**	**119,671**	**122,697**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets neither past due nor impaired (continued)

The credit quality of the Group's financial assets that are neither past due nor impaired, was assessed by referencing external credit ratings PT Pemeringkat Efek Indonesia ("Pefindo") or to historical information about counterparty default risk rates, as follows: (continued)

	As of September 30, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Short-term investments				
Rated				
Rating AAA	75,598	25,332	19,022	22,358
Rating AA+	6,833	1,027	1,145	1,799
Rating AA	3,575	4,109	10,108	11,669
Rating AA-	2,841	3,129	3,085	4,964
Rating A+	3,470	-	-	-
Rating A	5,691	5,357	3,522	-
Rating A-	2,709	2,330	749	-
Rating BB+	-	-	-	5,195
Rating BBB+	-	-	1,870	1,635
Rating BBB	3,887	3,887	-	-
Rating BBB-	-	41,948	44,149	34,816
Not rated	358,092	138,080	165,632	48,384
Total	**462,696**	**225,199**	**249,282**	**130,820**
Long-term investments				
Rated				
Rating AAA	545	2,597	7,198	8,873
Rating AA	6,011	5,897	6,320	8,847
Rating BBB-	4,950	4,950	4,950	-
Rating BB+	-	-	-	2,000
Not rated	741	552	221	186
Total	**12,247**	**13,996**	**18,689**	**19,906**
Trade receivables				
Third parties				
> US$10,000 - Good credit history	1,352,947	1,335,703	945,008	850,886
< US$10,000	810	362	726	9,909
Related parties	996,270	675,922	251,453	394,209
Total	**2,350,027**	**2,011,987**	**1,197,187**	**1,255,004**
Other receivables				
Third parties				
> US$10,000 - good credit histories	882,565	661,979	570,683	582,970
< US$10,000	36	31	82	130
Related parties	214,280	148,777	253,389	236,205
Total	**1,096,881**	**810,787**	**824,154**	**819,305**
Other assets				
Third parties	96,201	80,287	80,349	135,481
Related parties	26,725	54,228	152,791	82,166
Total	**122,926**	**134,515**	**233,140**	**217,647**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets that are past due but not impaired

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables				
- Less than 3 months	425,477	431,868	227,439	365,007
- 3 - 6 months	58,850	61,194	212,778	30,820
- 6 - 12 months	34,138	21,138	10,231	34,955
- 12 - 24 months	15,590	11,040	1,201	36,788
- > 24 months	6,932	11,561	2,194	2,499
Total	**540,987**	**536,801**	**453,843**	**470,069**
Other receivables				
Third parties				
- Less than 3 months	65,393	42,912	31,832	3,904
- 3 - 6 months	426	1,699	642	27,182
- 6 - 12 months	490	872	160	3,947
- 12 - 24 months	1,499	10,674	524	6,695
- > 24 months	5,736	5,476	921	3,669
Total	**73,544**	**61,633**	**34,079**	**45,397**
Related parties				
- Less than 3 months	97	9	141	391
- 3 - 6 months	3,359	7	2	-
- 6 - 12 months	68	49	1,332	24
- 12 - 24 months	26	15	68	-
- > 24 months	39	24	11	6,215
Total	**3,589**	**104**	**1,554**	**6,630**
Other assets				
Third parties	-	-	90,995	-
Related parties	11,014	10,679	-	4,066
Total	**11,014**	**10,679**	**90,995**	**4,066**

Trade receivables

Trade receivables from third parties and related parties that are past due but not impaired at the reporting date relate to customers who have not had defaults in the past two years. Some of the trade receivables from these customers have also been secured with collateral/bank guarantee.

Financial assets that are impaired

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables				
- Current (not overdue)	422,653	453,510	731,355	345,402
- Less than 3 months	150,753	182,954	179,382	422,487
- 3 - 6 months	13,697	70,803	81,009	41,370
- 6 - 12 months	271,500	10,541	26,250	8,647
- 12 - 24 months	89,756	45,159	69,412	466,339
- > 24 months	167,366	180,082	195,558	165,566
	1,115,725	943,049	1,282,966	1,449,811
Impairment	(263,662)	(260,731)	(258,353)	(310,164)
Net	**852,063**	**682,318**	**1,024,613**	**1,139,647**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets that are impaired (continued)

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
Other receivables				
Related parties				
- Less than 3 months	94	-	110	31
- 3 - 6 months	-	-	31	3
- 6 - 12 months	3	297	1	-
- 12 - 24 months	3	-	1	-
- > 24 months	1,421	1,426	1,434	1,403
	1,521	**1,723**	**1,577**	**1,437**
Third parties				
- Less than 3 months	23,431	6,169	5,651	13,383
- 3 - 6 months	189	673	4,613	751
- 6 - 12 months	872	975	6,734	2,163
- 12 - 24 months	2,954	8,362	4,112	8,048
- > 24 months	31,776	12,631	13,057	8,591
	59,222	**28,810**	**34,167**	**32,936**
	60,743	30,533	35,744	34,373
Impairment	(19,696)	(19,567)	(20,017)	(13,068)
Net	**41,047**	**10,966**	**15,727**	**21,305**
Other assets				
Related parties				
- 12 - 24 months	-	-	-	-
- > 24 months	18,569	18,190	19,394	19,550
Third parties				
- Current (not overdue)	1,580	-	-	-
- 12 - 24 months	-	9,165	-	1,469
- > 24 months	-	-	17,023	20,707
	20,149	27,355	36,417	41,726
Impairment	(20,149)	(27,355)	(36,417)	(41,726)
Net	**-**	**-**	**-**	**-**

Trade receivables

Trade accounts receivable from third parties and related parties as of September 30, 2019 amounting to US$3,743,077 have been impaired amounting to US$263,662, with the largest trade receivables from Government institutions and MoSOE, which is TNI/Ministry of Defence amounting to US$432,010.

Other receivables

Other receivables from third parties and related parties as of September 30, 2019 amounting to US$1,215,061 have been impaired by US$19,696.

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(ii) Government

Financial assets neither past due not impaired

	As of September 30, 2019 (unaudited)	December 31, 2018	2017	2016
The Company				
Receivables on revenue recognition from Disparity of Selling Price	3,160,867	2,924,148	-	-
Receivable of reimbursements of Subsidy costs for LPG 3 kg cylinders	870,151	1,147,538	1,404,911	1,068,920
Receivable of subsidy reimbursements for certain fuel (BBM) products	781,349	175,556	473,928	422,398
Receivables for marketing fees	90,024	72,489	49,902	-
Receivables from kerosene subsidies reimbursement	17,192	16,828	-	-
Kerosene conversion	10,820	10,626	-	-
Other receivables	-	-	102	14
Sub total	**4,930,403**	**4,347,185**	**1,928,843**	**1,491,332**
Subsidiaries:				
PEP				
- DMO fees	91,190	106,398	90,930	77,340
- Underlifting	10,354	18,942	-	-
PHE				
- DMO fees	20,089	15,414	25,859	25,613
- Underlifting	17,420	25,730	46,480	31,395
PEPC				
- Underlifting	188,117	224,904	174,563	79,966
PHI				
- DMO Fees	20,885	18,780	-	-
- Underlifting	1,971	1,056	-	-
Sub total	**350,026**	**411,224**	**337,832**	**214,314**
Total	**5,280,429**	**4,758,409**	**2,266,675**	**1,705,646**
Financial assets that are impaired				
The Company				
Receivables for marketing fees	-	-	-	86,811
Provision for impairment	-	-	(110,936)	-
	-	-	(110,936)	86,811
Total consolidated	**5,280,429**	**4,758,409**	**2,155,739**	**1,792,457**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

iii. Liquidity risk

The amount of liquidity which the Group requires for its operations is uncertain and its operations may be adversely affected if the Group does not have sufficient working capital to meet its cash and operational requirements. This may occur as a result of, amongst other reasons, delays in the payment of the Government's subsidies.

The Group uses significant amounts of cash in its operations, especially to procure commodities and raw materials. In particular, one of its principal operating costs is the acquisition of feedstock for its refineries. Fluctuations in market prices for crude oil, natural gas and their refined products and fluctuations in exchange rates cause working capital and costs for the Group's upstream and downstream operations to be uncertain.

The Group funds its operations principally through cash flows from operations, a significant portion of which comprises sales, subsidy payments, working capital facilities (including bank overdrafts, L/C and revolving credit), and long-term bank loans. In accordance with the terms of PSO's assignment, the Group is required to submit its claims for subsidy to the Government at the end of each month for the subsidised fuel distributed in that month.

As of September 30, 2019, and December 31, 2018, 2017, and 2016 the Group has cash and cash equivalents in the amount of US$8,094,779, US$9,112,312, US$6,409,827, and US$6,721,568, respectively (Note 6). The Group manages liquidity risk by continuously monitoring forecasts and actual cash flows and matching the maturity profiles of trade receivables and trade payables.

The table below summarizes the maturity profile of the Group's financial liabilities based on cash flow on contractual undiscounted payments:

	Less than 1 year	Later than 1 year and not later than 5 years	Later than 5 years	Total
September 30, 2019 (unaudited)				
Financial liabilities				
Short-term loans	1,918,286	-	-	1,918,286
Trade payables	3,453,637	-	-	3,453,637
Due to the Government	1,544,685	317,548	641,314	2,503,547
Accrued expenses	2,142,038	-	-	2,142,038
Other payables	1,426,451	-	-	1,426,451
Long-term liabilities	458,638	1,360,833	282,469	2,101,940
Bonds payable	549,659	7,632,966	13,569,091	21,751,716
Other non-current payables	-	91,524	39,600	131,124
Total financial liabilities	**11,493,394**	**9,402,871**	**14,532,474**	**35,428,739**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

iii. Liquidity risk (continued)

	Less than 1 year	Later than 1 year and not later than 5 years	Later than 5 years	Total
December 31, 2018				
Financial liabilities				
Short-term loans	4,347,035	-	-	4,347,035
Trade payables	3,676,558	-	-	3,676,558
Due to the Government	1,211,056	262,428	531,845	2,005,329
Accrued expenses	1,902,515	-	-	1,902,515
Other payables	1,257,437	-	-	1,257,437
Long-term liabilities	456,506	1,530,224	343,001	2,329,731
Bonds payable	611,409	5,886,768	14,088,112	20,586,289
Other non-current payables	-	120,591	58,314	178,905
Total financial liabilities	**13,462,516**	**7,800,011**	**15,021,272**	**36,283,799**
December 31, 2017				
Financial liabilities				
Short-term loans	452,879	-	-	452,879
Trade payables	3,949,398	-	-	3,949,398
Due to the Government	1,138,463	255,460	437,644	1,831,567
Accrued expenses	1,759,885	-	-	1,759,885
Other payables	1,178,119	-	-	1,178,119
Long-term liabilities	394,188	1,293,419	844,763	2,532,370
Bonds payable	575,969	4,625,314	14,773,197	19,974,480
Other non-current payables	-	84,373	-	84,373
Total financial liabilities	**9,448,901**	**6,258,566**	**16,055,604**	**31,763,071**
December 31, 2016				
Financial liabilities				
Short-term loans	230,293	-	-	230,293
Trade payables	3,409,205	-	-	3,409,205
Due to the Government	1,194,559	5,886	488,804	1,689,249
Accrued expenses	1,473,189	-	-	1,473,189
Other payables	1,077,755	-	-	1,077,755
Long-term liabilities	887,736	2,144,421	585,919	3,618,076
Bonds payable	490,969	3,235,755	15,643,533	19,370,257
Other non-current payables	-	62,903	-	62,903
Total financial liabilities	**8,763,706**	**5,448,965**	**16,718,256**	**30,930,927**

c. Capital Management

The Directors' policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. Capital consists of share capital, retained earnings, non-controlling interests and other equity components. The Board of Directors ensures the return on capital as well as the level of dividends.

The Group as an entity whose main business involves oil and gas monitors capital on the basis of the debt-to-equity ratio. Net debt is calculated as total interest bearing borrowings including short-term and long-term, while total capital is calculated from equity in the statement of consolidated statement of financial position. Weighted average interest expense on interest-bearing borrowings (excluding liabilities with imputed interest) for September 30, 2019 and December 31, 2018, 2017, and 2016 were 5.32%, and 5.17%, 4.92% dan 4.68%.

48. RISK MANAGEMENT POLICY (continued)

c. Capital Management (continued)

The Group's debt to equity ratio at the reporting date is as follows:

	September 30, 2019 (unaudited)	December 31,		
		2018	2017	2016
Total liabilities (interest bearing)	17,429,185	18,487,337	13,707,878	13,775,548
Total equity attributable to owners of the parent entity	27,387,881	27,598,721	25,124,718	23,665,987
Debt-to-equity ratio	63.64%	66.99%	54.56%	58.21%
Total own capital to total assets ratio	41.78%	40.31%	37.85%	36.82%
Return-on-equity ratio	2.74%	10.08%	12.62%	17.74%

d. Fair value

The following are the Group's financial assets that were measured at fair value as of September 30, 2019 (unaudited):

	Level 1	Level 2	Level 3	Total
Financial assets				
Short-term investments	401,094	60,896	706	462,696
Other investments	-	-	74,126	74,126
Total financial assets	**401,094**	**60,896**	**74,832**	**536,822**

As of September 30, 2019, there were no transfers of fair value measurement between level 1, level 2 and level 3.

The table below shows the carrying amounts and fair values of long-term financial liabilities as of September 30, 2019, and December 31, 2018, 2017, and 2016:

	September 30, 2019 (unaudited)	
	Carrying Amount	Fair Value
Long-term liabilities (Note 20)	2,037,050	2,084,218
Bonds payable (Note 21)	12,614,222	14,173,960
Total financial assets	**14,651,272**	**16,258,178**

	December 31,					
	Carrying Amount			Fair Value		
	2018	2017	2016	2018	2017	2016
Long-term liabilities (Note 20)	2,225,877	2,475,726	3,439,109	2,329,464	2,478,169	3,653,966
Bonds payable (Note 21)	11,094,096	10,385,873	9,772,656	11,101,427	11,504,854	9,849,462
Total financial assets	**13,319,973**	**12,861,599**	**13,211,765**	**13,430,891**	**13,983,023**	**13,503,428**

The fair value of long-term liabilities is measured using the discounted cash flows based on the interest rate on the latest long-term liabilities of the Group. The fair value of bonds payable is determined by reference to market price at the reporting date.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES

a. Cooperation Contract commitment

In accordance with the Cooperation Contract, PT Pertamina EP shall relinquish minimum of 10% of the original contract area to the Government on or before the end of the tenth year from the effective date of the Cooperation Contract. On July 18, 2013, PT Pertamina EP relinquished 18.02% of initial working area to the Government.

PT Pertamina EP is required to pay a bonus to the Government amounting to US$1,500 in 30 days after cumulative production of oil and gas reaches 1,500 MMBOE from the effective date of the Cooperation Contract. PT Pertamina EP's cumulative production of oil and gas up to September 30, 2019 has not yet reached 1,500 MMBOE.

On September 30, 2019, PT Pertamina Hulu Energi had 12 exploration drilling commitments in relation to contractual PSC with commitments amount between US$11,750 to US$225,000 and 11 exploration drilling commitments in relation to the Gross Split PSC with commitment amounts between US$15,550 to US$239,300.

PT Pertamina Hulu Indonesia has expenditure commitments and work plans with a commitment value between US$141,300 to US$703,000 for a period of six years from the effective date of the contract.

b. Capital commitments

The Group has capital expenditure commitments in the normal course of business. As of September 30, 2019, the Group's unrealized total outstanding capital expenditure commitments amounting to US$2,171,804.

c. Operating lease commitments - Group as lessee

Non-cancellable operating lease payments are as follows:

	For the nine-month periods ended September 30,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Less than one year	456,502	423,063	493,867	465,882	375,333
Between one to five years	480,211	518,505	559,313	571,611	525,309
More than five years	46,567	36,945	33,284	24,160	-
Total	**983,280**	**978,513**	**1,086,464**	**1,061,653**	**900,642**

The Group leases a number of vessels, office buildings, vehicles and IT facilities under operating leases. The leases typically run for a period of ten years, with an option to renew the lease.

Operating lease expense for nine-months periods ended September 30, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016, was US$648,508 (unaudited), US$435,229 (unaudited), US$343,868, US$782,362 and US$796,897 respectively.

d. Gas sale and purchase agreement

As of September 30, 2019, the Company through PT Pertamina EP has commitments to deliver gas totaling 911.882 MMSCF to various customers. The gas will be periodically delivered from 2019 until 2029.

As of September 30, 2019, the Company, through PHE, has various significant gas supply agreements with various customers, with gas volumes of each contract between 0.8 TBTU to 1.418 TBTU. The expiration of these agreements ranges from 2019 until 2031.

As of September 30, 2019, the Company, through PHI, has significant gas sale and purchase agreement contracts with gas volumes from 0.8 TBTU to 183.13 TBTU. These contracts will expire in 2019 to 2022.

As of September 30, 2019, the Company, through PGN has 35 Gas Sales and Purchase Agreements ("GSA") with contract periods of 10 - 30 years. These contracts will expire from 2019 to 2037.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

d. Gas sale and purchase agreement (continued)

Based on Indonesian Presidential Regulation No. 40 year 2016 on Natural Gas Pricing and Regulation of the Minister of Energy and Mineral Resources of the Republic of Indonesia No. 40 year 2016 on Natural Gas Price for Specific Industries, the Company amended contracted gas prices in its gas sales agreements with the particular industry effective January 30, 2017.

e. LNG long-term purchase contract commitment

The Company entered into a LNG Long Term Purchase Contract with several sellers for LNG trading business, with minimum purchase quantity per annum of each contract between 0.1 million MT to 1.5 million MT, with purchase price that linked to the related market price at the time of delivery of LNG. The expiry of those contracts ranges from 2019 until 2044.

f. Transfer of 10% participating interest (“PI”) to the regional government (“BUMD”)

On December 19, 2017, PHE ONWJ and MUJ ONWJ signed a 10% PI transfer agreement at ONWJ PSC Block from PHE ONWJ to MUJ ONWJ. The agreement is effective on the date of receipt of approval from the Minister of Energy and Mineral Resources or on the date stipulated by MoEMR in his approval letter.

On May 17, 2018, the approval 10% of PI transfer in the ONWJ working area has been approved by the Minister of Energy and Mineral Resources through a Letter from the Minister of Energy and Mineral Resources to the Head of SKK Migas No. 2803/13/MEM.M/2018. Stated in the letter, the date of the transfer of PHE ONWJ to MUJ ONWJ is from the effective date of the Block ONWJ PSC.

On December 17, 2018, the PI transfer value was determined through a Letter from the Minister of Energy and Mineral Resources to the Head of SKK Migas No. 3149/12/MEM.M/2018. The transfer value is calculated from the BUMD's liability for the portion of the implementation guarantee (Performance Bond) for the implementation of a definite work commitment and the portion of the unrecovered cost payment by the new KKS Contractor to the old KKS Contractor with a value of US$43,292.

On September 19, 2018, PHM and PT Migas Mandiri Pratama Kutai Mahakam ("MMPKM") signed the Principal Agreements of the 10% Transfer Plan Participating Interest in the Mahakam Working Area, where the parties will hold more intensive discussions regarding the terms and conditions.

On July 17, 2019, PHM and MMPKM signed the 10% Transfer and Management Agreement on Interest Participation in Production Sharing Contracts in the Mahakam Working Area, which regulates compensation, financing mechanisms, returns and production sharing.

On September 12, 2019 transfer of 10% PI in the Mahakam working area was approved by the Minister of Energy and Mineral Resources through a Letter from the Minister of Energy and Mineral Resources to the Head of SKK Migas No. 371/13/MEM.M/2019. It is stated in the letter that the date of the transfer of PHM to MMPKM is from the effective date of the Mahakam Block KBH.

Starting from the date of transfer, production sharing payments that are part of MMPKM will be made by PHM every month, after deducting MMPKM's portion of KBH Mahakam's operating costs and other obligations in accordance with KBH. In the event that the share of MMPKM production in the current month does not meet the share of operating costs that must be paid by MMPKM, the underpayment of operating costs will be calculated in the following months.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

f. Transfer of 10% participating interest ("PI") to the regional government ("BUMD") (continued)

To guarantee MMPKM revenues, the production share and operating costs of the MMPKM portion are calculated using a provisional percentage for the full year. If the accumulated operating costs that must be paid by MMPKM to PHM in one year exceeds the MMPKMM portion of the production share, PHM will provide an MMPKM payment of 1 US dollar (full amount) each month in the following year.

On August 7, 2018, PHE Siak and PT Riau Petroleum Siak agreed to sign the transfer and management agreement 10% of PI in accordance with Minister of Energy and Mineral Resources Regulation No. 37 of 2016 concerning Provisions on the 10% of PI Offer in the Oil and Gas Block. As of the date of this financial statements, the transfer has not been completed.

g. Lease of State Owned Property ("BMN")

The Minister of Finance Decree No. 92/KMK.06/2008 dated May 2, 2008 stipulates that the status of the assets previously owned by the former Pertamina Entity, which were not recognized in the opening balance sheet of Pertamina in accordance with the Minister of Finance Decree No. 23/KMK.06/2008, are State Owned Property ("BMN") for which the management of the assets is done by the Directorate General of State Assets ("DJKN").

On December 12, 2014, the Minister of Finance issued letter No. S-837/MK.06/2014 to SKK Migas which stated that the BMN lease is to be treated as refundable operating costs. As a follow up to the Minister of Finance's Letter, the Head of SKK Migas issued Letter No.SRT-1294/SKKO0000/2014/S4 dated December 30, 2014 states that basically SKK Migas can approve the imposition of BMN leases as an operating cost (cost recovery) as long as these assets are used in the Company's upstream oil and gas operations. Based on the result of BMN verification which have been reported to the Minister of Finance through the Letter of President Director of PT Pertamina (Persero) No.194/C00000/2011-S0 dated March 29, 2011, SKK Migas had opinion that the basis for leasing should be Rp6,630,929 million (revaluation value), which categorized equipment, buildings and other assets currently used by the Company.

Management believes that the contractual agreement relating to the BMN used must be recorded as a finance lease.

On September 20, 2016, the State Property Lease Agreement was signed between the Ministry of Finance of the Republic of Indonesia and PT Pertamina EP No.PRJ-3-MK.6/2016 and No.1307/EP0000/2016-S0 ("Agreement") with a basis of imposition of BMN Lease of Rp6,630,929 million.

Based on the agreement, the Ministry of Finance of the Republic of Indonesia will not charge the lease fee for BMN not used by PT Pertamina EP since the BMN is not included in the scope of the Agreement.

The oil and gas assets of the former ONWJ PSC and DJKN which are currently owned by the DJKN are used by the ONWJ Gross Split PSC contractors based on lease scheme.

On January 16, 2018, PT PHE ONWJ and DJKN signed a Lease Agreement No. PRJ-1/KN/2018 for the lease period from January 19, 2017 to January 19, 2018 with lease cost of Rp225,603,000,000 (full amount). The lease period can be extended based on written request from PHE ONWJ to DJKN through SKK Migas.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

g. Lease of State Owned Property ("BMN") (continued)

On April 17, 2018 Lease Agreement no. PRJ-2/KN/2018 was signed by PT PHE ONWJ and DJKN for the lease period from January 19, 2018 to January 18, 2019 with a lease charge of Rp202,650,750,000 (full amount).

For the future lease periods, the method of asset leases calculation will refer to Regulation of the Minister of Finance (PMK) No. 89/PMK.06/2019.

h. Lease, Operation and Maintenance Agreement

- On January 25, 2012, PGN and Hoegh Lampung signed a lease, operation and maintenance agreement that is valid from the delivery date until 20 years after the delivery date.

  On February 21, 2014, PT PGN LNG Indonesia ("PLI"), PGN and Hoegh Lampung signed a Novation Agreement on Amended and Restated Leases and Operations and Maintenance Agreements where PGN rights and obligations related to the above agreement were transferred to PLI. Through the novation agreement, Hoegh Lampung will provide the Lampung Floating Storage Regasification Terminal ("FSRT") and perform regasification process for 20 years with an option to extend for two periods of 5 years each.

- On September 14, 2015, PT Kalimantan Jawa Gas ("KJG"), PLN, SEM, PT Bakrie & Brothers, Tbk. and PC Muriah Ltd. ("PCML") signed the Letter Agreement on the Application of Novation and Amendment of Gas Transportation Agreement ("GTA Kalija I") with KJG as Transporter, PLN as Offtaker, and PCML as Shipper. Based on the terms of the Gas Transportation Agreement, the Transporter agreed to provide gas transportation services from the Kepodang field to PLN's power plant facilities in Tambak Lorok.

  The agreement is valid for 12 years from the start from the date of gas delivery. On June 8, 2017, PCML gave a notification regarding the force majeure regarding the Kepodang-Tambak Lorok Gas Transport Agreement.

i. Legal Case

Class action in enviromental issue at PHE ONWJ Block

In July 2019, PHE ONWJ experienced a "well kick" in the Java Sea near Karawang (West Java) at an offshore platform where a reactivated well is being developed. This well kick led to oil spill. The Group are implementing responsive environmental mitigation measures and undertaking recovery efforts in coordination with the government and other key stakeholders, and the Group are continuing to investigate the incident.

Some of Banten Bay and Thousand Island residents have filed a lawsuit or a class action suit against the Company and PHE ONWJ for the impact of such oil spill. They request for compensation as oil spill from YYA-1 well had impacted their lives negatively. As of the date of the financial statements, the class action has been registered at the Central Jakarta District Court. However, PHE ONWJ has not yet received a notification from the Central Jakarta District Court.

The YYA-1 well oil spill is also being investigated by Directorate of Special Crime ("Bareskrim Polri") based on an allegation of environmental pollution crime as stipulated in Law No. 32 of 2009 regarding Environmental Protection and Management. As of the date of the financial statements, the investigation proceeding is still ongoing at Bareskrim Polri which several employees from Company and/or PHE ONWJ has been summoned to give clarification.

Force majure on Transportation Gas Agreement Kepodang - Tambak Lorok declaration by PC Muriah Ltd ("PCML").

On June 8, 2017, KJG received a letter from PC Muriah Ltd regarding notification of force majeur that resulted from permanent depletion on gas reserve at Kepodang Field. KJG has responded the letter through letter dated June 13, 2017. KJG disagrees with the force majeur since based on the Gas Transportation Agreement, force majeur should be determined by independent consultant and then should be examined and approved by SKK Migas. Until the issuance date of these financial statements, the terms of force of force majeure as defined by GTA have not been fulfilled. In accordance with the GTA, there are SOP obligations that must be fulfilled by PCML, but PCML refuses to settle these obligations. After both parties cannot come up with an agreement even through discussion and mediation by BPH Migas, KJG submitted an Arbitration lawsuit to the ICC on August 29, 2018.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

i. Legal Case (continued)

PT Barkrie Harper Lawsuit

On November 20, 1996, the Company entered into a Build and Rent Agreement in the form of Development, Operation, Lease and Maintenance of Piping Kertapati-Jambi ("Pipeline Project Work") No.SPB-1474A/C000/96 with PT Bakrie Harper (formerly PT Bakrie Harper Corporation - "Bakrie"). Total Pipeline Project Work Value and Rental fee was US$144,068 and US$16,703 (excluding VAT), respectively. The lease term for such project is 10 years with commencement date of the project development on May 19, 1997.

Due to the monetary crisis in 1998, the Company delayed the Pipeline Project Work and renegotiated the project value. In 2001, both parties agreed to appoint Deloitte Touche ("Deloitte") as an independent party to audit fair market costs of the Pipeline Project Works. Based on the Deloitte audit report issued in 2001, fair market costs and rental costs were US$92,125 and US$7,616 respectively.

On August 27, 2002, the Company appointed BPKP to conduct due diligence to obtain a fair market value for the costs incurred by Bakrie for the project from commencement date until the date when the project development ceased. Based on the BPKP report released on December 23, 2003, it is noted that the physical progress of the Pipeline Project Work was 10.6853% with a fair value of US$15,394 excluding the compensation for investment costs incurred. BPKP also noted that the Pipeline Project Work was no longer economics and feasible to continue.

On June 9, 2017, both parties agreed to settle the case through the Indonesian National Arbitration Board ("BANI"). The amount claimed by Bakrie is US$15,394 for physical progress work and US$17,307 for 14 years of interest. Based on BANI decision No. 969/VIII/ARB-BANI/2017 dated February 21, 2018, it is noted that the Pipeline Project Work agreement is already expired, the physical progress of the Pipeline Project Work is 10.6853% and the Company should pay to Bakrie the amount of US$15,856, which consists of compensation and total interest to Bakrie amounting to US$15,394 and US$462, respectively.

On April 16, 2018, the Company appointed the Attorney General's Office of the Republic of Indonesia ("Jamdatun") to provide legal assistance and to propose Legal action related to BANI decision. The Company is willing to settle BANI decision with condition that the payment made by the Company is based on BPK report and should be supported by adequate documents, including land rights with value equal to the payment will be made by the Company. The cancellation claim has been submitted by Jamdatun through the Central Jakarta District Court but was refused. Based on the advice of the State Attorney, in the event that Bakrie submitted an attempt to execute the BANI verdict, the Company has the option to file a lawsuit against the execution.

j. Onerous contract

The Public Service Obligation (“PSO”) assignment to supply fuel products

The Company is assigned by the Government to engage in PSO to supply certain fuel products. The Company and the Government agreed to use Mean of Platts Singapore "MOPS") as the basis for the market price of fuel projects use to calculate the amounts of subsidies. However, the retail selling price of certain fuel products issued by the Ministry of Energy and Mineral Resources during 2017 and 2018 cannot cover all costs for procuring and distributing fuel products which resulted losses from the sale of PSO fuel products for the nine-month periods ended September 30, 2019 and 2018, and the years ended December 31, 2018, 2017 and 2016.

k. Reimbursement of investment costs for previous PSC contractors

Minister of Energy and Mineral Resources Regulation No. 26/2017, No. 47/2017, No. 24/2018 and No. 46/2018 require the new PSC contractor to reimburse certain investment costs spent by the previous PSC contractor which had not been recovered at the time the PSC expired. The amount to be reimbursed is based on verification and approval from SKK Migas. Based on Letter SRT-0665/SKKMA0000/2018/S4 dated August 13, 2018 from SKK Migas, the amount to be reimbursed by PHSS to the Sanga-Sanga PSC contractors amount to US$111.9 million. PHSS disagreed with this amount and is in the process of obtaining assistance from the relevant institution to verify the amount to be paid. As of September 30, 2019, the final total investment costs to be reimbursed to the Sanga-Sanga PSC contractor had not been determined.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

l. Mechanism of Trustee Borrowing Structure ("TBS")

On June 13, 2019, PEPC through TBS obtained the following financing facilities for the development of the JTB project with a total facility of US$1,846,400:

a. The Jambaran-Tiung Biru Loan Agreement, which was signed by the Trustee, MUFG Bank Ltd. an Agent and Lender, with a total facility of US$700,000 from Tranche A and US$1,046,400 from Tranche B. This loan bears interest at LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B

b. The Jambaran-Tiung Biru Wakala Agreement, which was signed by the Trustee and MUFG Bank (Malaysia) Berhad as an Investment Agent, with a total facility of US$40,000 from Tranche A and US$60,000 from Tranche B. This loan bears interest at LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B

The principal loan for Tranche A must be repaid every six months with the first payment due on March 31, 2022 and the final payment due on March 31, 2034. The principal loan for Tranche B must be repaid semi-annually with the first payment due on the date March 31, 2022 and final payment due on March 31, 2029.

m. RDMP project RU-V Balikpapan and Lawe Lawe project

The Company has entered into various contracts in relation to RDMP Project RU-V Balikpapan and Lawe Lawe project with outstanding total contracts amounts of US$2,594,596 and Rp25,894,796 million.

As of September 30, 2019, the Company made advance payments to vendors amounted to US$199,915 (Note 15b).

n. Provision for assets decommissioning and site restoration for PHM, PHSS, PHKT and PT Pertamina Hulu Energi OSES ("PHE OSES")

As discussed in Note 3.b.viii. the Group recognizes provision for ASR for all assets in the Group's PSC areas, except for the following subsidiaries, for which the extent of decommissioning and site restoration liabilities are still being clarified with the Government:

- PHM, PHSS and PHKT : Provisions for ASR are recognized for assets constructed during the current PSC terms;
- PHE OSES : Provision for ASR are recognized for assets that are currently being used by the PHE OSES.

As of the completion date of these consolidated financial statements, the discussions with the Government are still ongoing.

50. EVENTS AFTER THE REPORTING PERIOD

a. Changes in the composition of the Board of Commissioners

Based on the decision of the GMS No. SK-282/MBU/11//2019 dated November 22, 2019, Basuki Tjahaja Purnama, Budi Gunadi Sadikin, and Condro Kironohas were appointed as the new members of the Company's Board of Commissioner. Based on the same GMS decision, Tanri Abeng, Arcandra Tahar, and Gatot Trihargo were honorably relieved from their respective positions as the Company's Board of Commissioners. Thus, the composition of the Board of Commissioners as of September 30, 2019 is as follows:

President Commissioner	Basuki Tjahaja Purnama
Vice President Commissioner	Budi Gunadi Sadikin
Commissioner	Alexander Lay
Commissioner	Ego Syahrial
Commissioner	Condro Kirono
Commissioner	Suahasil Nazara

50. EVENTS AFTER THE REPORTING PERIOD (continued)

b. Changes in the composition of the Audit Committee

Based Decision Letter No. SK-016/KPTS/K/DK//2019 dated December 3, 2019, Basuki Tjahaja Purnama and Alexander Lay have been appointed as Chairman and Vice Chairman of the Company's Audit Committee replacing Tanri Abeng and Gatot Trihargo, who were honorably relieved from their respective positions as members of the Company's Audit Committee. Therefore, the composition of the Audit Committee as of September 30, 2019 is as follows:

Chairman	: Basuki Tjahaja Purnama
Vice Chairman	: Alexander Lay
Member	: Agus Yulianto
Member	: Bonar Lumban Tobing

c. Changes in the composition of the Board of Directors

Based on the decision of the Minister of State Owned Enterprise No. SK-283/MBU/11/2019 dated November 22, 2019, Pahala N. Mansury, who had been the Company's Finance Director since 2018, was honorably relieved of his duty, and is replaced by Emma Sri Martini.

d. West Ganal Gross Split

The West Ganal PSC was signed on October 18, 2019, by SKK Migas, PT Pertamina Hulu West Ganal, Eni West Ganal Limited and Neptune Energy West Ganal B.V. (collectively referred to as the "Contractors"), and has been approved on the same date by The Minister of Energy and Mineral Resources, on behalf of the Government of the Republic of Indonesia. The West Ganal PSC contract will be effective on January 26, 2020 with the Gross Split scheme and is applicable for 30 years since the effective date.

PT Pertamina Hulu West Ganal, Eni West Ganal Limited and Neptune Energy West Ganal B.V. have participating interests of 30%, 40%, and 30%, respectively. The operator for West Ganal Block is Eni West Ganal Limited.

The crude oil base split is 57% for the Government and 43% for the Contractors. Meanwhile, the natural gas base split is 52% for the Government and 48% for the Contractors.

The Contractors are obligated to pay signature bonus amounting to US$30,100 to the Government.of the Republic of Indonesia.

e. Corridor Gross Split PSC

The amended and restated Corridor Gross Split PSC was signed on November 11, 2019, by SKK Migas, ConocoPhillips (Grissik) Ltd., PT Pertamina Hulu Energi Corridor and Talisman (Corridor) Ltd., (collectively referred to as the "The Contractors") and has been approved on November 15, 2019 by The Minister of Energy and Mineral Resources, on behalf of the Government of the Republic of Indonesia. The amended and restated Corridor PSC contracts will be effective on December 20, 2023 with the Gross Split scheme and is applicable for 20 years since the effective date.

ConocoPhillips (Grissik) Ltd., PT Pertamina Hulu Energi Corridor and Talisman (Corridor) Ltd. have participating interest of 46%, 30%, and 24%, respectively. The operator for Corridor Block is ConocoPhillips (Grissik) Ltd.

The crude oil base split is 57% for the Government and 43% for the Contractors. Meanwhile the natural gas base split is 52% for the Government and 48% for the Contractors.

The Contractors are obligated to pay signature bonus amounting US$250,000 to the Government of the Republic of Indonesia.

f. Investment in new issuance shares of PT Tuban Petrochemical Industries ("Tuban Petro")

On November 18, 2019, the Company entered into the New Shares Purchase Agreement with Tuban Petro to purchase 190,372 new issuance series B shares of Tuban Petro for total consideration of Rp3,156,560,797,208 (full amount). This acquisition resulted in the Company owning 51% of Tuban Petro's shares and indirectly owning TPPI by 61.12%. On the same date, the Company, the Ministry of Finance and Tuban Petro entered into the Management Cooperation Agreement for strategic development of Indonesian petrochemical industry through the management of Tuban Petro and its subsidiaries/associates entities.

50. EVENTS AFTER THE REPORTING PERIOD (continued)

g. Reappointment PHE NSB in Blok B PSC

On October 2, 2019, PHE NSB was reappointed to temporary managed the B Working Area from October 4, 2019 to November 18, 2019 through MoEMR letter No. 8394/13/DJM.E/2019 dated October 2, 2019, which was extended to November 17, 2020 through MoEMR letter No. 512/13/MEM.M/2019 dated November 15, 2019 (Note 43d).

h. Firm commitment to conduct exploration activities

In accordance with the amended Gross Split PSC Jambi Merang Block dated October 14, 2019, the Company has firm commitment to conduct exploration activities in Indonesia open area with total committed spending of US$196,500 for the initial 5 (five) contract years.

ISSUER

PT Pertamina (Persero)
Jl. Medan Merdeka Timur 1A
Jakarta 10110, Indonesia

ARRANGERS & DEALERS

Citigroup Global Markets Inc.
388 Greenwich Street
New York, NY 10013
United States of America

Crédit Agricole Corporate and Investment Bank
30th Floor,
Two Pacific Place,
88 Queensway, Hong Kong

The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch
21 Collyer Quay
#10-01 HSBC Building
Singapore 049320

Mandiri Securities Pte. Ltd.
12 Marina View, #19-06
Asia Square Tower 2,
Singapore 018961

Mizuho Securities Asia Limited
14-15/F., K11 Atelier
18 Salisbury Road
Tsim Sha Tsui, Kowloon
Hong Kong

LEGAL ADVISORS

To the Issuer as to

New York and U.S. federal securities law:
Latham & Watkins LLP
9 Raffles Place
#42-02 Republic Plaza
Singapore 048619

Indonesian law:
Ali Budiardjo, Nugroho, Reksodiputro
Graha CIMB Niaga, 24th Floor
Jl. Jend. Sudirman Kav. 58
Jakarta 12190
Indonesia

To the Arrangers and the Dealers as to

New York and U.S. federal securities law:
Allen & Overy (Asia) Pte Ltd
50 Collyer Quay
#09-01 OUE Bayfront
Singapore 049321

Indonesian law:
Ginting & Reksodiputro in association with Allen & Overy LLP
The Energy Building, 15th Floor
Sudirman Central Business District
Jl Jend Sudirman Kav 52-53
Jakarta 12190, Indonesia

INDEPENDENT PUBLIC ACCOUNTANTS

KAP Purwantono, Sungkoro & Surja
(the Indonesian member firm of Ernst & Young Global Limited)
Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

PAYING AGENT

The Bank of New York Mellon, London Branch
One Canada Square London E14
5AL United Kingdom

TRUSTEE, REGISTRAR, TRANSFER AGENT AND PAYING AGENT

The Bank of New York Mellon
240 Greenwich Street
New York, New York 10286
United States of America

EURO REGISTRAR

The Bank of New York Mellon SA/NV, Luxembourg Branch
Vertigo Building-Polaris
2-4 rue Eugene Ruppert
L-2453 Luxembourg



PT PERTAMINA (PERSERO)

(a state-owned company incorporated in the Republic of Indonesia with limited liability)

US$10,000,000,000

Global Medium Term Note Program

SUPPLEMENTAL OFFERING MEMORANDUM

Arrangers & Dealers

Citigroup	**Crédit Agricole CIB**	**HSBC**	**Mandiri Securities**	**Mizuho Securities**

January 13, 2020

OFFERING MEMORANDUM



PT PERTAMINA (PERSERO)

(a state-owned company established in the Republic of Indonesia with limited liability)

US$10,000,000,000

Global Medium Term Note Program

Under this US$10,000,000,000 Global Medium Term Note Program (the "Program"), PT Pertamina (Persero) (the "Issuer"), a state-owned company established with limited liability under the laws of the Republic of Indonesia, subject to compliance with all relevant laws, regulations and directives, may, from time to time, issue notes in bearer or registered form (the "Notes").

The maximum aggregate principal amount of all Notes from time to time outstanding under the Program will not exceed US$10,000,000,000 (or its equivalent in other currencies determined at the time of agreement to issue), subject to any duly authorized increase. The Notes may be denominated in U.S. dollars, Euros and such other currencies as may be agreed between the Issuer and the Relevant Dealers (as defined below), subject to all legal and regulatory requirements applicable to issuances in particular currencies. The Notes may bear interest on a fixed or floating rate basis, be issued on a fully discounted basis and not bear interest, or be indexed.

The Notes may be issued on a continuing basis to the Dealers and any additional Dealer(s) appointed under the Program from time to time pursuant to the terms of an amended and restated program agreement dated October 19, 2018 as amended by an amendment agreement dated as of the date hereof (as the same may be further amended, supplemented or restated from time to time, the "Program Agreement"), which appointment may be for a specific issue or on an ongoing basis (each, a "Dealer" and, together, the "Dealers"). References in this Offering Memorandum to the "Relevant Dealer," in the case of an issue of Notes being (or intended to be) subscribed by more than one Dealer, shall be to all Dealers agreeing to subscribe for such Notes.

Notes will be issued in Series (each, a "Series"), with all Notes in a Series having the same maturity date and terms otherwise identical (except in relation to issue dates, interest commencement dates, issue prices and related matters). Notes of each Series may be issued in one or more tranches (each, a "Tranche") on different issue dates. Details applicable to each particular Series or Tranche will be supplied in a pricing supplement to this Offering Memorandum (each, a "Pricing Supplement"), which will contain the aggregate principal amount of the Notes, interest (if any) payable in respect of Notes, the issue price of Notes and any other terms and conditions not contained herein which are applicable to each Tranche. This Offering Memorandum may not be used to consummate sales of Notes, unless accompanied by a Pricing Supplement.

The price and amount of Notes to be issued under the Program will be determined by the Issuer and the Relevant Dealer at the time of issue in accordance with prevailing market conditions.

Application has been made to the Singapore Exchange Securities Trading Limited (the "SGX-ST") for permission to deal in and for the listing and quotation of any Notes that may be issued pursuant to the Program and which are agreed at or prior to the time of issue thereof to be so listed on the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained herein. Admission of any Notes to the Official List of the SGX-ST is not to be taken as an indication of the merits of the Issuer and its respective subsidiaries and associated companies, the Program or the Notes. Unlisted Notes may be issued under the Program. The relevant Pricing Supplement in respect of any Series will specify whether or not such Notes will be listed and, if so, on which exchange(s) the Notes are to be listed. There is no assurance that an application to the SGX-ST for the listing of the Notes of any Series will be approved.

Notes of each Series to be issued in bearer form ("Bearer Notes") will initially be represented by interests in a temporary global Note or by a permanent global Note, in either case in bearer form (each a "Temporary Global Note" and a "Permanent Global Note," respectively), without interest coupons, which may be deposited on the relevant date of issue (the "Issue Date") with a common depositary on behalf of Clearstream Banking, société anonyme ("Clearstream") and Euroclear Bank S.A./N.V. ("Euroclear") (the "Common Depositary") or any other agreed clearance system compatible with Euroclear and Clearstream and will be sold in an "offshore transaction" within the meaning of Regulation S ("Regulation S") under the United States Securities Act of 1933, as amended (the "Securities Act"). The provisions governing the exchange of interests in Temporary Global Notes and Permanent Global Notes (each, a "Bearer Global Note") for other Bearer Global Notes and individual definitive Bearer Notes ("Definitive Bearer Notes") are described in "Forms of the Notes." Definitive Bearer Notes will only be available in the limited circumstances as described herein.

Notes of each Series to be issued in registered form ("Registered Notes") sold in an offshore transaction will initially be represented by interests in a global unrestricted Note, without interest coupons (each an "Unrestricted Global Security"), which may be deposited on the issue date with the Common Depositary unless otherwise specified in the applicable Pricing Supplement. Beneficial interests in an Unrestricted Global Security will be shown on, and transfers thereof will be effected only through, records maintained by, Euroclear or Clearstream unless otherwise specified in the applicable Pricing Supplement. Notes of each Series sold to a qualified institutional buyer ("QIB") within the meaning of Rule 144A under the Securities Act ("Rule 144A"), as referred to in, and subject to the transfer restrictions described in, "Plan of Distribution" and "Transfer Restrictions" will initially be represented by interests in a global restricted Note, without interest coupons (each a "Restricted Global Security" and together with any Unrestricted Global Security, the "Registered Global Securities"), which will be deposited on the relevant issue date with a custodian for, and registered in the name of a nominee of, The Depository Trust Company ("DTC"). Beneficial interests in a Restricted Global Security will be shown on, and transfers thereof will be effected only through, records maintained by DTC and its participants. See "Global Clearance and Settlement Systems."

Notes in definitive registered form will be represented by registered certificates (each, a "Certificated Security"), one Certificated Security being issued in respect of each Noteholder's entire holding of Notes of one Series and will only be available in the limited circumstances as described herein.

Notes of any Series issued under the Program may be rated or unrated. When an issue of Notes is rated, its rating will not necessarily be the same as the rating applicable to the Program. A security rating is not a recommendation to buy, sell or hold securities and may be subject to suspension, reduction or withdrawal at any time by the assigning rating agency.

Investing in the Notes involves risk. See "Risk Factors" beginning on page 21 for a discussion of risks relevant to an investment in the Notes.

The Notes have not been and will not be registered under the Securities Act, or any state securities laws in the United States or any other jurisdiction, and the Notes may include Bearer Notes that are subject to U.S. tax law requirements. The Notes may be offered and sold (i) in the United States only to QIBs or to "accredited investors" (as defined in Rule 501(a)(1), (2), (3) or (7) under the Securities Act) ("Institutional Accredited Investors"), in each case in transactions exempt from registration under the Securities Act and/or (ii) outside the United States to non-U.S. persons in offshore transactions in reliance on Regulation S. In addition, subject to certain exceptions, Bearer Notes may not be offered, sold or delivered within the United States or to, or for the account or benefit of, United States persons (as defined in the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code")). See "Transfer Restrictions." . The Notes may not be offered or sold in Indonesia or to Indonesian citizens, wherever they are domiciled, or to Indonesian residents, in a manner which constitutes a public offering under Law Number 8 of 1995 on Capital Markets and its implementing regulations.

Arrangers & Dealers

Deutsche Bank **HSBC** **Mandiri Securities** **Standard Chartered Bank**

The date of this Offering Memorandum is July 23, 2019

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NOTICE TO INVESTORS

This Offering Memorandum is to be read in conjunction with all documents which are deemed to be incorporated herein by reference (see "Documents Incorporated by Reference" below).

No action has been or will be taken to permit a public offering of any Notes in any jurisdiction where action would be required for that purpose. No Notes may be offered or sold, directly or indirectly, and this Offering Memorandum may not be distributed in any jurisdiction, except in accordance with the legal requirements applicable in such jurisdiction.

If a jurisdiction requires that the offering be made by a licensed broker or dealer and the Dealers or any affiliate of the Dealers is a licensed broker or dealer in that jurisdiction, the offering shall be deemed to be made by that Dealer or its affiliate on behalf of the Issuer in such jurisdiction.

Neither this Offering Memorandum nor any other information supplied in connection with the Program or the Notes constitutes an offer of, or an invitation by or on behalf of our Company, Deutsche Bank AG, Singapore Branch, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd. and Standard Chartered Bank, as the arrangers of this Program (the "Arrangers"), any of the Dealers, or The Bank of New York Mellon, as trustee (the "Trustee") to subscribe for or purchase, any Notes. Subject as provided in the applicable Pricing Supplement, the only persons authorized to use this Offering Memorandum in connection with an offer of Notes are the persons named in the applicable Pricing Supplement as the Relevant Dealer or any other persons named in the section "Non-exempt Offer" of the Pricing Supplement (if any), as the case may be.

No person has been authorized to give any information or to make any representation other than those contained in this Offering Memorandum, and any information or representation not contained in this Offering Memorandum must not be relied upon as having been authorized by us, the Arrangers, any of the Dealers, the Trustee, the Paying Agent or the Registrar (each as defined herein) or any other person. Neither the delivery of this Offering Memorandum nor any sale of any Notes in connection therewith shall, under any circumstances, constitute a representation or create any implication that the information contained herein is correct as of any time subsequent to the date hereof or that there has been no change in the affairs of any party mentioned herein since that date.

No representation, warranty or undertaking, express or implied, is made by any of the Arrangers, any of the Dealers, or the Trustee, and no responsibility or liability is accepted by any thereof to the accuracy, adequacy, reasonableness or completeness of the information contained in this Offering Memorandum or any other information provided by us in connection with the Notes, their distribution or their future performance. To the fullest extent permitted by law, none of the Dealers or the Arrangers accept any responsibility for the contents of this Offering Memorandum or for any other statement, made or purported to be made by the Arrangers or a Dealer or on any of their behalf in connection with the Issuer or the issue and offering of the Notes. Each Arranger and each Dealer accordingly disclaims all and any liability whether arising in tort or contract or otherwise (save as referred to above) which it might otherwise have in respect of this Offering Memorandum or any such statement.

Neither this Offering Memorandum nor any other information supplied in connection with the Program or the Notes should be considered as a recommendation by us, the Arrangers, any of the Dealers or the Trustee that any recipient of this Offering Memorandum should purchase any of the Notes. Each investor contemplating purchasing any Notes should make its own independent investigation of our business, financial condition and affairs, and its own appraisal of our creditworthiness.

The Notes have not been approved or disapproved by the United States Securities and Exchange Commission (the "SEC"), any state securities commission in the United States or any other U.S. regulatory authority, nor have any of the foregoing authorities passed upon or endorsed the merits of the offering of the Notes or the accuracy or adequacy of this Offering Memorandum. Any representation to the contrary is a criminal offense in the United States.

In connection with the issue of Notes in any Series or Tranche under the Program, the Relevant Dealer or Relevant Dealers (if any) names as the stabilizing manager(s) (the "Stabilizing Manager(s)") in the applicable Pricing Supplement, or any person acting for the Stabilizing Manager(s), may purchase and sell such Notes in the open market. These transactions may, to the extent permitted by applicable laws and regulations, include short sales, stabilizing transactions and purchases to cover positions created by short sales. These activities may stabilize, maintain or otherwise affect the market price of such Notes. As a result, the price of such Notes may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued at any time and must in any event be brought to an end after a limited time. There is no obligation on the Stabilizing Manager(s) or any of the Relevant Dealers to carry out such activities. These activities will be undertaken solely for the account of Stabilizing Manager(s) and/or the Relevant Dealers and not for or on our behalf.

DOCUMENTS INCORPORATED BY REFERENCE

This Offering Memorandum should be read and construed in conjunction with each relevant Pricing Supplement and all other documents which are deemed to be incorporated by reference in the relevant Offering Memorandum and in the relevant Pricing Supplement. The relevant Offering Memorandum and the relevant Pricing Supplement shall, save as specified herein and therein, be read and construed on the basis that such documents are so incorporated by reference and form part of the relevant Offering Memorandum and the relevant Pricing Supplement.

Following the date of this Offering Memorandum, this Offering Memorandum should also be read and construed in conjunction with the most recently published audited consolidated financial statements, and any interim consolidated financial statements (whether audited or unaudited) published subsequently to such consolidated financial statements, of our Company from time to time, which are published on the website of the SGX-ST (www.sgx.com) and/or published on our Company's website (www.pertamina.com), which shall be deemed to be incorporated in, and to form part of, this Offering Memorandum and which shall be deemed to modify or supersede the contents of this Offering Memorandum to the extent that a statement contained in any such document is inconsistent with such contents.

Copies of documents deemed to be incorporated by reference in this Offering Memorandum may be obtained without charge from the registered office of our Company.

SUPPLEMENTAL OFFERING MEMORANDUM

If at any time we shall be required to prepare a supplemental Offering Memorandum, we will prepare and make available an appropriate amendment or supplement to this Offering Memorandum or a further Offering Memorandum.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED KINGDOM

The Notes may not be offered or sold to any person in the United Kingdom, other than to persons whose ordinary activities involve them acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses or otherwise in circumstances which have not resulted and will not result in an offer to the public in the United Kingdom.

NOTICE TO PROSPECTIVE INVESTORS IN CANADA

The Notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the Notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws. Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor. Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

MIFID II PRODUCT GOVERNANCE/TARGET MARKET

The Pricing Supplement may include a legend entitled "MiFID II Product Governance" which will outline the target market assessment in respect of the Notes and which channels for distribution of the Notes are appropriate. Any person subsequently offering, selling or recommending the Notes (a "distributor") should take into consideration the target market assessment; however, a distributor subject to Directive 2014/65/EU (as amended, "MiFID II") is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the target market assessment) and determining appropriate distribution channels.

A determination will be made in relation to each issue about whether, for the purpose of the MiFID Product Governance rules under EU Delegated Directive 2017/593 (the "MiFID Product Governance Rules"), any Dealer subscribing for any Notes is a manufacturer in respect of such Notes, but otherwise, unless so determined, neither the Arrangers nor the Dealers nor any of their respective affiliates will be a manufacturer for the purpose of the MiFID Product Governance Rules.

PROHIBITION OF SALES TO EEA RETAIL INVESTORS

If the Pricing Supplement in respect of any Notes includes a legend entitled "Prohibition of Sales to EEA Retail Investors," the Notes are not intended to be offered, sold or otherwise made available to

and should not be offered, sold or otherwise made available to any retail investor in the European Economic Area ("EEA"). For these purposes, a retail investor in the EEA means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of MiFID II; (ii) a customer within the meaning of Directive 2002/92/EC (as amended, the "Insurance Mediation Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; and (iii) not a qualified investor as defined in the Prospectus Directive (as defined herein). Consequently, no key information document required by Regulation (EU) No 1286/2014 (the "PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.

NOTIFICATION UNDER SECTION 309B(1)(C) OF THE SECURITIES AND FUTURES ACT (CHAPTER 289) OF SINGAPORE

Unless otherwise stated in the Pricing Supplement in respect of any Notes, all Notes issued or to be issued under the Program shall be prescribed capital market products (as defined in the Securities and Futures (Capital Markets Products) Regulations 2018) and Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

NOTICE TO PROSPECTIVE INDONESIAN INVESTORS

The Notes have not been offered or sold and will not be offered or sold in the Republic of Indonesia or to any Indonesian nationals, corporations or residents, including by way of invitation, offering or advertisement, and this Offering Memorandum and any other offering material relating to the Notes has not been distributed, and will not be distributed, in the Republic of Indonesia or to any Indonesian nationals, corporations or residents in a manner which would constitute a public offering in the Republic of Indonesia under Law Number 8 of 1995 on Capital Markets. The Indonesian Financial Service Authority (*Otoritas Jasa Keuangan* or the "OJK") has not reviewed or declared its approval or disapproval of the issue of the Notes, nor has it made any determination as to the accuracy or adequacy of this Offering Memorandum. Any statement to the contrary is a violation of Indonesian law.

ENFORCEABILITY OF FOREIGN JUDGMENTS IN INDONESIA

The Issuer is a state-owned limited liability company established and existing in Indonesia. All of our commissioners, directors and executive officers reside in Indonesia. Substantially all of the assets of the Issuer and these other persons are located outside the United States. As a result, it may be difficult for investors to effect service of process upon such persons within the United States, or to enforce against us in court, judgments obtained in U.S. courts, including judgments predicated upon the civil liability provisions of the federal securities laws of the United States.

We have been advised by our Indonesian legal advisor, UMBRA Partnership, that judgments of courts outside Indonesia are not enforceable in Indonesian courts. A foreign court judgment could be offered and accepted into evidence in a proceeding on the underlying claim in an Indonesian court and may be given such evidentiary weight as the Indonesian court may deem appropriate in its sole discretion. A claimant may be required to pursue claims in Indonesian courts on the basis of

Indonesian law. A purchaser of the Notes may not be able to enforce judgments against us obtained in the United States based upon certain of the civil liability provisions of the securities laws of the United States or any states thereof in Indonesian courts, and Indonesian courts may not enter judgments in original actions brought in Indonesian courts based solely upon the civil liability provision of the securities laws of the United States or any state thereof. Re-examination of the underlying claim would be required before the Indonesian court. There can be no assurance that the claims or remedies available under Indonesian law will be the same, or as extensive as those available in other jurisdictions. For more details, see "Risk Factors — Risks Relating to Indonesia — It may not be possible for investors to effect service of process or to enforce certain judgments on the Issuer or its management" and "Risk Factors — Risks Relating to Indonesia — Holders of the Notes will be exposed to a legal system subject to considerable discretion and uncertainty and may have difficulty pursuing claims under the Notes."

INDONESIAN REGULATION OF OFFSHORE BORROWINGS

Pursuant to Presidential Decree No. 39 of 1991, we are required to obtain prior approval from the Offshore Commercial Borrowing Team (the "PKLN Team") to receive offshore borrowings and must submit periodic reports to the PKLN Team. However, the decree does not stipulate either the time frame or the format and the content of the periodic report that must be submitted. Under Presidential Decree No. 59 of 1972, dated October 12, 1972, as partly revoked by the Presidential Decree No. 15 of 1991 on Receipt of Offshore Loans and Issuance of Bank Guarantees for the Acceptance of Offshores Loans by State-Owned Banks and Regional Development Banks Stipulated as Foreign Exchange Banks ("PD 59/1972"), we are required to obtain approval from the Minister of Finance of Indonesia and report the particulars of our offshore commercial borrowings to the Minister of Finance of Indonesia and Bank Indonesia, on the acceptance, implementation, and repayment of principal and interest. In practice, this approval from the Minister of Finance under PD 59/1972 is considered to have been obtained when approval from the PKLN Team is received because the Minister of Finance of Indonesia is a member of the PKLN Team. Minister of Finance Decree No. KEP-261/MK/IV/5/1973 dated May 3, 1973, as amended by the Minister of Finance Decree No. 417/KMK.013/1989 dated May 1, 1989 and partly revoked by the Minister of Finance Decree No. 279/KMK.01/1991 dated March 18, 1991, as the implementing regulation of this PD 59/1972, further sets forth the requirement to submit periodic reports to the Minister of Finance of Indonesia and Bank Indonesia on the effective date of the contract and each subsequent three-month period.

See "Indonesian Regulatory Framework — Indonesian Regulation of Offshore Borrowings" for information on certain regulations in Indonesia which apply to our offshore borrowings.

LANGUAGE OF TRANSACTION DOCUMENTS

Pursuant to Law No. 24 of 2009, regarding Flag, Language, Coat of Arms and National Anthem enacted on July 9, 2009 ("Law No. 24"), agreements to which Indonesian entities are a party are required to be executed in Bahasa Indonesia, although dual language documents are permitted when a foreign entity is a party. There exists substantial uncertainty regarding how Law No. 24 will be interpreted and applied in general and to date the Government has only issued one implementing regulation relating to the use of Bahasa Indonesia in formal speeches by the President, Vice President and other state officers of Indonesia. In addition to this implementing regulation, the Minister of State-Owned Enterprises has also issued a Circular Letter No. SE-12/MBU/2009 dated November 3, 2009, which recommends that any state-owned enterprise must use Bahasa Indonesia in every

memorandum of understanding or agreement to which such state-owned enterprise is a party. The Indonesian Ministry of Law and Human Rights has issued a clarification letter No. M.HH.UM.01.01-35 TAHUN 2009, dated December 28, 2009 regarding Clarification for Implication and Implementation of Law No. 24 (the "Ministry of Law and Human Rights Clarification Letter") to clarify that the implementation of Law No. 24 is contingent upon the enactment of a Presidential Regulation and until such a Presidential Regulation is enacted, any agreement that is executed prior to the enactment of the Presidential Regulation in English without a Bahasa Indonesia version, is still legal and valid, and shall not violate Law No. 24. This letter was issued only as an opinion and does not fall within the types and hierarchy as stipulated in Article 7 of Law No. 12 of 2014 regarding the Formation of Laws and Regulations, thus the letter cannot be considered as law or regulation. Therefore, the Ministry of Law and Human Rights Clarification Letter has no legal force and we cannot be certain that an Indonesian court would permit the English version to prevail or even consider the English version.

We will execute both English and Bahasa Indonesia versions of all transaction agreements to which the Issuer is a party. All of these documents will provide that in the event of a discrepancy or inconsistency, the parties agree that the English version would prevail and the Bahasa Indonesia version will be read as amended to conform with the provisions of the English version. However, we cannot be certain that an Indonesian court would permit the English version to prevail or even consider the English version. Furthermore, some concepts in English may not have corresponding terms in Bahasa Indonesia and thus the exact meaning of the English version may not be fully captured by the Bahasa Indonesia version. If this occurs, we cannot assure you that the terms of the Notes, the Indenture and the Program Agreement, will be as described in this Offering Memorandum or will be interpreted and enforced by the Indonesian courts as described in this Offering Memorandum. See "Risk Factors — Risks Relating to the Notes — The Indenture and certain other documents entered into in connection with the Program or any issue of Notes thereunder will also be prepared in Bahasa Indonesia as required under Indonesian law. However, there can be no assurance that, in the event of inconsistencies between the Bahasa Indonesia and English language versions of these documents, an Indonesian court would hold that the English language versions of such documents would prevail."

CERTAIN DEFINED TERMS AND CONVENTIONS

As used in this Offering Memorandum, unless the context otherwise requires, the terms "we," "us," "our," "our Company" and "Pertamina" refer to PT Pertamina (Persero) and its consolidated subsidiaries and the term the "Issuer" refers to PT Pertamina (Persero) on a standalone basis.

In this Offering Memorandum, references to "US$," "$" and "U.S. dollars" are to United States dollars, the legal currency of the United States, references to "Rupiah" and "Rp." are to the legal currency of Indonesia, references to "€" and "Euro" are to the legal currency of certain member states of the European Union and references to "¥" and "Japanese Yen" are to the legal currency of Japan . Unless otherwise specified or the context otherwise requires, all references to "Indonesia" are references to the Republic of Indonesia. All references to the "Government" herein are references to the Government of the Republic of Indonesia. All references to "United States" or "U.S." herein are references to the United States of America. Certain terms used herein are defined in the "Glossary" contained elsewhere in this Offering Memorandum.

Unless otherwise expressly stated, all operational data of our Company contained in this Offering Memorandum is given as of March 31, 2019.

All references herein to the "Oil and Gas Law of 2001" are references to the oil and gas law enacted on November 23, 2001 as partially annulled by the Constitutional Court of the Republic of

Indonesia on December 15, 2004 and November 13, 2012. References to "SKK MIGAS" are references to the Special Working Unit for the Implementation of Upstream Natural Oil and Gas Business Activity (Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi) and references to "BPMIGAS" are references to the predecessor to SKK MIGAS, the Executive Agency for Upstream Oil and Gas Activities (Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi), a non-profit Government-owned legal entity which was dissolved pursuant to the decision of the Constitutional Court of the Republic of Indonesia Decision No. 36/PUU-X/2012 dated November 13, 2012. References to "BPH MIGAS" are references to the Oil and Gas Downstream Regulatory Body (Badan Pengatur Hilir Minyak dan Gas Bumi), an independent governmental agency. For more information see "Indonesian Regulatory Framework."

See "Business — Pertamina Upstream Business — Reserves" for definitions of net reserves, proved reserves, proved plus probable reserves, proved developed reserves and proved undeveloped reserves.

See "Business — Pertamina Upstream Business — Production" for a definition of production and net production in respect of our upstream business. See "Indonesian Regulatory Framework" for a description of the production sharing arrangements between us and the Government.

Our working interest is given after taking into account any dilution due to ownership through subsidiaries which are less than wholly owned, directly or indirectly, by us.

In respect of our downstream businesses, unless otherwise specified, all references herein to "production capacity" of a facility means the maximum amount that can, or is expected to be able to, be produced by such facility. No representation is made that the amount of production (if any) from such facility is or will or is expected to be equal to the production capacity of a facility and production capacity should not be treated as indicative of future levels of production.

Unless otherwise indicated or in the case of oil prices, references to "crude oil" or "oil" include condensate. Natural gas equivalents and crude oil equivalents are determined using the ratio of 1 mmcf of natural gas to 0.1726 mboe of oil equivalent, except in "Industry Overview," where natural gas equivalents and crude oil equivalents are determined using the ratio of 1 mmcf of natural gas to 0.176 mboe of oil equivalent.

INDUSTRY AND MARKET DATA

This Offering Memorandum includes certain industry and market data (including forecasts and other forward-looking information) obtained from, among others, the Central Bureau of Statistics (Badan Pusat Statistik, formerly known as Biro Pusat Statistik), the World Bank and reports of other governmental agencies, industry publications and surveys, and internal company surveys. Such industry publications and surveys and forecasts generally state that the data contained therein has been obtained from sources believed to be reliable, but we cannot assure you that such data is complete or accurate, nor has such data been independently verified, and neither we, nor the Arrangers or any Dealer make any representation as to the accuracy or completeness of such data or any assumptions relied upon therein.

This Offering Memorandum, including the section titled "Industry Overview," also contains certain industry and market data derived from a report commissioned by us and prepared by our energy industry consultant Wood Mackenzie Asia Pacific Pte Ltd ("Wood Mackenzie") titled "*Indonesia Oil and Gas Industry Report (Final): July 2019*" (the "Wood Mackenzie Report"). Other than information

about Pertamina that was provided by us to Wood MacKenzie, the industry and market data in the Wood Mackenzie Report has not been independently verified by us, the Arrangers or the Dealers, and neither we, except with respect to information which we have provided, nor the Arrangers or any Dealer make any representation as to the accuracy or completeness of such data or any assumptions relied upon therein.

The Wood Mackenzie Report contains certain data produced by Wood Mackenzie about Indonesia's and our oil and gas reserves. Wood MacKenzie's categorization of oil and gas reserves as "commercial reserves" and "technical reserves" is not part of a system of oil and gas reporting definitions that is recognized by a professional standards-setting body or a securities regulator. Pertamina reports its oil and gas reserves under its oil and gas resource management system, which is consistent with the Petroleum Resource Management System ("PRMS") approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers. See also "Presentation of Financial and Other Data — Oil and Gas Reserves" and "Business — Pertamina Upstream Business — Oil and Gas Reserves." Investors should carefully consider the differences between the categories Wood MacKenzie employs and the industry-standard categories that Pertamina uses to calculate its oil and gas reserves and resources. Investors should not assume that quantities of oil and gas that Wood Mackenzie describes as reserves or resources would be categorized as reserves or resources under the PRMS.

Financial data with respect to Indonesia provided in this Offering Memorandum may be subsequently revised in accordance with Indonesia's ongoing maintenance of its economic data, and such revised data will not be distributed by us to any holder of the Notes.

PRESENTATION OF FINANCIAL AND OTHER DATA

Exchange Rate Information

Solely for convenience, this Offering Memorandum contains translations of certain Rupiah amounts into U.S. dollars at the exchange rate of Rp. 14,240.50 = US$1.00, which was the middle exchange rate according to Bloomberg Finance LP as of March 29, 2019 and translations of certain Japanese Yen amounts into U.S. dollars at the exchange rate of ¥100 = US$0.90 which was the middle exchange rate according to Bloomberg Finance LP as of March 29, 2019 and certain Euro amounts into U.S. dollars at the exchange rate of €0.89 = US$1.00, which was the middle exchange rate according to Bloomberg Finance LP as of March 29, 2019. These translations should not be construed as representations that the Rupiah amounts represent such U.S. dollar amounts or could be, or could have been, converted into U.S. dollars at the rates indicated or at all. See "Exchange Controls" for further information regarding the rates of exchange between the Rupiah and the U.S. dollar.

Financial Information

Our consolidated financial statements and, unless otherwise indicated, financial information in this Offering Memorandum has been prepared in accordance with Indonesian Financial Accounting Standards ("IFAS"), which differ in certain respects from generally accepted accounting principles in the United States ("U.S. GAAP"). For a summary of certain differences between IFAS and U.S. GAAP, see "Summary of Certain Significant Differences Between IFAS and U.S. GAAP." Except as otherwise indicated or the context otherwise requires, financial information in this Offering Memorandum is presented on a consolidated basis.

Our consolidated financial statements as of December 31, 2018, 2017 and 2016 and for the years then ended included in this Offering Memorandum have been audited by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public

accountants, in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants (the "IICPA"), as stated in their audit report appearing elsewhere in this Offering Memorandum.

Our unaudited interim consolidated financial statements as of March 31, 2019 and for the three-month periods ended March 31, 2019 and 2018 have been reviewed by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with SRE 2410, established by the IICPA, as stated in their review report appearing elsewhere in this Offering Memorandum (presented combined with the audit report mentioned above). A review conducted in accordance with SRE 2410 established by the IICPA is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the IICPA, and as stated in their review report appearing in this Offering Memorandum (presented combined with the audit report mentioned above), KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountant, did not audit and do not express any opinion on such unaudited interim consolidated financial statements included elsewhere in this Offering Memorandum

Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements

In April 2018, the Issuer acquired the Government's 56.96% interest in PT Perusahaan Gas Negara Tbk ("PGN") to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. At the time, the Issuer and PGN held 60.0% and 40.0%, respectively, of PT Nusantara Regas ("Regas"), which develops and operates liquefied natural gas ("LNG") storage facilities and regasification terminals. As a result of the Issuer's acquisition of PGN, the Issuer has 82.78% effective ownership of Regas and control over its activities. Accordingly, the Issuer has consolidated Regas in its consolidated financial statements since the acquisition of PGN completed.

Under SFAS 38 (Revised 2012) "Business Combination between Entities Under Common Control" ("SFAS 38"), a business combination transaction that entails the transfer or reorganization of businesses under the same business group is not a change of ownership in economic substance. The pooling-of-interests method of accounting is applied, and the acquisition does not result in a gain or loss for the group as a whole or to the individual entity within the same group.

The transactions described above were considered common control business combinations. As a consequence of the application of SFAS 38, components of our consolidated statement of financial position as of December 31, 2016 and 2017 and components of our consolidated statements of comprehensive profit or loss and other comprehensive income for the years ended December 31, 2016 and 2017 were restated in June 2018 to present them in such a manner as if our acquisition of PGN had already occurred since the beginning of the period in which the entities were under common control.

In December 2018, PGN acquired from the Issuer a 51.0% stake in PT Pertamina Gas. Through the acquisition of PT Pertamina Gas, PGN also acquired PT Pertamina Gas' subsidiaries PT Pertagas Niaga, PT Perta Arun Gas, PT Perta Daya Gas and PT Perta Samtan (such subsidiaries together with PT Pertamina Gas, "Pertagas"). The Issuer retains a 49.0% direct stake in PT Pertamina Gas. While the Issuer's effective total ownership in PT Pertamina Gas (i.e. including its indirect stake via its ownership of PGN) is reduced from 100.0% to 78.05%, the transfer of Pertagas to PGN is intended to grow our gas business by creating an extensive and far-reaching distribution and transmission pipeline network in Indonesia and unlocking benefits of scale.

Certain operational data of PGN and its subsidiaries (including Pertagas) has been included in this Offering Memorandum. Unless otherwise stated, the operational data of Pertamina in this Offering

Memorandum (including relating to our natural gas transmission and distribution, LNG production, upstream and downstream oil and gas businesses and strategies, proved plus probable oil and gas reserves, exploratory and development wells, oil and gas fields/blocks and upstream oil and gas production and distribution) excludes the operational data of PGN and its subsidiaries. The information regarding PGN's upstream oil and gas business in the section "Business — Pertamina Upstream Business — PGN's Upstream Business" has been derived from PGN's annual report for 2018.

In this Offering Memorandum, references to our "net income" are to our "profit for the period/year after the effect of merging entity's income adjustment attributable to owners of the parent entity."

For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Our Recently Acquired Subsidiary, PGN" and our consolidated financial statements and the accompanying notes thereto included elsewhere in this Offering Memorandum.

Rounding

Rounding adjustments have been made in calculating some of the financial information and reserves and production information included in this Offering Memorandum. As a result, numerical figures shown as totals in some tables may not be exact arithmetic aggregations of the figures that precede them.

Non-GAAP Financial Measures

This Offering Memorandum includes certain non-GAAP financial measures for Pertamina, including Adjusted EBITDA and dividend payout ratio. Adjusted EBITDA and the related ratios presented in this Offering Memorandum and dividend payout ratio are supplemental measures of our performance and liquidity that are not required by, or presented in accordance with, IFAS or U.S. GAAP. Adjusted EBITDA is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to profit for the period/year after the effect of merging entity's income adjustment attributable to owners of the parent entity (which is our net income), operating income or any other performance measures derived in accordance with IFAS or U.S. GAAP or as an alternative to cash flow from operating activities or as a measure of liquidity. In addition, Adjusted EBITDA is not a standardized term, hence a direct comparison between companies using such a term may not be possible.

We calculate Adjusted EBITDA in accordance with *Kementerian Badan Usaha Milik Negara* (Indonesia's Ministry of State Owned Enterprises), or Decree of the Minister of State-Owned Enterprises Number: Kep-100/MBU/2002 concerning Assessment of the Health Level of State-Owned Enterprises (*Keputusan Menteri Badan Usaha Milik Negara Nomor: Kep-100/MBU/2002 Tentang Penilaian Tingkat Kesehatan Badan Usaha Milik Negara*) ("**BUMN Regulation KEPMEN 100**"), which requires adjustment for all finance costs and does not take into account the effects of merging entity's income adjustment, which arise in connection with acquisitions during the year or period. In comparison, our calculations of EBITDA in the past adjusted for interest expense and not accretion expenses related to decommissioning and site restoration or other finance costs and took into account the effects of merging entity's income adjustment. Adjusted EBITDA and the related ratios presented in this Offering Memorandum are therefore not comparable to our previously disclosed EBITDA and related ratios.

See "Summary Consolidated Financial and Other Data" and "Selected Consolidated Financial and Other Data" for more information, including details of our calculation of Adjusted EBITDA and a reconciliation of our net income under IFAS to our definition of Adjusted EBITDA.

Oil and Gas Reserves

Except where attributed to Wood Mackenzie, the information on our historical oil and gas reserves in this Offering Memorandum is based on our estimated "net reserves" and, as such, represents our aggregate share of the estimated crude oil and/or natural gas reserves in all blocks or fields or specified areas, attributable to our working interest in such areas, before deducting the share payable to the Government as owner of the reserves pursuant to the terms of the relevant production sharing arrangement, the cost recovery portion and any applicable taxes.

These estimates have been prepared based on our oil and gas and geothermal resource management system, which contains procedures for classifying and estimating reserves. Until December 31, 2018, the procedures for our oil and gas resource management system and the classifications of our reserves were consistent with PRMS approved in March 2007 ("PRMS 2007") by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. PRMS 2007 was generally considered the oil and gas industry standard for reserve reporting until it was superseded by a new PRMS released in June 2018 ("PRMS 2018"). Accordingly, in this Offering Memorandum, except where attributed to Wood Mackenzie, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. With respect to our reserves managed by PEP, prior to 2017 we had used the SPE 2001 guidelines (which were replaced by PRMS 2007) to determine the procedures for our oil and gas resource management system and the classifications of PEP's reserves. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007.

Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

Estimates of reserves are largely dependent on the interpretation of data obtained from drilling, testing and production and may prove to be incorrect over time. Estimates of proved reserves that may be developed and produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs, rather than upon actual production history. Subsequent evaluation of the same reservoirs based upon production history may result in revisions to the estimated proved or proved plus probable reserves. An estimate of reserves is based in part on a field's long-term development plan, and reserves are classified or adjusted and re-classified as contingent where a long-term development plan has not been finalized or is not up-to-date. The estimation of reserves involves a significant degree of judgment by our management, engineers and technical personnel. Reserves estimates are subject to various uncertainties, including those relating to the physical characteristics of oil and gas fields, as well as changes in oil prices. These uncertainties are difficult to estimate and, as a result, actual production may be materially different from current estimates of reserves. No assurance can be given that the reserves presented in this Offering Memorandum will be recovered at the levels presented. See "Risk Factors — Risks Relating to Our Upstream Operations — Our crude oil, natural gas and geothermal reserve estimates are uncertain and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these resources."

See "Business — Pertamina Upstream Business — Reserves" for definitions relating to our reserves and details of our reserve estimation methodology and techniques.

Cautionary Note to United States Investors Concerning Estimates of Measured, Indicated and Inferred Resources for Oil and Gas Programs

There are principal differences between the reporting regimes under the PRMS 2007, PRMS 2018 and in the United States under the requirements as adopted by the SEC in its Industry Guide 4 — Prospectus Relating to Interests in Oil and Gas Programs and Subpart 1200 of Regulation S-K (together "Industry Guide 4").

UNITED STATES INVESTORS ARE ADVISED THAT THE REPORTING REGIMES USED IN THIS OFFERING MEMORANDUM ARE ACCORDINGLY NOT COMPLIANT WITH INDUSTRY GUIDE 4.

AVAILABLE INFORMATION

In the event that Notes are offered and sold in reliance on Rule 144A, we shall, for so long as any of the Notes are "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act, during any period in which we are not subject to Section 13 or 15(d) of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"), or exempt from reporting pursuant to Rule 12g3-2(b) under the Exchange Act, make available to any qualified institutional buyer (as defined in Rule 144A) who is a holder of such restricted securities and any prospective purchaser of such restricted securities who is a qualified institutional buyer (as so defined) designated by such holder, upon the request of such holder or prospective purchasers, the information concerning us required to be provided to such holder or prospective purchaser by Rule 144A(d)(4) under the Securities Act.

FORWARD-LOOKING STATEMENTS

This Offering Memorandum includes, and any amendment or supplement, may include forward-looking statements. All statements other than statements of historical facts included in this Offering Memorandum and any amendment or supplement regarding, among other things, our future financial position and results of operations, business, strategy, plans, developments and prospects, the condition and prospects of the oil, gas and geothermal industries, and Indonesia's economy, fiscal condition, debt or prospects may constitute forward-looking statements. Forward-looking statements can generally be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "continue" or similar terminology. Specifically, statements under the captions "Summary," "Industry Overview," "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Business," "Indonesian Regulatory Framework" and "Relationship with the Government" relating to the following matters may include forward-looking statements relating to:

- the expected results of our exploration, development, production, refining and distribution activities and related capital expenditures and investments;
- our oil, gas and geothermal reserve estimates, the classification of our oil, gas and geothermal reserves and our ability to extract oil, gas and geothermal energy;
- our strategic, business and financial plans and objectives, including budgeted and future capital expenditures, acquisitions and investments, (i) in respect of future oil, gas and

geothermal exploration, development and production; (ii) in respect of the future construction, expansion, production capacity and utilization of our refining and other facilities; and (iii) in respect of the future construction, expansion, acquisition or operation of our distribution, trading and transportation networks;

- the anticipated demand and selling prices for crude oil, natural gas, geothermal energy, refined petroleum and petrochemical products, drilling activities and power;

- sales to existing and potential customers, whether under sales contract or not, and generation of future receivables;

- our ability to be and remain competitive in each of our main business segments;

- our financial position, business strategy and budget, including projected financial and operating data;

- existing and future regulatory requirements applicable to us and our businesses; and

- existing and future obligations in respect of environmental compliance and remediation.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various important factors, including those set out in this Offering Memorandum. Factors that could cause actual results to differ include, but are not limited to, the following:

- changes and volatility in market prices of or demand for key commodities produced or consumed by us, including crude oil and natural gas, as a result of competitive actions, economic factors such as inflation or exchange rate fluctuations, or otherwise;

- changes in our relationship with the Government, SKK MIGAS, BPH MIGAS and other government authorities in Indonesia and other countries in which we operate, our joint venture partners, our shareholder, our co-investors and other counterparties, in Indonesia and other countries in which we operate;

- whether we have or are able to obtain sufficient working capital to meet our cash and operational requirements, including through external financing;

- operational risks and hazards, such as accidents, natural disasters and other catastrophes;

- increases or other changes in regulatory burdens and obligations in Indonesia and other countries, including our public service obligation ("PSO"), dividend obligations, and environmental regulations and compliance costs;

- our ability to implement our growth strategy and development plans, including our ability to consummate future acquisitions, joint ventures or investments;

- economic, social and political conditions in Indonesia and other countries in which we operate;

- changes in terms and conditions of the agreements under which we operate our businesses and the ability of third parties to perform in accordance with contractual terms and specifications;

- changes in import or export controls, duties, levies or taxes, either in international markets or in Indonesia;

- changes in laws and regulations and their interpretation, applicable taxes and tax rates, accounting standards or practices, and reserve reporting guidelines; and

- our ability to manage the risks described above and in the section captioned "Risk Factors."

Although we believe that the expectations of our management as reflected by such forward-looking statements are reasonable based on information currently available to us, no assurances can be given that such expectations will prove to be correct.

In addition, our management's expectations with respect to our exploration, production, development, refining and distribution activities are subject to risks arising from the inherent difficulty of predicting the presence, yield or quality of oil, gas and geothermal reserves, as well as unknown or unforeseen difficulties in extracting, transporting, refining or processing any oil, gas or geothermal energy found, or doing so on a commercial basis.

Our ability to maintain and grow our revenues, net income and cash flows depends upon continued capital expenditure. In addition, our capital expenditure and investment plans are subject to a number of risks, contingencies and other factors, such as oil and gas prices, market demand, geological factors, acquisition opportunities and the success of our exploration program, some of which are beyond our control. Our ability to obtain adequate financing to satisfy our capital expenditure and investment budget and debt service requirements may be limited by our financial condition, results of operations, legal and regulatory issues and the liquidity of international and domestic financial markets. We may make additional capital expenditures and investments as opportunities or needs arise, and may increase, reduce or suspend our planned capital expenditures or investments or change the timing and use of its capital expenditures from what is currently planned in response to market conditions, drilling results, production trends or for other reasons.

Should one or more of these uncertainties or risks, among others, materialize, our actual results may vary materially from those estimated, anticipated or projected. Specifically, but without limitation, capital costs could increase, projects could be delayed, and anticipated improvements in production, capacity or performance might not be fully realized or realized at all.

Accordingly, prospective purchasers are cautioned not to place undue reliance on forward-looking statements. In any event, these statements speak only as of their dates, and we undertake no obligation to update or revise any of them, whether as a result of new information, future events or otherwise.

SUMMARY

This summary highlights information contained elsewhere in this Offering Memorandum. This summary is qualified by, and must be read in conjunction with, the more detailed information and the consolidated financial statements appearing elsewhere in this Offering Memorandum. We urge you to read this entire Offering Memorandum carefully, including our consolidated financial statements and related notes and "Risk Factors."

Overview

We are a fully integrated national oil, gas and geothermal company, wholly owned by the Government and headquartered in Jakarta, Indonesia. We have an operating history of more than 60 years. We were established on December 10, 1957 and became an Indonesian limited liability company in 2003.

We are engaged in a broad spectrum of upstream and downstream oil, gas, geothermal, petrochemical and other energy operations. Our lines of business are organized into upstream and downstream sectors in accordance with Indonesian oil, gas and geothermal regulations. In the upstream sector, we engage in the exploration (the search for oil, gas and geothermal energy), development (the drilling and bringing into production of wells in addition to the discovery wells in a field) and production and supply of crude oil, natural gas and geothermal energy in Indonesia and internationally. In the downstream sector, we carry out refining, marketing, distribution and trading of crude oil, natural gas, refined fuel products and petrochemical and other non-fuel products such as green coke, including products for retail, industrial and aviation uses. We are also mandated by the Government to distribute subsidized fuel, liquefied petroleum gas ("LPG") and compressed natural gas ("CNG") in Indonesia and to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program and to encourage the use of CNG as an alternative fuel.

As of March 31, 2019, our total net proved oil and gas reserves were an estimated 2,126.3 mmboe and our total net proved plus probable oil and gas reserves were an estimated 2,692.2 mmboe. We have the largest base of oil and gas "commercial reserves" in Indonesia as of March 31, 2019, based on Wood Mackenzie's procedures for reserves categorization. We are also the largest exploration and production player in Indonesia, hold more total blocks and active blocks than any other entity in Indonesia, and have the largest net acreage of all oil and gas companies in Indonesia, according to Wood Mackenzie.

We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 919.2 mboe/d in the three months ended March 31, 2019. We also have significant geothermal resources and an extensive distribution network of gas pipelines. Our geothermal installed capacity was 617 MW as of March 31, 2019. We have a portfolio of six refineries with total refining capacity of 1,031.0 mbbls/d and significant downstream assets and infrastructure, including fuel stations, fuel terminals, LPG filling plants, aviation fuel depots, lube oil blending plants, tankers and CNG refueling stations.

For the years ended December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we had total sales and other operating revenue of US$39,811.9 million, US$46,000.7 million, US$57,933.6 million and US$12,670.2 million, respectively. For the years ended December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we had profit after the effect of merging

entity's income adjustment of US$3,471.2 million, US$2,700.4 million, US$2,716.4 million and US$573.4 million, respectively. For a detailed discussion of our results of operations for these periods, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations."

Business Strengths

The Only Fully Integrated Indonesian Oil and Gas Company

We are the only fully integrated Indonesian oil and gas company, and we have a leading market position in both the Indonesian upstream and downstream markets, providing for full integration across the oil and gas value chain.

Leading upstream oil and gas player in Indonesia. We have the largest base of oil and gas "commercial reserves" in Indonesia as of March 31, 2019, based on Wood Mackenzie's procedures for reserves categorization. As of March 31, 2019, our total net proved oil and gas reserves were an estimated 2,126.3 mmboe and our total net proved plus probable oil and gas reserves were an estimated 2,692.2 mmboe. We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 919.2 mboe/d in the three months ended March 31, 2019. We are also the largest exploration and production player in Indonesia, hold more total blocks and active blocks than any other entity in Indonesia, and have the largest net acreage of all oil and gas companies in Indonesia, according to Wood Mackenzie.

Dominant oil refining, marketing and trading company in Indonesia. Our comprehensive downstream portfolio significantly complements our upstream strengths. We are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia. Our total production capacity of 1,031.0 mbbls/d in 2018 comprised nearly all of Indonesia's total refining capacity of 1.1 mmbbls/d, based on Wood Mackenzie data. We have extensive downstream infrastructure and an extensive distribution network in Indonesia, which are comprised of pipelines, fuel stations and depots, and shipping vessels. We currently enjoy a 66% market share of the domestic fuel storage market, owning 5.5 billion liters of capacity, and the vast majority of Indonesia's more than 7,000 retail fuel filling stations are Pertamina-branded, according to Wood Mackenzie. We also have a strong presence in the transportation, marketing and distribution markets in Indonesia.

Strategically Positioned in a Fast Growing Domestic Energy Market

Energy demand in Indonesia is projected to increase from 215 million mtoe in 2018 to 255 million mtoe by 2023, representing a CAGR of 3.5%, largely driven by the robust growth of the power sector, according to Wood Mackenzie. Indonesia is currently a net importer of crude oil and refined products, and to meet the escalating demand, based on current domestic output capacity, oil imports are expected to grow significantly. At the same time, the Government has stated its intention to decrease oil imports. We see this as a significant opportunity for growth, which we intend to meet by increasing our oil and gas production capabilities through upstream expansions and acquisitions as well as expanding our refining capacity through upgrades to existing refineries and constructing new refineries.

In particular, gas demand in Indonesia is expected to increase by 0.8 bcfd from 3.3 bcfd in 2018 to 4.1 bcfd in 2023, with around 33% of Indonesia's gas demand being met by LNG by 2023, according to Wood Mackenzie. Gas production is forecast to remain stable through 2019 following a decline in production in 2018 and is expected to remain at 6.6 bcfd on average until it begins to decline in 2023,

according to Wood Mackenzie. West Java and North Sumatra are expected to continue to face supply constraints due to a decline in existing piped gas supply and are expected to increasingly rely on LNG volumes to meet their gas demands, according to Wood Mackenzie. Several gas-fired power plant projects are also expected to be commissioned within the next five years, which we believe will provide strong growth on the demand side. This shortfall can be remedied by pipeline gas and LNG from Sumatra and Kalimantan, areas where we own large acreage and reserves, and where our sizable gas fields in South Sumatra (Pagar Dewa), West Java (Cirebon) and East Java (Cepu) are located.

Indonesia's GDP (at 2010 constant prices) grew at a CAGR of 5.1% between 2012 to 2017 to reach US$1.1 trillion in 2017, according to the World Bank. Indonesia is poised for robust long-term growth with its expanding working age population and relatively competitive cost environment for businesses, according to Wood Mackenzie. Wood Mackenzie expects Indonesia's GDP to grow from US$1,146 billion (at 2010 constant prices) in 2018 to US$1,449 billion by 2023, a CAGR of 4.7%, supported by an increase of 13 million in population size from the population of 267 million in 2018. Currently, a large proportion of Indonesians reside in rural areas and remain unconnected to the power grid, according to Wood Mackenzie. Wood Mackenzie expects that as urbanization continues and power grid connectivity improves, demand for other solid fuels such as non-commercial biomass will decrease from 26% of total energy demand in 2018 to 23% by 2023, while Indonesian coal will grow from 23% of total energy demand in 2018 to 27% in 2023 driven by increasing supply and cost competitiveness.

Based on our presence across Indonesia and our reserves base, we are strategically positioned to meet expected growth in demand.

Sustained Growth from Significant Reserves, Extensive Downstream Infrastructure Network and Proven Operating Track Record

We have the largest base of oil and gas "commercial reserves" in Indonesia as of March 31, 2019, based on Wood Mackenzie's procedures for reserves categorization. We had estimated total net proved oil and gas reserves of 2,126.3 mmboe and estimated total net proved plus probable oil and gas reserves of 2,692.2 mmboe, as of March 31, 2019. We make new reserve discoveries on an ongoing basis which we believe provides strong reserve replacement and that our portfolio not only provides for production longevity but also serves as a solid foundation for production growth. We expect that our production growth potential in Indonesia will be primarily driven by oil development projects in Cepu, Mahakam and Rokan, gas development projects in Mahakam, Sumatra and Java, strategic domestic acquisitions and enhanced oil recovery projects at existing mature oil fields. Internationally, we successfully completed the acquisition of 72.7% of the share capital of and at least 71.4% of the voting rights in Etablissements Maurel et Prom in February 2017 and through our majority shareholding, and we expect to leverage our international operations in 11 countries towards our aim of securing national energy. In addition, we have an estimated 1,365 MW of proved plus probable geothermal reserves as of March 31, 2019, which we expect to drive significant increases in our geothermal production.

We have maintained our leading position in the oil refining, marketing and trading sectors in Indonesia, notwithstanding recent Government initiatives to liberalize the downstream sector, due to our extensive distribution network and supporting infrastructure. We believe that this gives us a substantial advantage over both our domestic and international competitors. For example, we are currently the largest refiner in Southeast Asia by refining capacity and we are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia, according to Wood Mackenzie. We intend to expand our refining design capacity to 2,000 mbbls/d by the end of 2030, a growth of approximately 94.0% from 2018, and to increase the number of fuel stations owned and operated by us.

We have over 60 years of operational history, and our management team and staff have a proven track record and extensive expertise in operational, engineering, technological, commercial, and financial matters. Our long operating history in the region has given us a level of institutional knowledge of and experience in the Indonesian market that is difficult for our competitors, international or domestic, to match. Our management has also gained significant expertise and knowledge through our 47-year history of strategic alliances and partnerships with major international oil and gas companies such as ExxonMobil, Shell and BP.

Robust Financial Profile

We have robust cash generating abilities, which have supported our operating margins and allowed us to achieve strong financial ratios. We have generated Adjusted EBITDA levels of over US$5.0 billion (with Adjusted EBITDA of US$9.2 billion in 2018) in each of the last three years, and our Adjusted EBITDA levels have generally been healthy despite recent volatility in oil and gas prices. Our stable and strong cash flows are based on long-term contracts for the sale of oil, gas and refined products as well as steam and electricity to a diverse group of domestic and multinational customers, including Mitsui Oil and Mitsubishi. For future offtake contracts, we expect to benefit from a strong and growing customer base for production from our substantial Java and Sumatra assets.

Strong Government Support

As a company wholly owned by the Government, we enjoy strong support from the Government, given the importance of our contribution to domestic revenues and our strategic position in the Indonesian oil and gas sector. We are designated as the Government's oil and gas holding company and the Government's 56.96% shareholding in PGN was transferred to us, making PGN our subsidiary in April 2018. The Government's policy of providing us with a right to request to take over any oil and gas block in Indonesia for which the cooperation contract has expired also allows us to significantly expand our portfolio of domestic upstream assets and to take on attractive new opportunities. We are also entitled to a transition period from oil and gas contractors whose cooperation contracts are scheduled to expire. For example, we were selected as the administrator of the Mahakam Block beginning early 2018 after the existing administrator's contract expired in December 2017. We have also been selected to manage eight oil and gas working areas where the cooperation contracts expired in 2018. We believe that our oil and gas PSCs with the Government in general have more favorable terms than PSCs signed by foreign or private domestic oil and gas companies. Under PEP's PSCs, our share of profits before tax is 67.2%, compared to 12% to 33% for oil and 28% to 37% for gas under a typical PSC. In addition, PHE and local-government enterprises may be nominated by the Government to receive a 10% working interest in PSCs after the first plan of development is approved by the Ministry of Energy and Mineral Resources as PHE is the subsidiary of a state-owned enterprise.

Business Strategy

Our goal is to become one of Asia's leading integrated energy companies that is globally competitive with major international energy companies and international and national oil companies. To achieve these goals, our development strategy is based on four parameters.

Safeguard Indonesia's Energy Future — We intend to meet Indonesia's increasing energy needs by becoming one of Asia's leading integrated energy companies

We aim to secure energy resources for Indonesia, to maintain a leading position in our existing core businesses, and to become a leading national oil company in Asia with a dominant position in Indonesia and a growing international footprint. To achieve this goal, we plan to cultivate a diverse portfolio of energy resources that can meet Indonesia's future energy needs.

In our upstream oil and gas business, we plan to pursue strategic acquisitions, joint ventures, major block development projects and other investments, including with respect to assets that are in production or advanced stages of development, which will expand our oil, gas and geothermal business, in Indonesia and internationally and develop our gas infrastructure in Sumatra and Java. See "Business — Pertamina Upstream Business — Upstream Strategy" and "Business — Pertamina Gas Business." We also aim to maintain our existing leadership in our downstream businesses by diversifying and optimizing our refining capabilities, expanding our retail fuel station network and solidifying our market leadership in fuel, gas and petrochemical products distribution in Indonesia. See "Business — Pertamina Downstream Business — Downstream Strategy."

In the long term, we aim to supplement our existing core businesses and become one of Asia's leading integrated energy companies by expanding our new and renewable energy business into biofuels, biorefineries, photovoltaic power plants, coal conversion and geothermal power strengthening our supply and distribution infrastructure and integrating technology into our business, such as cashless payment systems and digitalized predictive refinery maintenance.

Efficiency — We aim to increase our efficiency and optimize our business operations and technological capabilities

We aim for operational excellence in all of our business activities and intend to consistently achieve above-average efficiency metrics across our operational platform. To achieve this objective, we are focusing on our core businesses and restructuring non-core businesses, streamlining our business processes relating to sales of natural gas and LNG to ensure we obtain optimal pricing, optimizing our upstream assets portfolio and oil recovery activities. We launched the Breakthrough Project ("BTP 2017") in 2017 with initiatives focused on improving efficiencies across all our business lines and improving the efficiency of our refineries. We are focused on employing enhanced oil recovery activities to increase efficiency and production from existing fields and reactivating idle fields. We aim to optimize our current producing assets and improve profitability. For more information, see "Business — Pertamina Upstream Business — Upstream Strategy" and "Business — Pertamina Downstream Business — Downstream Strategy." We also have a Research and Technology Centre ("RTC") to serve as an integrated research and development center and to enhance our technological capabilities across our business lines (see "Business — Research and Development").

Corporate Governance and Culture — We place a high priority on having a strong corporate governance system and a results-driven culture

We place a high priority on corporate governance, professionalism, and transparency, and have developed codes of conduct and corporate policies and procedures that are in line with those of our international and public counterparts. For example, in 2017, Kementerian Badan Usaha Milik Negara (Indonesia's Ministry of State Owned Enterprises) recognized us as the best state-owned enterprise for corporate governance, our President Director Massa Manik was recognized as best chief operating officer in the visionary category and our various subsidiaries won awards in the categories of human resources, transformation, strategy development, financial performance. We were also named by BrandFinance in 2018 as one of the most valuable brands in Indonesia. We also aim to develop a strong, results-driven corporate culture that demands the highest performance by our management and employees alike. One of our key strategies for achieving this end is through our wide range of training and education programs for our employees. To further our efforts, we are also recruiting and developing high quality managerial and technical teams, with an emphasis on the development of leadership skills.

Positioning — We intend to become a model and a benchmark for other regional companies

We aim to become the preferred company of our customers, partners and potential employees. We also aim to remain one of the most highly regarded companies in Indonesia, setting a solid benchmark for Indonesian companies and other energy companies and oil and gas companies in Asia. By implementing international best practices, we believe that we can serve as a standard in terms of capabilities, technology, managerial processes, health, safety and environmental standards and good corporate governance.

General Information

Our full legal name is PT Pertamina (Persero). We are a state-owned limited liability company established in Indonesia under Deed of Establishment No. 20 dated September 17, 2003 drawn up before Lenny Janis Ishak, SH, Notary in Jakarta, as approved by the Minister for Justice & Human Rights under its Decision No. C-24025 HT.01.01.TH.2003 on October 9, 2003, which has been registered in the Company Registration Office of Central Jakarta and published in the State Gazette of the Republic of Indonesia No. 93 dated November 21, 2003, Supplemental State Gazette No. 11620. Our principal executive offices are located at Jl. Medan Merdeka Timur 1A, Jakarta 10110, Indonesia. Our telephone number is (+62) 1-500-000.

Overview of the Program

The following overview does not purport to be complete and is taken from and is qualified in its entirety by, the remainder of this Offering Memorandum and, in relation to the terms and conditions of any particular Tranche of Notes, the applicable Pricing Supplement. Words and expressions defined in "Forms of the Notes" and "Description of the Notes" shall have the same meanings in this summary.

Under the Program, the Company may, from time to time, issue Notes denominated in U.S. dollars, Euros or in any other currency, subject to the terms more fully set forth herein. A summary of the terms and conditions of the Program and the Notes appears below. The applicable terms of any Notes will be agreed upon by and between the Company and the relevant Dealer(s) prior to the issue of the Notes and will be set forth in the Description of the Notes endorsed on, or incorporated by reference into, the Notes, as modified and supplemented by the applicable Pricing Supplement attached to, or endorsed on, such Notes, as more fully described under "Forms of Notes" below.

Summary of the Program and Description of the Notes

Company:	PT Pertamina (Persero)
Arrangers:	Deutsche Bank AG, Singapore Branch, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd. and Standard Chartered Bank.
Dealers:	Deutsche Bank AG, Singapore Branch, The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch, Mandiri Securities Pte. Ltd. and Standard Chartered Bank. The Company may issue Notes to persons other than Dealers and may terminate the appointment of any Dealer or appoint new dealers for a particular Series of Notes or for the Program.
Trustee:	The Bank of New York Mellon
Paying Agent(s):	The Bank of New York Mellon, The Bank of New York Mellon, London Branch
Registrar:	The Bank of New York Mellon
Euro Registrar:	The Bank of New York Mellon SA/NV, Luxembourg Branch
Transfer Agent:	The Bank of New York Mellon
Description:	Global Medium Term Note Program
Program Size:	Up to US$10,000,000,000 (or its equivalent in any other currency (the "Program Limit") in aggregate nominal amount of Notes outstanding

	at any one time). The Company may increase the amount of the Program Limit in accordance with the terms of the Program Agreement.
Method of Issue:	The Notes will be issued on a syndicated or non-syndicated basis. The Notes will be issued in series (each, a "Series") having one or more issue dates and on terms otherwise identical (or identical other than in respect of the first payment of interest and their Issue Price), the Notes of each Series being intended to be fungible with all other Notes of that Series. Each Series may be issued in tranches (each, a "Tranche") on the same or different issue dates. The specific terms of each Tranche (which will be completed, where necessary, with the relevant terms and conditions and, save in respect of the issue date, issue price, first payment of interest and nominal amount of the Tranche, will be identical to the terms of other Tranches of the same Series) will be specified in the pricing supplement (the "Pricing Supplement").
Issue Price:	Notes may be issued at their nominal amount or at a discount or premium to their nominal amount. Partly Paid Notes may be issued, the issue price of which will be payable in two or more installments.
Form of Notes:	The Notes may be issued in bearer or registered form, as specified in the applicable Pricing Supplement. Certificates representing the Notes that are registered in the name of a nominee for one or more clearing systems are referred to as "Global Securities." Each Series of Bearer Notes will initially be represented by a Temporary Global Note or a Permanent Global Note which, in each case, will be deposited on the Issue Date with a common depositary for Euroclear, Clearstream or any other agreed clearance system compatible with Euroclear and Clearstream. Interests in a Temporary Global Note will be exchangeable, from the 40th day following the issue date, for either interests in a Permanent Global Note or Definitive Bearer Notes (as indicated in the applicable Pricing Supplement) and in the case of Notes to which the D Rules (as defined below) apply, upon certification of non-U.S. beneficial ownership as required by United States Treasury regulations ("U.S. Treasury Regulations"). Interests in a Permanent Global Note will be exchangeable, unless otherwise specified in the applicable Pricing Supplement, only in the limited circumstances described therein, in whole but not in part for Definitive Bearer Notes, upon written notice to the Trustee. Any interest in a Temporary Global Note or a Permanent Global Note will be transferable only in accordance with the rules and procedures for the time being of Euroclear, Clearstream and/or any other agreed clearance system, as appropriate. Each Series of Registered Notes, which are sold outside the United States in reliance on Regulation S, will, unless otherwise specified in the applicable Pricing Supplement, be represented by an Unrestricted

	Global Security, which will be deposited on or about its Issue Date with a common depositary for, and registered in the name of a nominee, of Euroclear and Clearstream. Unrestricted Global Securities will be exchangeable for Certificated Securities only in the limited circumstances more fully described herein. Any Series of Registered Notes sold in private transactions to QIBs and subject to the transfer restrictions described in "Transfer Restrictions" will, unless otherwise specified in the applicable Pricing Supplement, be represented by a Restricted Global Security, which will be deposited on or about its Issue Date with a custodian for, and registered in the name of a nominee of, DTC. Persons holding beneficial interests in Registered Global Securities will be entitled or required, as the case may be, under the circumstances described in the Indenture, to receive physical delivery of Certificated Securities. Registered Notes initially offered and sold in the United States to Institutional Accredited Investors pursuant to Section 4(a)(2) of the Securities Act or in a transaction otherwise exempt from registration under the Securities Act and subject to the transfer restrictions described in "Transfer Restrictions" will be issued only in definitive registered form and will not be represented by a Global Security. Bearer Notes will not be exchangeable for Registered Notes, and Registered Notes will not be exchangeable for Bearer Notes.
Clearing Systems:	DTC, Clearstream, Euroclear and, in relation to any Tranche, such other clearing system as may be agreed between the Company, the Trustee and the relevant Dealer. See "Global Clearance and Settlement Systems."
Currencies:	Subject to compliance with all relevant laws, regulations and directives, Notes may be issued in any currency agreed between the Company and the relevant Dealer(s).
Maturities:	Subject to compliance with all relevant laws, regulations and directives, any maturity.
Specified Denomination:	Notes will be in such denominations as may be specified in the relevant Pricing Supplement save that (i) in the case of any Notes which are to be admitted to trading on a regulated market within the European Economic Area or offered to the public in an EEA State in circumstances which require the publication of a prospectus under the Prospectus Directive, the minimum specified denomination shall be US$100,000 (or its equivalent in any other currency as of the date of issue of the Notes) or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, the minimum specified denomination shall be US$200,000 (or its equivalent in any other currency as of the date of issue of the Notes); and (ii) unless otherwise permitted by then current laws and regulations, Notes (including Notes denominated in sterling) which have a maturity of less than one year will have a minimum denomination of £100,000 (or its equivalent in other currencies).

Fixed Rate Notes:	Fixed interest will be payable in arrears on the date or dates in each year specified in the relevant Pricing Supplement.
Floating Rate Notes:	Floating Rate Notes will bear interest determined separately for each Series as set out in the Description of the Notes and the relevant Pricing Supplement.
Zero Coupon Notes:	Zero Coupon Notes may be issued at their nominal amount or at a discount to it and will not bear interest.
Dual Currency Notes:	Payments in respect of Dual Currency Notes will be made in such currencies, and based on such rates of exchange as may be specified in the relevant Pricing Supplement.
Index-Linked Notes:	Payments of principal in respect of Index-Linked Redemption Notes or of interest in respect of Index-Linked Interest Notes will be calculated by reference to such index and/or formula as may be specified in the relevant Pricing Supplement.
Interest Periods and Interest Rates:	The length of the interest periods for the Notes and the applicable interest rate or its method of calculation may differ from time to time or be constant for any Series. Notes may have a maximum interest rate, a minimum interest rate, or both. All such information will be set out in the relevant Pricing Supplement.
Redemption:	The relevant Pricing Supplement will specify the basis for calculating the redemption amounts payable. Unless permitted by then current laws and regulations, Notes (including Notes denominated in sterling) which have a maturity of less than one year must have a minimum redemption amount of £100,000 (or its equivalent in other currencies).
Redemption by Installments:	The Pricing Supplement issued in respect of each issue of Notes that are redeemable in two or more installments will set out the dates on which, and the amounts in which, such Notes may be redeemed.
Optional Redemption:	The Pricing Supplement issued in respect of each issue of Notes will state whether such Notes may be redeemed prior to their stated maturity at the option of the Company (either in whole or in part) and/or the Holders, and if so the terms applicable to such redemption.
Redemption upon a Change of Control Triggering Event:	Unless otherwise stated in the relevant Pricing Supplement and unless the Notes are previously redeemed, repurchased and cancelled, the Company will, no later than 30 days following a Change of Control Triggering Event (as defined in the indenture governing the Notes), make an Offer to Purchase (as defined in the Notes of the relevant Series) all outstanding Notes of any Series at a purchase price of 101% of their principal amount, together with accrued and unpaid interest, if any.

Status of Notes:	The Notes will constitute direct, unsubordinated and unsecured obligations of the Company.
Certain Covenants:	Unless otherwise stated in the relevant Pricing Supplement, the Company will agree in the terms and conditions of the Notes of any Series to observe certain covenants, including, among other things, the incurrence of liens, mergers, acquisitions and disposals and certain other covenants. See "Description of the Notes."
Events of Default:	Certain events will permit acceleration of the principal of the Notes (together with all interest and additional amounts accrued and unpaid thereon). These events include default with respect to the payment of principal of, premium, if any, or interest on, the Notes.
Ratings:	Tranches of Notes will be rated or unrated. Where a Tranche of Notes is to be rated, such rating will be specified in the relevant Pricing Supplement. A rating is not a recommendation to buy, sell or hold securities and may be subject to suspension, reduction or withdrawal at any time by the assigning rating agency.
Withholding Tax:	All payments of principal and interest in respect of the Notes will be made free and clear of withholding taxes unless such withholding is required by law. Indonesia currently applies a withholding tax of 20% to payments of interest on the Notes. In respect of any such withholding required by law, the Company will pay additional amounts that will result in receipt by the holders of the Notes of such amounts as would have been received by them had no such withholding been required, subject to customary exceptions, all as described in "Description of the Notes — Taxation."
Selling Restrictions:	There are restrictions on the offer, sale and transfer of the Notes in the United States, Hong Kong, Singapore, Japan, Indonesia, Italy, the European Economic Area and Switzerland (including the public offer selling restriction under the Prospectus Directive (in respect of Notes having a specified denomination of less than US$100,000 or its equivalent in any other currency as of the date of issue of the Notes or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, US$200,000 or its equivalent in any other currency as of the date of issue of the Notes)) and the United Kingdom. See "Plan of Distribution." Bearer Notes will be issued in compliance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(D) for purposes of Section 4701 of the Internal Revenue Code (the "D Rules") unless (i) the relevant Pricing Supplement states that Bearer Notes are issued in compliance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(C) for purposes of Section 4701 of the Internal Revenue Code (the "C Rules") or (ii) Bearer Notes are issued other than in compliance with the D Rules or the C Rules but in circumstances in which the Notes will not constitute "registration

	required obligations" for U.S. federal income tax purposes, which circumstances will be referred to in the relevant Pricing Supplement as a transaction to which the Tax Equity and Fiscal Responsibility Act of 1982 ("TEFRA") is not applicable.
Use of Proceeds:	We intend to use net proceeds from the issue of each Tranche of Notes to finance capital expenditures and for general corporate purposes or as set forth in the Pricing Supplement applicable to such Notes.
Listing:	Application has been made to the SGX-ST for permission to deal in and for the listing of and quotation of any Notes that may be issued pursuant to the Program and which are agreed at or prior to the time of issue thereof to be so listed on the SGX-ST. There is no assurance that an application to the SGX-ST for the listing of the Notes of any Series will be approved. For so long as any Notes are listed on the SGX-ST and the rules of the SGX-ST so require, such Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in any other currency). The Notes may also be listed on such other or further stock exchange(s) as may be agreed between the Company and the relevant Dealer in relation to each Series. Unlisted Notes may also be issued under the Program. The relevant Pricing Supplement will state whether or not the Notes of a Series will be listed on any exchange(s) and, if so, on which exchange(s) the Notes are to be listed.
Governing Law:	The Notes will be governed by, and construed in accordance with, the laws of the State of New York.

Summary Consolidated Financial and Other Data

The summary audited consolidated financial information as of and for the years ended December 31, 2018, 2017 and 2016 have been derived from our audited consolidated financial statements which are included elsewhere in this Offering Memorandum. The summary unaudited interim consolidated financial information as of and for the three-month periods ended March 31, 2019 and 2018 have been derived from our unaudited interim consolidated financial statements included elsewhere in this Offering Memorandum. These financial statements have been prepared on the same basis as our audited consolidated financial statements. Our results for any interim period may not be indicative of our results for the full year or for any other period.

You should read the following summary consolidated financial information in conjunction with our consolidated financial statements and related notes, "Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements," "Presentation of Financial and Other Data," "Selected Consolidated Financial and Other Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Offering Memorandum. Our consolidated financial statements have been prepared and presented in accordance with IFAS, which differs in certain respects from U.S. GAAP. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP."

Consolidated Statement of Profit or Loss and Other Comprehensive Income Data

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Sales and other operating revenues					
Domestic sales of crude oil, natural gas, geothermal energy and oil products	35,841.7	39,788.8	44,742.5	10,714.0	10,318.0
Subsidy reimbursements from the government	2,568.8	3,572.1	5,632.5	1,342.8	1,212.5
Export of crude oil, natural gas and oil products	968.4	1,874.3	3,637.0	747.9	867.3
Marketing fees	(257.5)	25.5	15.4	1.8	2.9
Revenues from other operating activities	690.5	740.1	3,906.2	325.4	269.5
Total sales and other operating revenues	**39,811.9**	**46,000.7**	**57,933.6**	**13,131.9**	**12,670.2**
Costs of sales and other direct costs					
Cost of goods sold	(26,181.0)	(33,175.7)	(42,787.9)	(9,632.0)	(9,013.1)
Upstream production and lifting costs	(3,270.0)	(3,421.2)	(4,386.5)	(1,224.1)	(1,160.9)
Exploration costs	(109.2)	(165.4)	(267.7)	(63.8)	(25.8)
Expenses from other operating activities	(703.5)	(863.0)	(1,272.0)	(300.1)	(377.4)
Total cost of sales and other direct costs	**(30,263.7)**	**(37,625.2)**	**(48,714.1)**	**(11,220.0)**	**(10,577.2)**
Gross profit	**9,548.3**	**8,375.5**	**9,219.5**	**1,911.9**	**2,093.0**
Selling and marketing expenses	(1,339.6)	(1,590.2)	(1,642.8)	(294.2)	(446.0)
General and administrative expenses	(1,509.3)	(1,598.9)	(1,329.9)	(281.2)	(394.8)
Gain (loss) on foreign exchange — net	(57.5)	58.1	19.6	(67.5)	119.9
Finance income	336.6	233.1	256.6	48.0	145.9
Finance costs	(770.5)	(817.7)	(835.2)	(204.4)	(241.5)
Share in net profit of associates and joint venture	18.7	37.9	122.7	124.9	15.8
Other expenses — net	(877.9)	(830.6)	(80.8)	179.9	(98.7)
	(4,199.4)	(4,508.3)	(3,489.9)	(494.5)	(899.3)

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Profit before income tax	**5,348.9**	**3,867.2**	**5,729.6**	**1,417.4**	**1,193.6**
Income tax expense — net	(1,877.6)	(1,166.8)	(3,013.2)	(729.6)	(620.3)
Profit for the period/year after the effect of merging entity's income adjustment	**3,471.2**	**2,700.4**	**2,716.4**	**687.8**	**573.4**
Other Comprehensive (Loss) Income					
Items not to be reclassified to profit or loss in subsequent periods (net of tax)					
Remeasurement of net defined benefit liability	(73.4)	(129.1)	228.5	75.5	(28.7)
Foreign exchange difference from translation of financial statements in foreign currency	14.7	7.1	(79.6)	5.4	36.4
Share of other comprehensive income of associates	1.5	(25.1)	(130.8)	(21.3)	(69.2)
Other comprehensive income (loss), net of tax	**(57.2)**	**(147.1)**	**18.2**	**59.7**	**(61.5)**
Total comprehensive income for the period/ year after the effect of merging entity's income adjustment	**3,414.0**	**2,553.3**	**2,734.6**	**747.5**	**511.9**
Adjustment of merging entity's income:					
Owners of the parent entity	(173.3)	(81.5)	(45.8)	(45.8)	—
Non-controlling interests	(135.2)	(66.2)	(34.6)	(34.6)	—
	(308.6)	**(147.8)**	**(80.4)**	**(80.4)**	**—**
Profit for the period/year before the effect of merging entity's income adjustment attributable to:					
Owners of the parent entity	3,147.0	2,540.2	2,526.8	534.6	519.1
Non-controlling interests	15.6	12.4	109.3	72.8	54.2
	3,162.7	**2,552.6**	**2,636.0**	**607.4**	**573.4**
Adjustment of merging entity's comprehensive income:					
Owners of the parent entity	(177.0)	(80.7)	(42.5)	(42.5)	—
Non-controlling interests	(138.3)	(65.5)	(32.7)	(32.7)	—
	(315.2)	**(146.3)**	**(75.2)**	**(75.2)**	**—**
Total comprehensive income for the period/ year before effect of merging entity's comprehensive income (loss) adjustment attributable to:					
Owners of the parent entity	3,081.5	2,363.3	2,536.6	608.2	120.2
Non-controlling interests	17.2	43.7	122.8	64.0	391.7
	3,098.8	**2,407.0**	**2,659.3**	**672.2**	**511.9**

Consolidated Statement of Financial Position Data

	As of December 31,			As of March 31,
	2016	2017	2018	2019
				(Unaudited)
		(US$ in millions)		
Assets				
Current assets				
Cash and cash equivalents	6,721.6	6,409.8	9,112.3	8,322.1
Restricted cash	122.7	119.7	108.9	109.3
Short-term investments	130.8	249.3	225.2	298.4
Trade receivables				
Related parties	1,422.3	1,095.0	1,297.7	1,537.3
Third parties	1,442.5	1,580.6	1,933.5	2,187.0
Due from the Government — current portion	1,792.5	1,492.6	1,834.3	2,537.7
Other receivables				
Related parties	242.8	255.1	149.2	165.2
Third parties	649.8	620.5	734.3	780.0
Inventories	4,795.0	6,036.1	6,323.2	6,530.2
Prepaid taxes — current portion	567.6	794.3	820.6	499.7
Prepayments and advances	503.4	476.3	535.0	703.1
Other investments	43.2	27.3	80.2	85.1
Total current assets	**18,434.1**	**19,156.6**	**23,154.2**	**23,755.1**
Non-current assets				
Due from the Government — net of current portion	—	663.1	2,924.1	3,029.2
Deferred tax assets	751.5	1,371.1	1,441.9	1,428.8
Long-term investments	3,329.4	2,970.9	2,819.1	2,728.6
Fixed assets	12,156.8	12,439.5	12,859.3	12,640.8
Oil & gas and geothermal properties	16,397.7	18,031.4	18,614.3	18,541.8
Prepaid taxes — net of current portion	1,469.8	829.3	820.3	874.4
Other non-current assets	1,436.9	1,977.5	2,085.3	2,086.5
Total non-current assets	**35,542.0**	**38,282.8**	**41,564.2**	**41,330.1**
Total assets	**53,976.1**	**57,439.4**	**64,718.5**	**65,085.2**
Liabilities and equity				
Short-term liabilities				
Short-term loans	230.3	452.9	4,347.0	3,671.4
Trade payables				
Related parties	118.5	49.3	78.8	53.6
Third parties	3,290.7	3,900.1	3,597.8	3,236.5
Due to the Government — current portion	952.5	1,050.6	1,207.7	1,725.7
Taxes payable				
Income taxes	475.6	308.8	467.6	521.4
Other taxes	251.6	250.5	258.4	299.8
Accrued expenses	1,596.6	2,019.9	2,135.5	2,345.5
Long-term liabilities — current portion	722.2	366.0	420.6	423.3
Other payables				
Related parties	50.9	56.6	54.0	38.8
Third parties	1,026.8	1,121.5	1,203.4	1,429.8
Deferred revenue — current portion	177.5	260.8	202.0	169.8
Total short-term liabilities	**8,893.2**	**9,837.0**	**13,972.9**	**13,915.6**

	As of December 31,			As of March 31,
	2016	2017	2018	2019
		(US$ in millions)		(Unaudited)
Long-term liabilities				
Due to the Government — net of current portion	732.6	780.6	795.1	790.4
Deferred tax liabilities	2,528.5	2,848.2	3,307.4	3,354.9
Long-term liabilities — net of current portion	2,716.9	2,109.8	1,805.3	1,651.9
Bonds payables	9,772.7	10,385.9	11,094.1	11,099.8
Employee benefit liabilities	2,058.7	2,208.2	1,850.4	1,905.2
Provision for decommissioning and site restoration	1,900.1	2,129.3	2,029.7	2,050.2
Deferred revenue — net of current portion	65.7	42.7	74.6	77.3
Other non-current payables	62.9	84.4	178.9	118.1
Total long-term liabilities	**19,838.1**	**20,589.1**	**21,135.5**	**21,047.7**
Total liabilities	**28,731.3**	**30,426.1**	**35,108.4**	**34,963.3**
Equity				
Equity attributable to owners of the parent entity				
Share capital				
Authorized — 600,000,000 (2019 and 2018) and 200,000,000 (2017 and 2016) ordinary shares at par value of Rp. 1,000,000 (full amount) per share,				
Issued and paid up — 171,227,044 shares (2019 and 2018) and 133,090,697 shares (2017 and 2016)	13,417.0	13,417.0	16,191.2	16,191.2
Additional paid-in capital	2.7	2.7	(924.3)	(924.3)
Merging entity's equity	1,801.7	1,804.6	—	—
Government contributed assets pending final clarification of status	1.4	1.4	401.1	401.1
Other equity components	664.6	487.7	607.6	208.6
Retained earnings				
Appropriated	4,631.4	6,871.1	8,796.4	8,796.4
Unappropriated	3,147.0	2,540.2	2,526.8	3,045.9
Total Equity Attributable to Owners of the Parent Entity	**23,666.0**	**25,124.7**	**27,598.7**	**27,718.9**
Non-controlling interest	1,578.8	1,888.5	2,011.3	2,403.0
Total equity	**25,244.8**	**27,013.3**	**29,610.0**	**30,121.9**
Total liabilities and equity	**53,976.1**	**57,439.4**	**64,718.5**	**65,085.2**

Consolidated Statement of Cash Flows Data

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Cash flows from operating activities:					
Cash receipts from customers	42,723.5	40,220.3	48,878.5	12,316.1	11,953.5
Cash receipts from the Government	3,722.3	3,787.9	7,805.7	1,136.9	974.0
Cash receipts from tax restitution	39.5	616.7	185.0	1.9	3.1
Payments to suppliers	(29,211.9)	(29,261.8)	(38,227.6)	(10,055.0)	(8,877.8)
Payments to the Government	(5,173.5)	(7,524.6)	(11,279.6)	(2,337.4)	(2,250.1)
Payments of corporate income taxes	(2,009.0)	(2,100.3)	(2,688.2)	(567.5)	(642.8)
Cash paid to employees and management	(1,321.4)	(1,540.8)	(1,640.9)	(487.4)	(445.2)
Receipts from (placement of) restricted cash	(494.0)	(156.0)	73.1	(18.8)	0
Receipts of interest	115.7	35.6	63.3	20.5	43.8
Net cash generated from operating activities	**8,391.2**	**4,076.9**	**3,169.4**	**9.4**	**758.5**
Cash flows from investing activities:					
Proceeds from disposal of short-term investment	45.8	99.9	198.4	25.1	24.6
Proceeds from disposal of long-term investments	4.6	15.8	—	—	—
Interest received from investments	4.0	18.2	13.8	5.8	1.9
Cash receipts from other investing activities	—	28.7	262.2	84.7	2.1
Proceeds from sale of fixed assets	2.2	0.1	0.2	0.2	0.2
Dividends received from associates	233.6	81.6	214.1	2.3	0
Purchases of fixed assets	(1,012.7)	(981.9)	(1,288.0)	(163.5)	(196.0)
Purchases of oil and gas and geothermal properties	(1,365.1)	(892.0)	(1,482.5)	(257.7)	(421.6)
Placements in long-term investments	(336.5)	(660.0)	(1,062.2)	(22.7)	(26.7)
Placements in short-term investments	(142.8)	(226.3)	(237.6)	(35.4)	(17.2)
Payments for exploration and evaluation assets	(18.4)	(37.2)	(99.5)	(7.8)	(4.6)
Placement of restricted cash	(10.3)	(29.4)	(22.6)	0	0
Addition of participating interest	(23.8)	—	—	—	—
Cash obtained due to change of control	—	203.2	—	—	—
Net cash used in investing activities	**(2,619.4)**	**(2,379.3)**	**(3,503.8)**	**(369.1)**	**(637.4)**
Cash flows from financing activities:					
Proceeds from short-term loans	2,377.3	4,039.5	9,489.2	830.3	1,079.3
Proceeds from bond issuance	—	—	734.4	—	—
Proceeds from long-term loans	1,674.4	1,288.2	255.9	44.4	51.3
Repayments of short-term loans	(4,057.9)	(3,786.7)	(5,583.3)	(830.3)	(1,885.7)
Repayments of long-term loans	(2,248.4)	(2,109.0)	(465.4)	(201.8)	(182.2)
Dividend payments	(554.9)	(867.8)	(585.8)	—	—
Payments of finance costs	(530.8)	(523.1)	(538.5)	(15.9)	(18.1)
Repayments of bonds payables	(139.8)	—	(37.6)	—	—
Receipts from (placement of) restricted cash	0.4	(13.2)	(0.3)	0.1	(0.7)
Net cash generated from (used in) financing activities	**(3,479.6)**	**(1,972.2)**	**3,268.7**	**(173.0)**	**(956.2)**
Net increase (decrease) in cash and cash equivalents	**2,292.3**	**(274.6)**	**2,934.3**	**(532.7)**	**(835.1)**
Effect of exchange rate changes on cash and cash equivalents	20.7	(37.2)	(231.8)	(44.7)	44.9
Cash and cash equivalents at beginning of the year	**4,408.7**	**6,721.6**	**6,409.8**	**6,409.8**	**9,112.3**
Cash and cash equivalents at end of the year	**6,721.6**	**6,409.8**	**9,112.3**	**5,832.5**	**8,322.1**

Segment Results

The following table presents segment revenues and results for our upstream and downstream segments for the periods indicated. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in this Offering Memorandum. Our segment results are derived from our total segment revenues, after deducting total costs of sales and other direct costs, selling and marketing expenses and general and administrative expenses relating to such segments. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview of Segment Results."

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
				(Unaudited)	
			(US$ in millions)		
Total upstream segment revenues	6,272.3	7,966.3	12,552.6	2,795.0	3,022.9
Upstream segment results	2,065.7	3,327.9	5,960.6	1,272.9	1,368.7
Total downstream segment revenues	32,477.7	37,372.7	46,091.3	10,005.7	10,223.2
Downstream segment results	4,176.2	1,282.2	(286.8)	(28.0)	(160.4)

Non-GAAP and Other Financial Data

	As of or for the Years Ended December 31,			As of or for the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
				(Unaudited)	
			(US$ in millions, except ratios and percentages)		
Capital expenditure[1]	3,025.0	5,423.2	4,533.5	303.7	668.8
Interest expense[2]	531.3	564.1	581.0	134.8	169.8
Adjusted EBITDA[3]	8,162.4	7,108.0	9,204.4	2,244.0	2,047.3
Total debt[4]	13,895.5	13,824.2	18,245.5	13,657.8	17,435.8
Total debt/Adjusted EBITDA (times)	1.7	1.9	2.0	6.1[6]	8.5[6]
Adjusted EBITDA/Total sales and other operating revenues (%)	20.5	15.5	15.9	17.1	16.2
Total debt to Total equity (%)	55.0	51.2	61.6	49.2	57.9
Adjusted EBITDA/Interest expense (times)	15.4	12.6	15.8	16.6	12.1
Dividend payout ratio (%)[5]	39.1	27.6	23.1	—	—

Notes:

(1) Capital expenditure is comprised of additions to fixed assets, oil and gas and geothermal properties and long term investments — investments in oil and gas blocks-net. For details of our capital expenditure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of capital expenditure for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
				(Unaudited)	
			(US$ in millions)		
Additions of fixed assets	1,200.7	1,587.6	1,493.2	280.5	174.3
Additions of oil and gas, and geothermal properties	1,812.0	3,835.6	3,040.3	23.2	494.5
Additions of long term investments — investments in oil and gas blocks-net	12.3	—	—	—	—
Capital expenditure	3,025.0	5,423.2	4,533.5	303.7	668.8

(2) Interest expense is comprised of finance costs for short-term loans, long-term loans and bonds. For details of our loans and bonds, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of interest expense for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Finance Costs:					
Short-term loans	13.9	8.5	56.5	2.9	32.6
Long-term loans	183.2	203.0	172.6	46.6	28.4
Bonds	334.2	352.6	351.9	85.3	108.8
Interest expense	531.3	564.1	581.0	134.8	169.8

(3) We calculate Adjusted EBITDA by adding depreciation, depletion and amortization, finance costs and income tax expense — net to profit for the period/year before the effect of merging entity's income adjustment and subtracting finance income, in accordance with BUMN Regulation KEPMEN 100. BUMN Regulation KEPMEN 100 requires adjustment for all finance costs and does not take into account the effects of merging entity's income adjustment, which arise in connection with acquisitions during the year or period. In comparison, our calculations of EBITDA in the past adjusted for interest expense and not accretion expenses related to decommissioning and site restoration or other finance costs and took into account the effects of merging entity's income adjustment. Adjusted EBITDA and the related ratios presented in this Offering Memorandum are therefore not comparable to our previously disclosed EBITDA and related ratios.

Adjusted EBITDA is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP. Adjusted EBITDA is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with IFAS or U.S. GAAP or an alternative to cash flows from operating activities as a measure of liquidity. In addition, Adjusted EBITDA is not a standardized term, hence a direct comparison between companies using such term may not be possible. We have included Adjusted EBITDA because we believe it is an indicative measure of our operating performance and is used by investors and analysts to evaluate companies in our industry. The following table reconciles our net income under IFAS to our definition of Adjusted EBITDA for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Profit for the period/year before the effect of merging entity's income adjustment	3,162.7	2,552.6	2,636.0	607.4	573.4
Adjustments:					
Finance income	(336.6)	(233.1)	(256.6)	(48.0)	(145.9)
Finance costs	770.5	817.7	835.2	204.4	241.5
Income tax expense — net	1,877.6	1,166.8	3,013.2	729.6	620.3
Depreciation, depletion and amortization expense	2,688.2	2,804.0	2,976.6	750.6	758.0
Adjusted EBITDA	8,162.4	7,108.0	9,204.4	2,244.0	2,047.3

(4) Total debt is comprised of short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans and bonds payables. "Two-step loans" is comprised of: (i) the Ulubelu and Lahendong geothermal project loan, (ii) the Lumut Balai geothermal project loan, (iii) the Ngurah Rai Airport refueling facility construction project loan, (iv) the South Sumatera West Java gas transmission pipeline development project loan, and (v) the Domestic Gas market development project loan. For details, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness."

(5) Dividend payout ratios are calculated as dividends paid during the year equivalents in U.S. dollars divided by the previous year's profit for the year before the effect of merging entity's income adjustment. Dividend payout ratio is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP.

Dividend payout ratio is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income, or any other performance measure derived in accordance with IFAS or U.S. GAAP or an alternative to cash flow from operating activities as a measure of liquidity. In addition, dividend payout ratio is not a standardized term, hence a direct comparisons between companies using such a term may not be possible. For details of our dividend payout ratios, see "Risk Factors — Risk relating to our Company — We are subject to the control of the Government and there is no guarantee that they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue." The following table reconciles our net income under IFAS to our definition of dividend payout ratios for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
				(Unaudited)	
	(US$ in millions except percentages)				
Dividend paid during the year/period equivalents in U.S. dollars	554.9	867.8	585.8	—	—
Prior year profit for the period/year before merging entity's income adjustment attributable to owners of the parent entity	1,420.2	3,147.0	2,540.2	—	—
Dividend payout ratio (%)	39.1	27.6	23.1	—	—

(6) Total debt/Adjusted EBITDA ratios for the three-month periods ended March 31, 2018 and 2019 are calculated based on total debt as of such dates and Adjusted EBITDA for the three-month periods then ended. Therefore, they are not comparable to, and are higher than, our total debt/ Adjusted EBITDA ratios for the years ended December 31, 2016, 2017 and 2018, which are calculated using Adjusted EBITDA for the twelve-month periods then ended.

RISK FACTORS

An investment in the Notes involves certain risks. You should carefully consider all of the following factors, in addition to all of the information contained in this Offering Memorandum including the consolidated financial statements included herein and the related notes thereto, prior to investing in the Notes. The factors described below are not the only ones facing our company. Additional factors not presently known to us or that we currently deem immaterial may also impair our business operations. Our business, financial condition, results of operations and prospects could be materially and adversely affected by any of these risks. The trading prices of the Notes could decline due to any of these risks and you may lose all or part of your investment. This Offering Memorandum also contains forward looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including the risks faced by us described below and elsewhere in this Offering Memorandum.

Risks Relating to Our Company

The volatility in the prices of crude oil, natural gas and our refined products and the uncertainty of the market dynamics for oil and gas could adversely affect our business, financial condition, results of operations and prospects.

Our profitability is significantly affected by the prices of, and demand for, crude oil, natural gas and refined products and the difference between the prices received for the crude oil, natural gas and refined products we produce and the costs of exploring for, developing, producing, transporting and selling these products. The international market for crude oil, natural gas and refined products is volatile and therefore subjects us to various risks and uncertainties. In recent years this market has been characterized by significant price fluctuations. For example, the monthly average price of Indonesian Crude Price-Sumatra Light Crude Minas decreased from US$107.20 per barrel in December 2013 to a low of US$27.49 in January 2016, and was US$55.63 per barrel in December 2018 and US$64.78 per barrel in March 2019. The volatility of the market prices of crude oil, natural gas and refined products is subject to a variety of factors beyond our control. These factors, among others, include:

- demand for crude oil, gas and related products;
- international events and circumstances, as well as political developments and instability in petroleum producing regions, such as the Middle East (particularly the Persian Gulf, Iran and Iraq), Latin America (particularly Venezuela), Northern and Western Africa (particularly Libya) and North America (particularly the U.S.);
- the ability of the Organization of Petroleum Exporting Countries and other petroleum-producing nations to set and change production levels and therefore to influence market prices;
- global and regional supply levels and costs of substitute energy sources, such as natural gas, coal, hydroelectric, tidal, wind or solar power;
- domestic and foreign government regulations with respect to oil and energy industries in general and crude oil, natural gas and refined product pricing policies in Indonesia;
- the level and scope of activity of global oil and natural gas exploration and production, global oil and natural gas inventories, oil speculators and other commodity market participants;

- changes to crude oil, natural gas and refined products' pricing policies by competitors and the Government;
- global conflicts or acts of terrorism and/or conflicts or acts of terrorism in petroleum producing regions;
- inflation and the global inflation outlook;
- actions of commodity market participants;
- fluctuations in exchange rates between the U.S. dollar and the Rupiah;
- weather conditions and seasonality; and
- overall global, domestic and regional economic conditions.

The price of energy, and in particular in the price of crude oil, has fluctuated in the recent past, and there can be no assurance that the prices that our assumptions are based on will not change. Prolonged periods of low oil and gas prices could result in our upstream projects being delayed, deferred or cancelled, which in turn may, among other things, harm the viability of such projects and result in the impairment of related assets.

Our sale of refined products and our downstream operations in general may also be affected by volatility in prices and the factors described above. In addition, there can be no assurance that we will be able to sell our refined products at a price that cover our costs of production (including the costs at which we purchase crude oil from our upstream operations or third parties). For example, during periods of peaking oil prices where our costs of production increase, we may not be able to sell our refined products at prices that result in the same profit margins or any profit on such sales, whether due to downstream market factors, various regulatory restrictions on our sales volumes or prices, or otherwise.

For these reasons, volatility and any significant decreases in the price of crude oil and natural gas, or any market or operational developments that increase our costs of lifting crude oil and natural gas from our existing or future operations may have a material adverse effect on our business, financial condition, results of operations and prospects. For further details regarding the effect of crude oil and natural gas prices on our financial results, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operation — Price of Crude Oil, Natural Gas and Refined Products."

We are subject to the control of the Government and there is no guarantee that they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue.

The Government is our sole shareholder and, through its agencies, it is likely to continue to retain control over us. The Government has historically influenced, and is likely to continue to influence, our strategy, operations and management policies. The Government also has the ability to influence and control other Government-related entities we conduct business with. The Government is likely to retain control of us as our sole shareholder, which gives the Government powers with respect to approving matters such as the election and removal of members of our Board of Commissioners and Board of Directors, amendments to our Articles of Association, changes in our capital structure and mergers and acquisitions, consolidation or liquidation. For further details, see "Relationship with the Government."

The Government also has the power to control the amount and timing of dividends payable by us to them as our sole shareholder. We have historically been required to pay dividends to the Government as an estimated amount based on a specified percentage of our distributable profit as shown in our unaudited financial statements in advance of our audited financial statements becoming available. In 2016, 2017 and 2018, we paid aggregate dividends of Rp. 6.8 trillion (US$554.9 million), Rp. 12.1 trillion (US$867.8 million) and Rp. 8.6 trillion (US$585.8 million), respectively, to the Government. For 2016, 2017 and 2018, this represented aggregate dividend payout ratios (calculated as dividends paid during the year equivalents in U.S. dollars divided by the previous year's profit for the year before the effect of merging entity's income adjustment attributable to owners of the parent entity) of 39.1%, 27.6% and 23.1%, respectively. For 2019, the Government is targeting us to pay approximately 30% or less of our projected profits to the Government as dividends. There can be no assurance that if the amount of the dividends payable exceeds the estimate that the Government will return the excess amount paid by us to the Government or that the Government, as our sole shareholder, would not cause us to pay a larger percentage than the estimate. There can also be no assurance that the Government will not require abnormally large dividends in any given year if it is facing a significant deficit, for other reasons or for no reason whatsoever.

We are currently mandated by the Government under the PSO mandate to distribute fuel domestically. Historically, the Government's regulated prices of subsidized fuel products have not been sufficient to meet our costs of producing or importing and distributing for certain fuel products, and we rely on subsidy reimbursements from the Government to address the shortfall between the regulated retail prices and our costs of producing or importing and distributing such fuel. The subsidy reimbursement formula for the distribution of certain of our fuel products have a fixed margin. Even when the cost of crude oil substantially exceeds the price ceiling assumed by the Government, the subsidiary reimbursement formula and the margin may not be revised, and as the regulated retail price of fuel subject to the PSO mandate is fixed by the Government, we are not able to increase the sale price of the products which we distribute under the PSO mandate. In addition, in determining the subsidy reimbursements payable to us in any given month for the distribution of certain subsidized fuel products, the Government's policy is to use Mean of Platts Singapore ("MOPS") from the month immediately prior to the month to which the subsidiary reimbursement claim relates. This lag in the value of MOPS used in the subsidy reimbursement formula may result in the subsidy reimbursements we receive under our PSO mandate being insufficient to cover our costs of distribution and of our raw materials, in months where there is a significant increase in crude oil prices from the previous month. As a result, we may not recover the increased costs of distributing subsidized fuel under our PSO mandate.

We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue. For example, in 2018, the Government took additional action to compensate us for shortfalls between the retail price of certain subsidized fuel products and our subsidy reimbursements for those products, on one hand, and our costs of distributing subsidized fuel under our PSO mandate, on the other hand. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview of Certain Key Line Items — Sales and Other Operating Revenues — Revenues from other operating activities." In addition, we currently anticipate that our planned developments of new refineries in Bontang and Tuban will be eligible for favorable corporate income tax treatment under Regulation of the Minister of Finance Number 150/PMK.010/2018 on Provision of Corporate Income Tax Holiday Facility for investments in pioneer industries.

If crude oil prices exceed the ceiling price assumed by the Government or our transportation, distribution or other costs increase, we may not be able to recover the full costs of distributing subsidized fuel and LPG under the compensation formula and may incur losses as a result. Because the subsidy reimbursement formulas that affect our results of operations in respect of the PSO mandate is fixed by the Government and beyond our control, we cannot assure you that such losses will not occur

in 2019 or for any other future period. This may have a material adverse effect on our financial condition, results of operations or cash flows. See "— We may not be able to pass on increases in costs of our raw materials for products distributed under our PSO or other mandates from the Government or where the prices of such products are fixed on account of requests by the Government," "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — PSO Mandate" and "Indonesian Regulatory Framework."

The Government could further affect us through other actions, such as the renegotiation or nullification of existing concessions and contracts, the imposition of taxes and foreign exchange restrictions, the fixing of a ceiling price for certain of the non-PSO fuels we distribute, requiring that we supply fuel to other Government-owned entities at a discounted rate or through regulatory changes that have an adverse impact on us. We also derive certain benefits from being a Government-owned entity, including a favorable allocation of net crude entitlement under a PSC for our current and future operational blocks, a favorable share of profits before tax under PEP's PSCs, access to two-step loans under which the Government is a co-obligor with us and a right to request to enter into any cooperation contracts which have already expired for any oil and gas blocks in Indonesia. There can be no assurance that the Government will exercise its control and influence to our benefit or continue to allow us to enjoy such benefits.

If we are required to act in the Government's interests and those interests differ from our interests, or if the Government favors the interests of others, or if the Government decides to remove or reduce any of the benefits we currently enjoy from them, such action could have a material adverse effect on our business, financial condition, results of operations and prospects.

In addition, a significant portion of our sales are to related parties that are also owned and controlled by the Government. The Government has the power to control our sales decisions and could require us to continue to sell to third parties that may be less creditworthy or less likely to promptly meet their payment obligations to us. See "— We are exposed to credit risk on our trade receivables."

The amount of working capital we require for our operations is significant and fluctuates. Our operations may be adversely affected if we do not have sufficient working capital to meet our cash and operational requirements, which may occur as a result of delays in the payment of subsidies which we are owed or for any other reasons.

We expend a significant amount of cash in our operations, principally on the import of crude oil and refined products. In particular, one of our principal operating costs is the acquisition of crude oil feedstock for our refineries. Volatility in market prices for crude oil, natural gas and refined products and fluctuations in exchange rates causes our working capital and costs for our operations to be uncertain.

We fund our operations principally through cash flow from operations, short-term working capital facilities (including bank overdrafts, letters of credit and revolving credit facilities) and long-term bank loans. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources." A significant portion of our cash flow from operations is comprised of subsidy payments under our PSO mandate. To receive subsidy payments, we submit a subsidy claim at the beginning of the month for the subsidized fuel distributed during the preceding month. Although we typically receive 95% of the subsidy claim within a month of its submission, there is no mandatory fixed timeframe in which the Government is required to make such subsidy payments to us. There can be no assurance that we will not experience delays in the payment of such subsidies. For more details, see "Business — Pertamina Downstream Business — PSO." If our revenues are insufficient to cover our working capital needs as a result of low crude oil, natural gas or refined

products prices, delays in subsidy payments, operating difficulties, declines in reserves or for any other reason, we may be unable to obtain the working capital necessary to sustain our operations and we may have to seek alternative sources of funding for our operations. We can provide no assurance that we will not experience negative cash flows in the future. If we fail to generate sufficient revenue from our operations, or if we fail to obtain or maintain sufficient cash and banking facilities, we may not have sufficient cash flow to fund our operations and we may not be able to procure alternative sources of funding on satisfactory terms or at all to meet our liquidity requirements.

We may seek to incur additional indebtedness in the future, which could adversely affect our business or financial condition.

We may in the future incur additional indebtedness. As of December 31, 2018 and March 31, 2019, our total debt (comprising short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans, and bonds payables) was US$18,245.5 million and US$17,435.8 million, respectively. We will require a stable cash flow to meet our obligations under our current and anticipated indebtedness, our capital expenditures, and our working capital requirements. If our cash flow from operations were to be significantly reduced for any reason, consequences may include:

- limitations on our ability to satisfy our obligations under the Notes and other debt;
- an increase in our vulnerability to adverse general economic and industry conditions;
- requirements for us to dedicate a substantial portion of our cash flow from operations to servicing and repaying our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate purposes;
- limitations on our flexibility in planning for or reacting to changes in our businesses and the industry in which we operate;
- a competitive disadvantage as compared to our competitors that have less debt;
- limitations on, along with the financial and other restrictive covenants of our existing or future indebtedness, among other things, on our ability to borrow additional funds; and
- an increase in the cost of additional financing.

Our ability to generate sufficient cash to satisfy our outstanding and future debt obligations will depend upon our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control. We anticipate that our operating cash flow will be sufficient to meet our anticipated present requirements for operating expenses and to service our debt obligations as they become due. However, if we are unable to service our indebtedness, we would be forced to adopt an alternative strategy that may include reducing or delaying capital expenditures, selling assets, and restructuring or refinancing our indebtedness. These strategies may not be instituted on satisfactory terms, if at all, and may negatively affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed expenditures, or withstand any continuing or future downturn in our business. Any of these factors could materially and adversely affect our business, financial condition, results of operations, prospects and our ability to satisfy our obligations under the Notes and other debt.

Our operations are subject to significant operating risks and hazards, for which we may not be fully insured.

We are subject to operational risks and hazards that are common among companies in the oil, gas and geothermal industry, including, but not limited to, the following:

- *Exploration and production risks*: risks related to fluctuations in oil, gas and steam production that may be affected by reserve levels, accidents (including losses of life), mechanical difficulties, work stoppages, adverse natural conditions, such as bad weather or natural disasters, as well as the inability to manage unforeseen production costs, pressure or irregularities in geological formations, unexpected drilling conditions and surface cratering;

- *Equipment risks*: risks related to the adequacy and condition of our oil, gas and steam production facilities, our refineries and our equipment, including situations where equipment becomes obsolete, where our equipment fails, or where availability of necessary equipment is poor;

- *Transportation risks*: risks related to the condition of oil and gas pipelines and vulnerability and costs of other modes of transportation, such as oil tankers; and

- *Storage risks*: risks related to the condition of oil and gas storage tanks and other storage facilities and compliance with safety and environmental standards.

Our business is subject to significant risk of fires, explosions, oil spills, well blowouts, leakage, release of toxic fumes, lightning strikes, other natural or geological disasters, deliberate attacks, sabotage, terrorism risks and other unexpected or dangerous conditions that may cause personal injuries or death, property damage, environmental damage and interruption of operations. Such incidents may have an adverse effect on our business, financial condition, results of operations and prospects. For example, in March 2018, an incident involving one of our undersea pipelines from our Lawe-Lawe Terminal in North Penajam Paser to our refinery facility in Balikpapan resulted in a large oil spill in Balikpapan Bay in East Kalimantan, in response to which we undertook various environmental mitigation and recovery efforts and compensated the affected community. In August 2018, we also experienced an oil spill at our fuel terminal in Wayame. These two incidents required us to expend resources, including financial resources and management time, on investigation, compensation, economic and social recovery and environmental and infrastructure repair. In response to the incident at Balikpapan, although responsibility has been placed on a third party, we have conducted pipeline and port assessment studies for asset integrity and are implementing additional monitoring systems. In response to the incident at Wayame, we have conducted re-training programs and additional protocols to mitigate risks of future occurrences. In July 2019, we experienced a "well kick" in the Java Sea near Karawang (West Java) at an offshore platform operated by PHE ONWJ (as defined herein) where a reactivated well is being developed. As of the date of this Offering Memorandum, we are implementing responsive environmental mitigation measures and undertaking recovery efforts in coordination with the government and other key stakeholders, and we are continuing to investigate the incident. Additionally, certain of our operations and facilities are located offshore and subject to additional dangers inherent in marine operations. These dangers include capsizing, sinking, grounding and damage from severe weather conditions, which could also result in injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of our operations.

While we are prepared and our personnel are trained to deal with such hazards, if we are unable to quickly fix any resulting damage, our drilling and production schedules and refining operations could

be materially delayed and our financial condition and results of operation would be materially and adversely impacted. In addition, drilling hazards or environmental damage could increase the cost of operations, and various field operating conditions may adversely affect our production levels from successful wells. These conditions include delays in obtaining Government approvals or consents, shut-in of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to materially and adversely affect revenue and cash flow to varying degrees.

We may be required to implement temporary, unscheduled shutdowns, for example due to equipment breakdowns or human errors. Such unscheduled shutdowns could materially and adversely affect us. For example, unscheduled upstream shutdowns may require us to source additional feedstock from third parties at higher prices and unscheduled downstream shutdowns may lead to a decrease in inventories available for sale.

We are not fully insured against these operating risks and other types of losses, such as those due to acts of war, either because such insurance is not available at commercially acceptable premiums or at all. We are also not insured for the full value of all of our operational assets as our policy is to obtain insurance in an amount to cover the value of certain high-value assets within each operational asset. We may also lose the capital invested in and the anticipated revenue from the affected property. We also do not have a policy of obtaining business interruption insurance as we take the view that our diversified business assets mitigate the impact of any occurrence of a business interruption. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on us.

We do not carry coverage for product liability insurance for the majority of our refined fuel and non-fuel products. We and our operating partners will be required to bear any costs associated with any incidents to the extent that such costs are uninsured or exceed the amount of such insurance. For a description of the insurance we maintain to protect against operating risks and hazards, see “Business — Insurance.”

Our activities in or in connection with certain countries could lead to U.S. Sanctions.

Certain trade and economic sanctions laws and regulations, including, without limitation, those administered and enforced by the U.S. Department of the Treasury’s Office of Foreign Assets Control’s (“OFAC”) and the U.S. Department of State (collectively, “U.S. Sanctions”), may, in certain circumstances, impact our ability to, directly or indirectly, conduct activities or dealings in or with certain countries that are the subject of comprehensive embargoes (collectively, “Sanctioned Countries”), as well as with individuals or entities (collectively, “persons”) that are the target of U.S. Sanctions-related prohibitions and restrictions (collectively, “Sanctioned Parties”). Although we are not currently directly subject to U.S. Sanctions because we are not incorporated in the United States, do not operate in the United States, and do not employ U.S. persons, our international activities may nonetheless expose us to certain penalties (resulting from secondary sanctions, which can apply to non-U.S. persons in certain circumstances) or other risks (such as reputational risks) in the event that we were to engage in significant transactions with Sanctioned Countries or Sanctioned Parties. Accordingly, in conducting our business we are cognizant of U.S. Sanctions’ potential impact. The U.S. may also choose to impose broader sanctions than currently in place, in particular with respect to Iran or Russia. There can be no assurance that the countries in which we currently operate or the persons with whom we conduct business will not at some point become the target of new or expanded U.S. Sanctions, which could therefore expose us to reputational or other risks as the result of potential dealings therewith.

Although we do not currently operate in or expect to receive any revenue from Sanctioned Countries, we are engaged in certain dealings with a Russian counterparty, described below. Russia is

not currently the target of comprehensive U.S. Sanctions, but the U.S. government maintains sectoral sanctions that restrict U.S. persons from engaging in certain types of transactions with OFAC-designated persons as well as certain activities in Russia. As noted above, we are not a U.S. person and do not employ U.S. persons; accordingly, we are not directly subject to these sectoral sanctions. However, we could, in certain circumstances, be exposed to secondary sanctions. For example, the Countering America's Adversaries Through Sanctions Act authorizes the President of the United States to impose secondary sanctions on non-U.S. persons that knowingly make certain investments that directly or indirectly contribute to Russia's ability to construct energy export pipelines, or provide to Russia goods, services, technology, information, or support that could directly and significantly facilitate the maintenance or expansion of the construction, modernization, or repair of energy pipelines.

In November 2017, we established PT Pertamina Rosneft Pengolahan dan Petrokimia, a joint venture with Rosneft, which is the subject of U.S. Sanctions restrictions, in which we hold a 55% interest. The purpose of the joint venture is to construct a grass root refinery and petrochemical complex in the East Java Province of Indonesia. The project is currently in the study phase and is not targeted to be onstream until 2024 or later. Neither this arrangement or project is subject to primary U.S. Sanctions, nor do we believe that it exposes us to secondary sanctions risks under U.S. law, but it is possible that such liability may arise in the future to the extent that the United States or other governments with applicable jurisdiction expand their trade and economic sanctions regimes over this counterparty, activities, or in any other impactful way.

We import LPG through Petredec, a trading company incorporated in Bermuda. We understand that a small percentage of the LPG supplied to us by Petredec is supplied to Petredec by suppliers in Iran. Although we previously requested that Petredec not supply us with Iran-sourced LPG, the terms of our contract with Petredec limit our ability to control these sourcing activities, and we understand that a small percentage (i.e., less than 10% of our imports from Petredec and less than 1% of our total LPG imports) of the LPG we receive from Petredec may be Iranian-origin. Nonetheless, we do not believe these sourcing activities trigger exposure under U.S. Sanctions. As previously noted, we are not a U.S. person and none of our activities or dealings with Petredec involves U.S. persons. Further, we do not believe that any of our fuel import activities would be subject to the discretionary sanctions of the Iran Sanctions Act of 1996, as amended. Finally, none of the proceeds of the offering of Notes issued under the Program will be used to benefit any parties in Iran.

We are subject to audit by SKK MIGAS and/or the Government which may result in claims by them against us.

Under the terms of our cooperation contracts, our subsidiaries who are parties to such contracts are subject to audit by SKK MIGAS (the successor to BPMIGAS) and the Government which may result in claims against us. Claims arising from such audits are discussed between us and SKK MIGAS or the Government if our management does not agree with them. For a discussion relating to the legal validity and enforceability of our cooperation contracts, see "— All of our current production sharing arrangements and cooperation contracts were entered into with BPMIGAS, the predecessor to SKK MIGAS. Although SKK MIGAS has assumed the functions and responsibilities of BPMIGAS and the Indonesian Constitutional Court's decision has provided that all agreements entered into by BPMIGAS should remain valid until their respective expiry dates, our production sharing arrangements and contracts were not formally assigned or novated by legal instrument to SKK MIGAS from BPMIGAS, leading to potential uncertainty as to their legal validity and enforceability."

In addition, the Supreme Audit Agency of Indonesia ("BPK") audits the accounting records and bookkeeping of our subsidiaries that are party to cooperation contracts on behalf of the Government. If BPK makes any claims relating to cost recovery under any cooperation contracts or PSCs and we are required to make settlement of such claims, our liquidity and financial condition could be adversely affected.

We may be unable to accomplish our development plans for our projects on schedule or within our budgeted costs and we are unable to give any assurance that these plans, if completed, will achieve our development aims.

We have in the past pursued and plan to continue to pursue strategic acquisitions, joint ventures and investments, in particular with respect to assets that are in production or advanced stages of development, that will expand our oil, gas and geothermal business, in Indonesia and internationally and develop our gas infrastructure in Sumatra and Java. We also aim to maintain our existing leadership in our downstream businesses by growing and optimizing our refining capabilities, expanding our retail fuel station network and solidifying our market leadership in fuel, gas and petrochemical products distribution in Indonesia. See "Business — Business Strategy" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Expenditures." Our development plans may relate to areas in which we have limited or no prior investment or operational experience, and there can be no assurance that we will be successful in our efforts operating in such areas or that we will able to achieve our aims in the manner anticipated or at all. In such a case, our business, financial condition, results of operations and prospects could be adversely affected.

As part of our ongoing business, we actively seek to collaborate with various international companies and participate in development projects. Such business partnerships and development projects involve many risks, including:

- economic or political risks, including threats specific to a certain country or region, such as terrorism, social unrest or other conflicts;
- the inability to negotiate successfully with partners, governments, local communities, supplies, customers and other third parties;
- the breakdown or failure of plant equipment or processes;
- the inability to obtain required governmental permits and approvals in time;
- work stoppages and other industrial actions by employees or contracts;
- opposition from local communities and special-interest groups;
- engineering and environmental problems;
- construction delays;
- inability to obtain working capital or control capital and operating costs;
- disputes or delays on the part of our joint venture partners, vendors or counterparties; and
- unanticipated cost overruns.

If we experience any of these or other problems, we may not be able to derive income and cash flows from the projects and investments in a timely manner, in the amounts expected or at all.

The budgeted costs for our development plans are estimates only and will not be known until the contracts for such plans are finalized. There can be no assurance that factors outside of our control will not result in cost overruns that will increase the costs of the projects and require us to seek additional financing. Such factors include fluctuations in raw material costs, technical difficulties, unexpected development expenses, delays in the delivery of equipment or materials, adverse weather conditions, labor disputes, shortages or increased competition or market prices for materials, equipment, skilled personnel and labor, natural disasters, accidents, changes in government priorities and policies, changes in market conditions, delays in obtaining the requisite licenses, permits and approvals from the relevant authorities, and other unforeseeable problems and circumstances. In the event that we need to seek additional financing, there can be no assurance that such financing will be offered at all or on terms acceptable to us. Any of these factors could also give rise to delays in development and completion of our projects beyond schedule, which could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are dependent on our joint venture partners and third-party independent contractors in connection with our exploration and production operations and to implement our development programs.

Many of our major projects and operations are conducted through joint ventures. In certain cases, we may have limited influence over and control of the behavior, performance and cost of operations in which we hold an equity interest or contractual interest and hence are dependent on our joint venture partners to implement our development plans and our ability to identify and manage risks may be reduced. Our joint venture partners' business interests or goals may be inconsistent with ours. Additionally, our partners or members of a joint venture or associated companies (including local partners in our international operations) may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project. For example, we own 45% of our Cepu oil and gas block through our subsidiary, PT Pertamina EP Cepu ("PEPC"). Our joint venture partners in the project, two subsidiaries of ExxonMobil, are responsible for operation of the block. As a party to the PSC in respect of the Cepu block, we share in the block's operational risks even though we are not in control of the operation of the Cepu block.

Although we are the operator under substantially all of our production sharing arrangements, we are dependent on independent third-party contractors to undertake specialized tasks such as rig drilling and production optimization in connection with our exploration and production operations.

There is a risk that such counterparties will fail to meet their obligations as specified or underperform on contractual obligations, whether as a result of financial or operational difficulties or otherwise. Our exploration and production operations or development plans at sites affected by such failure may be disrupted for a substantial period of time to allow the terminated contractor to be replaced or for issues faced by or between the joint venture partners to be resolved. Further, should any agreements with such joint venture partners or contractors be terminated, we cannot assure you that a suitable replacement can be found within a reasonable time or at all. Any material failure by our partners or third-party contractors to adequately perform under their contractual obligations may materially and adversely affect our business, financial condition, results of operations and prospects.

We may not be able to consummate future acquisitions, joint ventures or investments. In addition, any acquisitions, joint ventures or investments which we do consummate could adversely affect us.

We have in the past, and expect in the future, to continue to pursue strategic acquisitions, joint ventures and investments that will expand our oil, gas and geothermal businesses and our activity in the oil, gas and geothermal industry generally. In particular, in our upstream business, our strategy is to continue to pursue such strategic acquisitions, joint ventures and investments domestically as well

as internationally. We may not be able to identify or complete additional acquisitions, joint ventures or investments on commercially attractive terms or at all. All our acquisitions, joint ventures and investments also require approvals from the Government in its capacity as our shareholder, and there is no assurance that approvals will be given to the acquisitions, joint ventures or investments that we propose. In the past, the inability to secure the approval of the Government has contributed to our inability to consummate proposed acquisitions, and we may encounter similar challenges in the future.

The oil and gas industry is highly competitive and we face intense competition from other oil and gas companies and energy companies who may bid for the same international oil and gas assets that we seek to acquire or invest in, or compete for participation in the same joint ventures that we seek. Such competitors may have access to greater financial or other resources than we do, or possess more relevant expertise, which may result in our bids for our proposed acquisitions, joint ventures and investments not being successful.

In addition, we may pursue additional acquisitions, joint ventures and investments in areas of the oil, gas and geothermal sector outside of our core businesses, and in new or unfamiliar geographic regions where our knowledge, expertise and experience may be limited. We may not be able to obtain financing to support any such acquisitions, joint ventures and investments on attractive terms or at all. We may also be subject to foreign or domestic regulatory restrictions, which may limit our ability to consummate future acquisitions, joint ventures or investments.

Even if our proposed acquisitions, joint ventures or investments are consummated, we may not realize any anticipated benefits from them. The process of integrating acquired operations, joint venture operations and investments into our existing operations may result in unforeseen difficulties and may require significant financial resources that would otherwise be available for the ongoing development or expansion of our existing operations. In April 2018, the Issuer acquired 56.96% in PGN, a leading integrated natural gas utility in Indonesia. The process of integrating PGN's natural gas distribution and transmission business with our other natural gas operations has required significant management attention and internal resources and unforeseen difficulties may arise. There can be no assurance that our acquisition of PGN will yield its anticipated benefits in the near term or at all. Disputes or disagreements with our joint venture and other strategic partners may also arise, which could adversely affect the relevant joint venture or strategic arrangement.

Future acquisitions, joint ventures and investments could result in the incurrence of additional debt, contingent liabilities and amortization expenses related to goodwill and other intangible assets and increased capital expenditures, interest and other costs, any of which could have a material adverse effect on our financial condition and operating results by reducing our net profit or increasing our total liabilities, or both. Any of these factors could adversely affect our business, financial condition, results of operations or prospects.

We do not have free and clear title to a significant portion of our land assets.

In connection with our conversion into a limited liability company in 2003, among other non-operating assets, land assets (including non-productive assets such as idle land and buildings) were transferred to us and reflected in our opening balance sheet as of September 17, 2003. We do not have free and clear title to nearly half of these land assets by area, as the legal documentation for such land is not in our possession, has expired or is otherwise not in order, or we are not in occupation of the land in question. We are taking steps to obtain the necessary documentation for the land prior to addressing issues relating to the occupation of the land. There can be no assurance that we will be able to obtain the necessary documentation for all or any of the land over which we do not currently hold free and clear title. Under Indonesian land regulations, not being in possession of the necessary documentation for land assets could result in a loss of entitlement to such land. Under Government

Regulation No. 40 of 1996 on *Hak Guna Usaha* (Right to Manage for Agricultural Activities), *Hak Guna Bangunan* (Right to Build on Land) and *Hak Pakai* (Right to Use and/or Collect the Products of Land), if our title over such land was abolished, we would have to clear any fixtures from the land and return it to the state or deemed owner of the land within one year from the date of abolishment of our title. There can also be no assurance that we will be able to regain possession of land which is currently occupied by third parties.

We are exposed to credit risk on our trade receivables.

As of December 31, 2018, we had trade receivables of US$3,231.1 million, 40.2% of which was owed to us by our related parties. Out of this amount, US$381.6 million was owed to us by PT Perusahaan Listrik Negara (Persero) ("PLN") and its subsidiaries, our related party and a Government-owned electricity company, and US$318.1 million was owed to us by the Indonesian Armed Forces and the Ministry of Defense. As of March 31, 2019, we had trade receivables of US$3,724.2 million, 41.3% of which was owed to us by related parties. Out of this amount, US$433.8 million was owed to us by the Indonesian Armed Forces, US$386.0 million was owed to us by PT Garuda Indonesia (Persero) Tbk and US$366.9 million was owed to us by PLN and its subsidiaries, our related party and a Government-owned electricity company.

Our outstanding trade receivables are not covered by credit insurance and we do not require collateral cover for trade receivables from the Government or Government-related entities (although a portion of our trade receivables from unrelated parties are covered by collateral). As of December 31, 2018 and March 31, 2019, we have made a provision for impairment of US$32.7 million and US$33.2 million against trade receivables owed to us by our related parties, respectively, and US$30.7 million and US$7.8 million of our trade receivables owed to us by our related parties, respectively, have been outstanding for over two years. Although we have procedures to monitor and limit exposure to credit risk on our outstanding accounts receivables for unrelated third party entities, there can be no assurance such procedures will effectively limit our credit risk and avoid losses, which could materially adversely affect our financial condition and results of operations.

Furthermore, because the Government is our sole shareholder and the shareholder of our counterparties, we may have limited courses of action against such counterparties. See "— We are subject to the control of the Government and there is no guarantee that they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue."

Our business is capital intensive, and if we are unable to obtain financing on reasonable terms to fund future capital expenditures, we may not be able to implement our development plans.

We require, and will continue to require, substantial capital expenditures for the acquisition, exploration, development and production of oil, gas and geothermal reserves as well for our downstream business. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — Growth Strategy." Our actual capital expenditures (including PGN's) in 2016, 2017, 2018 and in the three-month period ended March 31, 2019 were US$3,025.0 million, US$5,423.2 million, US$4,533.5 million and US$668.8 million, respectively. Our budgeted capital expenditures (including PGN's), which includes amounts budgeted for potential acquisitions and other uncommitted capital expenditures, for 2019 is approximately US$4,200.0 million.

Our ability to obtain required capital on commercially acceptable terms or at all is subject to a variety of uncertainties, including limitations on our ability to incur additional debt, including prospective lenders' evaluations of our creditworthiness, restrictions on incurrence of debt in our existing and anticipated credit facilities, prevailing conditions in the capital markets in which we may

seek to raise funds, and our future results of operations, financial condition and cash flows. If we do not complete our projects to upgrade our existing oil and gas facilities and infrastructure or our other major development projects that we undertake from time to time as scheduled in our project timelines, or if, following completion of these projects, we do not realize a project's anticipated benefits or experience financial losses, we may be constrained in our ability to secure the capital necessary to undertake or to complete future major development projects, including drilling programs and facility and infrastructure upgrades. There can be no assurance that such financing will be available or sufficient to meet our requirements on commercially acceptable terms, or at all. An inability to access sufficient capital for our operations and capital expenditure requirements could adversely affect our business, financial condition, results of operations or prospects.

We are dependent on key personnel as well as the availability of qualified technical personnel.

We are dependent on certain key senior management employees and, in particular, our employees with specialized technical qualifications or expertise. If we lose the services of any of our key executive officers or employees, it could be very difficult to find, relocate and integrate adequate replacement personnel into our operations, which could seriously harm our operations and the growth of our business. We may be unable to retain our employees, for example, if our employees move to companies located abroad or that offer more attractive remuneration or benefits. We also expect our hiring needs to increase as a significant number of our mid- and senior-level managers near retirement age. There can be no assurance that we will be able to hire a sufficient number of replacement employees or that we will be able to successfully and efficiently train such hirees to fill the roles of their predecessors. We are also dependent on attracting qualified technical employees to provide services in relation to certain of our oil, gas and geothermal operations. The media has reported that there are only few people in Indonesia who have sufficient education and training to perform jobs in oil, gas, geothermal fields, refineries and renewable energy in Indonesia. Even if we are able to attract, integrate and retain new qualified technical personnel, it may be on unfavorable terms. If we are unable to retain our current workforce or hire qualified technical personnel in the future, our operations could be adversely affected.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels, potential litigation and additional compliance obligations.

In December 2015, 195 nations adopted the Paris Agreement, and in October 2016, Indonesia ratified the Paris Agreement through Law No. 16 of 2016 on Ratification of the Paris Agreement to the United Nations Framework Convention on Climate Change. The Paris Agreement aims to limit increases in global temperatures to well below two degrees Celsius. As a result, we expect continued and increased attention to climate change and climate-related issues from all parts of society. This attention has led, and we expect it to continue to lead, to additional regulations designed to reduce greenhouse gas emissions. If our greenhouse gas emissions become subject to such regulation that results in increased compliance costs and operational restrictions, our regulatory burden will increase accordingly. Such regulation could also result in lower revenue and, in the long term, potential impairment of certain assets.

The World Bank has also announced plans to stop financing upstream oil and gas projects beginning in 2019. Similarly, according to press reports, other financial institutions also appear to be considering limiting their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for future projects may be adversely impacted. This could also adversely impact our potential partners' ability to finance their portion of costs, either through equity or debt.

Further, in some countries around the world, governments and regulators have filed lawsuits seeking to hold fossil fuel companies liable for costs associated with climate change. If we were to lose

or settle such a lawsuit, this could have a material adverse effect on our business, financial condition, results of operations or prospects.

Increased regulation of greenhouse gas emissions for new and existing projects or for the products we sell could result in additional costs or financial penalties, delayed or cancelled projects, and/or reduced production and reduced demand for hydrocarbons, which could have a material adverse effect on our business, financial condition, results of operations and prospects.

A substantial portion of our workforce is unionized, and we may face labor disruptions that would interfere with our operations.

A substantial number of our employees are unionized. 19 of our labor unions form a federation (*Federasi Serikat Pekerja Pertamina Bersatu*). The rights and responsibilities under our relationship with the unions are formulated in a collective labor agreement (*Perjanijian Kerja Bersama*) entered into between the unions and our Company. Our latest collective agreement with the unions was signed in April 2019 and is valid for two years. While our relationships with the unions have been good and we believe our Company treats our workforce fairly, there can be no assurance that the outcome of our re-negotiations will be positive or that we will remain on good terms with the unions and we may be affected by strikes, lockouts or other significant work stoppages in the future, any of which could adversely affect our business, results of operations and financial condition. See "Business — Employees."

From time to time, we may be involved in legal, regulatory and other proceedings arising out of our operations, and may incur substantial costs arising therefrom.

From time to time we may be involved in legal disputes. These disputes may cause us to incur substantial costs, delays in our development schedule, and the diversion of resources and management's attention, regardless of the outcome. If we were to fail to win these disputes, we could incur substantial losses and face significant liabilities. Further, even if we were to win these disputes, we may incur substantial costs in mounting our defense. We may also be subject to regulatory action in the course of our operations, which may subject us to administrative proceedings and unfavorable decisions that could result in penalties and/ or delayed construction of new logistics facilities. In such cases, our business, financial condition, results of operations, and prospects could be materially and adversely affected.

Our independent auditors have identified certain aspects of our internal controls and operations relevant to financial reporting for remediation or improvement. If we fail to establish or maintain an effective system of internal controls, we may be unable to accurately report our financial results or prevent fraud.

In connection with the annual audits of our consolidated financial statements as of and for the years ended December 31, 2018, 2017 and 2016, we requested that KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited) provide us, from their assessment of our internal controls to determine the nature, extent and timing of audit procedures for the purpose of expressing an opinion on the consolidated financial statements, with management letters identifying, among other matters, aspects of our internal controls relevant to financial reporting that require remediation or improvement, their implications to our consolidated financial statements, and recommendations for remediation or improvement.

The letters issued by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited) in 2017, 2018 and 2019 (collectively, the "Management Letters") identified a

number of aspects of our internal controls and operations relevant to financial reporting which the independent auditors observed and for which the independent auditors recommended remediation or improvement. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Internal Controls Over Financial Reporting."

Although the Management Letters did not constitute comprehensive assessments of our internal controls, the observations they contained imply that in certain respects, our internal controls and recordkeeping procedures could be improved, and it is possible that, had we performed a formal assessment of our internal controls over financial reporting or had our independent auditors performed an audit of the effectiveness of our internal controls relevant to financial reporting, additional weaknesses and deficiencies may have been identified.

Among others, the Management Letters identified issues relating to:

- certain aspects of our income tax and value-added tax reconciliation and calculation procedures;
- various accounting policy gaps and inconsistencies, including inaccuracies in the recording of employees loan balance, fixed assets, asset capitalization and obsolete and slow moving inventory;
- inaccuracies in our estimation, provision, valuation and assessment methods;
- various factors contributing to imprecise oil measurement at certain refineries;
- unreliability of certain oil tank measuring devices and inventory monitoring systems;
- inadequacies in IT protocols, configurations, controls and usage;
- inaccuracies in recording of deferred revenue and eliminations on consolidation; and
- filing and recordkeeping gaps relating to supporting documents for ownership and control of land assets and material spare parts.

We also requested and received from our independent auditors similar management letters identifying, among other matters, aspects of our internal controls relevant to financial reporting that require remediation or improvement, their implications to our consolidated financial statements, and recommendations for remediation or improvement in connection with the annual audits of our consolidated financial statements as of and for the years ended December 31, 2013, 2014 and 2015.

KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited) did not perform an audit or other types of assurance engagements on the effectiveness of internal controls over our financial reporting under auditing standards generally accepted in the United States ("U.S. GAAS") or auditing standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"). They have not assessed the control deficiencies under U.S. GAAS or the auditing standards of the PCAOB and therefore have not evaluated such deficiencies as either significant deficiencies or material weaknesses as defined under U.S. GAAS or the auditing standards of the PCAOB. Certain issues they reported in their management letters are issues related to our internal controls relevant to financial reporting that they identified from their assessment of internal controls to determine the nature, extent and timing of the audit procedures for the purpose of expressing an opinion on the financial statements. The audit procedures were not specifically designed to, and were not required or requested to be specifically able to, detect any ineffectiveness in internal controls relevant to our financial reporting.

Following the identification of the issues raised in the Management Letters, we have taken measures and plan to continue to take measures to remedy these deficiencies. For details of our proposed remedies, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Internal Controls Over Financial Reporting."

However, the implementation of these measures may not fully address these deficiencies in our internal controls, and we cannot conclude that they have been fully remedied. Our failure to correct these issues or our failure to discover and address any other such issues could result in material misstatements and other inaccuracies in our consolidated financial statements. Any material misstatements may require a restatement of our consolidated financial statements, thereby adversely affecting investors' perception of our financial reporting. As a result, our business, financial condition, results of operations and prospects may be materially and adversely affected. Moreover, ineffective internal controls over financial reporting could significantly hinder our ability to prevent fraud.

Ethical misconduct or breaches of applicable laws by our employees could expose us to criminal and civil penalties and be damaging to our reputation.

In May 2017, we adopted a new Code of Conduct which applies to all of our management and employees and defines our commitment to business integrity and compliance with applicable legal requirements and high ethical standards. Ethical misconduct or non-compliance with applicable laws and regulations, including corruption, fraud and competition laws by us or any third party acting on our behalf could expose us and/or our employees to criminal and civil penalties and could be directly or indirectly damaging to our reputation.

We could also be subject to administrative, judicial or arbitration proceedings that could have a material adverse impact on our financial condition and reputation, if we or any third party acting on our behalf violates any other applicable laws or regulations regulating the ethical conduct of businesses, including anti-corruption and anti-bribery legislation.

Disruption to or breaches of our critical information technology ("IT") services or information security systems could adversely affect our operations.

Our activities depend on the reliability and security of our IT systems. Integrity of our IT systems could be compromised due to, for example, technical failure, cyber-attacks such as viruses or other forms of computer intrusion, power or network outages or natural disasters. Cyber threats are constantly evolving. Attacks are becoming more sophisticated with regularly renewed techniques as the digital transformation amplifies exposure to these cyber threats. The adoption of new technologies, such as the Internet of Things or the migration to the cloud, as well as the evolution of architectures for increasingly interconnected systems, are all areas where cyber security is a very important issue.

As a result, our activities and assets could sustain serious damage, services to clients could be interrupted, material intellectual property could be divulged and, in some cases, personal injury, property damage, environmental harm and regulatory violations could occur, potentially having a material adverse effect on our business, financial condition, results of operations and prospects.

Our future performance depends on the successful adoption and deployment of new technologies and new products.

Technology and innovation are important to our efforts to meet energy demands in a competitive way.

There can be no assurance that we will adopt the right technology in our oil and gas operations or continue to develop marketable products, including crude oil product quality levels that comply with EURO V specifications. We operate in environments where advanced technologies can be utilized, and there is always the possibility of unknown or unforeseeable technological failures or environmental and health effects that could harm our reputation, operations or expose us to litigation or sanctions. A number of our production assets have seen normal depreciation with the passage of time and the emergence of new technology. The associated costs of new technology are sometimes underestimated and technological failures may give rise to delays or disruptions to operations. If we are unable to adopt the right technologies and develop the right products, or if we adopt technologies or introduce products that adversely impact the environment or the health of individuals, there could be a material adverse effect on our earnings, cash flows and financial condition.

In addition, we might face delays or incur additional costs in the adoption and deployment of new technologies and products due to, among other things, our inability to obtain approval from our Company's stakeholders, including the Government, in a timely manner or at all or due to changes in the organizational or managerial structure of the Government or our other stakeholders.

Risks Relating to Our Upstream Operations

Our crude oil, natural gas and geothermal reserve estimates involve a degree of uncertainty and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these reserves.

Our crude oil, natural gas and geothermal reserves are estimated by us. Estimates of economically recoverable crude oil, natural gas and geothermal reserves are based upon a number of factors and assumptions, such as geological and engineering estimates and judgments (which have inherent uncertainties), the assumed effects of governmental regulation and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are therefore, to some degree, speculative and classifications of reserves are always subject to a degree of uncertainty. Many of our reserves estimates have not been certified by third parties, and any certifications that have been obtained may not have been updated recently or at all.

The uncertainties inherent in estimating quantities of proved and probable reserves are numerous and many are beyond our control. One of these uncertainties relates to the physical characteristics of crude oil and natural gas fields. These physical characteristics, including the proportion of discovered resources that can ultimately be produced, the rate of production and the costs of developing the fields, are difficult to estimate and, as a result, actual production may be materially different from current estimates of discovered resources. Other factors affecting our discovered resource estimates include new production or drilling activities, field reviews, the addition of new discovered resources from discoveries or extensions of existing fields, the application of improved recovery techniques and changed economic conditions. Failure to replace or maintain discovered resources levels could result in lower future production, cash flows and income. For these reasons, estimates of the economically recoverable crude oil, natural gas and geothermal reserves attributable to any particular group of properties and the classification of such reserves based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

The reserves data in this Offering Memorandum represents estimates we have prepared based on our oil and gas and geothermal resource management system, which contains procedures for classifying and estimating reserves. In this Offering Memorandum, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007, and estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner

consistent with PRMS 2007. Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves. For more information, see "Presentation of Financial and Other Information — Oil and Gas Reserves."

Estimates of reserves are largely dependent on the quantity and quality of technical and economic data and, in particular, on the interpretation of data obtained from drilling, testing and production and may prove to be incorrect over time. An estimate of reserves is based in part on a field's long-term development plan, and reserves are classified or adjusted and re-classified as contingent where a long-term development plan is not available or up-to-date.

A variety of factors that are beyond our control could require estimates of our reserves to be adjusted downward in the future, or cause our actual production to be lower than its currently reported proved reserves indicate. Such factors include:

- a prolonged period of low prices of oil or gas, making reserves no longer economically viable to exploit and therefore not classifiable as proved;
- an increase in the price of oil or gas, which may reduce the reserves to which we may be entitled under our contractual terms and arrangements with third parties;
- changes in tax rules and other regulations that make reserves no longer economically viable to exploit; and
- the actual production performance of our oil and gas reserves.

Any downward adjustment to our reserves estimates could indicate lower future production amounts, which could adversely affect our financial condition, including our operating income and cash flow.

Estimates of proved and probable reserves that may be developed and produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs, rather than upon actual production history. Subsequent evaluation of the same reservoirs based upon production history may result in revisions to the estimated proved and probable reserves. No assurance can be given that the reserve estimates presented in this Offering Memorandum will be recovered at the levels presented.

The quantities of crude oil, natural gas and geothermal energy that are ultimately recovered could be materially different from our reserve estimates, and downward revisions or reclassifications of our estimates could affect our results of operations and business plan. Published reserves estimates may also be subject to correction due to changes in published rules and guidance. We can give no assurance that the reserves estimates upon which we have made investment decisions accurately reflect actual reserve levels, or even if accurate, that technical limitations will not prevent us from retrieving these reserves.

For a discussion of how we estimate our reserves, including how we define "proved reserves" and "probable reserves" and some differences between our reporting system and the SEC regulations, see "Business — Pertamina Upstream Business — Reserves."

We are dependent on our ability to develop existing reserves, replace existing reserves and develop additional reserves.

We must continually find, acquire, explore for and develop new reserves to replace those produced and sold. We face challenges in sustaining production due to the maturation and depletion of oil and gas properties. Therefore, our future success is dependent upon our ability to develop our reserves and explore, develop and produce additional reserves from existing blocks, to explore and develop alternative sources of fuel such as shale gas and coal bed methane, and to enhance our oil reserves through oil recovery activities or new acquisitions in order to maintain or increase our current levels of production. See "Business — Pertamina Upstream Business — Exploration and Development" for further information on our exploration and development plans and oil recovery activities.

Drilling activities are subject to numerous risks, including the risk that no commercially viable oil or natural gas accumulations will be discovered. The decision to explore or develop a property will depend in part on geophysical and geological analyses and engineering studies, the results of which may be inconclusive or subject to varying interpretations. The cost of drilling, well completion (which includes post-drilling activities such as installing production equipment) and operating wells is often uncertain. Drilling may be curtailed, delayed or cancelled as a result of many factors, including weather conditions, Government requirements and contractual conditions, shortages of or delays in obtaining equipment, reductions in product prices or limitations in the market for products. Wells may be shut in for, among other things, lack of a market or due to inadequacy or unavailability of pipeline or storage capacity. Geological uncertainties and unusual or unexpected formations and pressures may result in dry holes and wells that are productive but do not produce sufficient revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or the recovery of drilling, completion or operating costs.

We plan to increase our activity in exploring and developing our geothermal reserves. The development of such projects is also subject to various uncertainties, such as potential dry holes, flow-constrained wells, and uncontrolled releases of pressure and temperature decline. In addition, the high temperature and high pressure in geothermal energy resources requires special resource management and monitoring. The viability of geothermal projects depends on different factors directly related to the geothermal resource, such as the heat content (i.e. the relevant composition of temperature and pressure) of the geothermal resource, the useful life of the resource and operational factors relating to the extraction of geothermal fluids. Although we believe any geothermal resources will be fully renewable if managed appropriately, the geothermal resources that we intend to exploit may not be sufficient for sustained generation of the anticipated electrical power capacity over time.

In addition, we face substantial competition in the search for and acquisition of reserves and such searches and acquisitions require substantial investment. The possibility of finding or being able to acquire such additional reserves is uncertain. If we are unable to find or acquire and develop additional reserves, we will not be able to sustain our production and grow our business, which would have a material adverse effect on our financial condition and results of operation.

Our upstream operations and development plans may be adversely affected by competition.

As is the case with all international oil, gas and geothermal companies, we face intense competition in our business activities, both domestically and internationally. As a result of the Government's policy to increase competition in the Indonesian oil and gas sector and in connection

with our plans to continue to expand internationally, we expect to face increasing competition with much larger, well-established companies with substantially greater financial, human, technical and other resources. These competitors have strong market power through a combination of different factors, such as diversification and reduction of risk, well-established infrastructure, financial strength, exploitation of benefits of integration and economic scale, strengthening of their positions in the global market and their relations with the governments of oil and gas producing countries.

In addition, other competitive sources may come into operation in the future, and the development of unconventional resources and alternative energy sources may create competition for the conventional Indonesian oil and gas industry. In particular, the growth of the electric vehicle industry may adversely affect demand for our products in the long term.

Many of our competitors have greater financial capacity to fund bids for or acquisitions of oil and gas properties and conduct oil and gas exploration, development and production than us, and may be able to identify, bid for and purchase a greater number of properties and prospects, including operatorships and licenses, than our financial or human resources permit. Accordingly, we expect competition in the oil and gas sector to increase, which could have a material adverse effect on our business, financial condition, results of operations and prospects. See "Business — Competition."

Our exploration and production activities in foreign countries subject us to unforeseen risks.

To increase our oil and gas reserves and diversify our exploration and production operations, we have expanded our investment base to focus on oil and gas exploration and production activities in a number of foreign countries in Southeast Asia, the Middle East and Africa. In addition, we expect to continue to expand our international operations in the future. These international operations are subject to special risks that can materially affect our results of operations. These risks include:

- unsettled political conditions, war, civil unrest, and hostilities in some gas or petroleum producing and consuming countries and regions where we operate or seek to operate, such as in the Middle East and Africa;
- piracy in international waters;
- undeveloped or unexpected developments in legal and regulatory systems;
- exposure to economic instability in foreign markets;
- imposition or increase of withholding and other taxes on remittances by foreign subsidiaries;
- imposition or increase of investment and other restrictions by foreign governments;
- fluctuations and changes in currency exchange rates;
- governmental action such as expropriation of assets, general legislative and regulatory environment, and exchange controls; and
- changes in global trade policies such as trade restrictions and embargoes imposed by the United States and other countries.

Furthermore, investing in or transactions otherwise relating to certain countries (including Sudan and Iran) could also result in adverse consequences to us under existing or future trade or investment sanctions. The effect of any such sanctions would depend on their nature, but if sanctions were imposed on us, or one of our subsidiaries or associated companies, it could affect the market for the securities of that company or impair our ability to access the U.S. capital markets. See "— Risks Relating to Our Company — Our activities in or in connection with certain countries could lead to U.S. Sanctions."

In addition, antitrust, anti-bribery, anti-corruption, data protection and other laws apply to us and our joint ventures and associates in the vast majority of countries in which we operate. Failure to comply with these laws could expose us to regulatory investigations which may result in fines and penalties. Violation of these laws is also a criminal offense in certain countries, and individuals may either be imprisoned or fined. Furthermore, any violation by us of applicable and relevant international sanctions, anti-bribery and anti-corruption legislation could have a material adverse effect on our reputation, business, financial condition, results of operation or prospects.

We cannot predict the effect that the current conditions affecting various foreign economies or future changes in economic or political conditions abroad could have on the economics of conducting exploration and production activities in these markets. Any of the foregoing factors may have a material adverse effect on our international operations and, therefore, could adversely affect our business, financial condition, results of operations or prospects.

All of our current production sharing arrangements and cooperation contracts were entered into with BPMIGAS, the predecessor to SKK MIGAS. Although SKK MIGAS has assumed the functions and responsibilities of BPMIGAS and the Indonesian Constitutional Court has provided that all agreements entered into by BPMIGAS should remain valid until their respective expiry dates, our production sharing arrangements and contracts were not formally assigned or novated by legal instrument to SKK MIGAS from BPMIGAS, leading to potential uncertainty as to their legal validity and enforceability.

SKK MIGAS is an interim body established by the President of Indonesia to replace its predecessor, BPMIGAS, following the dissolution of BPMIGAS by a decision of the Indonesian Constitutional Court on November 13, 2012 and pending the issuance of a new oil and gas law. See "Indonesian Regulatory Framework — Oil and Gas Regulation — Upstream" for more information relating to the dissolution of BPMIGAS. All of our current production sharing arrangements and cooperation contracts were entered into with BPMIGAS prior to its dissolution by the Indonesian Constitutional Court. Although SKK MIGAS has assumed the functions and responsibilities of BPMIGAS and the Indonesian Constitutional Court has provided that all agreements entered into by BPMIGAS should remain valid until their respective expiry dates, our production sharing arrangements and contracts have not been formally assigned or novated by legal instrument to SKK MIGAS from BPMIGAS, leading to potential uncertainty as to their legal validity and enforceability. While the assumption by SKK MIGAS of BPMIGAS's obligations under our production sharing arrangements and cooperation contracts is not, as far as we are aware, subject to any challenge before the Indonesian Constitutional Court or any other Indonesian court, there can be no assurance that we will continue to be able to assert our rights under our production sharing arrangements (including gross split schemes) and cooperation contracts.

Failure or delay by SKK MIGAS, our counterparties or by us to comply with the terms of or renew our production sharing arrangements and cooperation contracts, and the failure to receive SKK MIGAS and other government approvals on a timely basis, could adversely affect us.

SKK MIGAS regulates Indonesia's petroleum resources on behalf of the Government. SKK MIGAS enters (and prior to it, BPMIGAS had entered) into production sharing arrangements and other

forms of cooperation contracts with energy companies (including us and other domestic and foreign private companies) on behalf of the Government, whereby such companies explore, develop and market oil and gas in specified areas in exchange for a percentage interest in the production from the blocks in the applicable contract area. All our reserves in Indonesia are attributable to production sharing arrangements (including gross split schemes) or cooperation contracts.

Our production sharing arrangements (including gross split schemes) and cooperation contracts contain requirements regarding quality of service, capital expenditures, legal status of the contractors and assets, restrictions on the transfer and encumbrance of assets and other restrictions. Any failure to comply with the terms of these production sharing arrangements or cooperation contracts, by us or any private counterparty, could result, under certain circumstances, in the termination of the relevant production sharing arrangement or cooperation contract, which could adversely affect our business, financial condition, results of operations and prospects.

In addition, SKK MIGAS approval is required for substantially all material activities undertaken under these agreements, including exploration, development, production, drilling and other operations, sale of oil or natural gas and the hiring or termination of personnel. The failure to obtain such approvals, or delays in obtaining such approvals, or conditions imposed in connection with the grant of such approvals, could adversely affect us.

Production sharing arrangements (including gross split schemes) and cooperation contracts are valid for a specified period and will need to be renewed following the expiry of such period. We negotiate with SKK MIGAS to renew or extend such arrangements. However, there can be no assurance that we will be able to negotiate new production sharing arrangements or cooperation contracts with SKK MIGAS, or concession or other arrangements with other authorities, when our existing arrangements expire, or that any new arrangements will be on satisfactory terms.

Our business and results of operations are substantially dependent on our relationship with SKK MIGAS and our counterparties, and any adverse change to these relationships could adversely affect our business, financial condition, results of operations or prospects.

We rely on infrastructure and equipment provided by third parties.

As an oil, gas and geothermal exploration and production company, some of the infrastructure that we use to transport oil, gas and geothermal energy to our customers is not owned by us. Such infrastructure, which includes tankers, pipelines and storage tanks, is leased from third-party providers, and we have limited or no control over the quality and availability of this infrastructure. As part of our business, we also have to assume some of the risk of damage or loss of the construction services and equipment provided to us by third-party contractors (such as drilling rigs, seismic acquisition vessels, service boats, tankers and floating storage and offloading vessels). Our development projects have in the past also required us to commit to long-term leases and other financial arrangements.

Limited oil and gas infrastructure in certain parts of Indonesia has to some extent restricted our oil and gas businesses, including our marketing and trading segments. There can be no assurance as to when or if infrastructure capacity will be expanded in areas where it is currently lacking. Construction and upgrading of infrastructure depends on many factors, many of which are beyond our control, such as government funding, costs of land acquisition, national and local government approvals and timely completion of construction.

In addition, we compete with other oil, gas and geothermal companies for equipment and other resources such as oil and gas drilling rigs, distribution vessels, helicopters and aircraft, which are a

limited resource given the competitive market in the Indonesian oil and gas sector. The increased demand for such equipment has resulted in increases in the prices that we have had to pay in order to secure access to such equipment and other resources. If we are unable to obtain the equipment that we need to carry out our development plans with respect to our production assets, we may have to delay or restructure our development plans, which may have an adverse effect on our ability to commercialize our oil, gas and geothermal reserves on a timely basis. Further, depending on the complexity of our development projects, the competitive dynamics of the market, movements in prices of raw materials such as steel, and the availability and prices of contractors and equipment, we may have to pay significantly more than we currently anticipate in order to implement our development plans for our blocks.

From time to time, our production and delivery infrastructure may be interrupted due to logistical complications outside our control, which would adversely affect our ability to sell our products until the problem is corrected or until alternative means can be found. For example, in August 2009, a portion of our Tempino-Plaju pipeline caught fire and, in March 2018, an incident involving one of our undersea pipelines from our Lawe-Lawe Terminal in North Penajam Paser to our refinery facility in Balikpapan resulted in a large oil spill in Balikpapan Bay in East Kalimantan, in response to which we undertook various environmental mitigation and recovery efforts and compensated the affected community. The use of alternative means of crude oil or gas transportation and distribution, if available, would likely result in increased costs, and could adversely affect our business, financial condition, results of operations or prospects.

Risks Relating to Our Midstream Operations

We may not be able to secure additional supplies of natural gas to meet expected demand.

Our natural gas distribution business, which we primarily operate through PGN, is dependent on our ability to obtain natural gas supplies. PGN sources natural gas from PEP and has also entered into long-term natural gas sale and purchase agreements with third parties. The demand and supply imbalance can vary depending on regional markets within Indonesia. We have experienced natural gas undersupply issues in the past, particularly in West Java where a majority of our industrial and commercial customers are located. There can be no assurance that we will be able to put in place the necessary infrastructure and supply contracts to source sufficient supplies of natural gas to service our existing distribution customers, ensure continuity of supply to such customers or expand our natural gas distribution business. If we are unable to source natural gas in volumes sufficient to cover our customers' demand, our business, financial condition and results of operations could be materially and adversely affected.

Our transmission business is dependent on a limited number of significant customers.

We transmit natural gas to a limited number of shippers and off-takers primarily through one of PGN's subsidiaries, PT Transgasindo Indonesia. We enter into gas transportation agreements with a limited number of major customers, and the volume of natural gas we transport is significantly impacted by the off-take volume demand from their respective downstream customers or offtakers. The loss, delay or cancellation of our gas transportation agreements, or renegotiation of terms thereof, as a result of commercial or management decisions or disputes between their respective customers or offtakers and our main customers or offtakers or us, could have a material adverse effect on our business. In addition, if any of our main customers defaults, refuses or is unable to perform its obligations under one of the relevant gas transportation agreements, as a result of financial difficulties or bankruptcy, for instance, our business, financial condition and results of operations could be materially adversely affected.

There is no assurance that we will be able to extend or replace our key natural gas transportation and sale agreements when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. Our ability to extend and replace such agreements could be adversely affected by factors that we cannot control, such as applicable gas transmission and distribution regulations in Indonesia, international and domestic oil and gas prices, timing, volume and location of new market demand, competition from new entrants and/or new energy sources, supply of natural gas in Indonesia, and demand for natural gas in the markets that we serve. If we are unable to renew, extend or replace these agreements or if we renew them on less favorable terms, our cash flows, financial condition and results of operations may be negatively affected.

Risks Relating to Our Downstream Operations

We compete with other oil and gas companies in connection with our downstream operations and for the PSO mandate.

The refining and marketing industry is highly competitive with respect to both feedstock supply and refined product markets. We do not produce all of our crude oil feedstocks and compete with many companies for available supplies of crude oil and other feedstocks. Competitors that have a higher percentage of feedstock from their own production, more complex refineries or more diverse operations may be better able than us to withstand volatile industry conditions, including shortages of crude oil or refined petroleum products, volatility in prices for crude oil or refined petroleum products or intense price competition at the wholesale level. As a result of the Government's policy to increase competition in the Indonesian oil and gas sector, we also expect to come into increasing competition with respect to the distribution of our refined products, including potentially with much larger, well-established companies with substantially greater financial, human, technical and other resources. For example, the Government announced in March 2019 that it has granted a temporary permit to a private company to set up operations to sell aviation fuel, a product that we have previously been the sole provider of in Indonesia. Competition could cause price reductions, reduce our margins or result in loss of market share for our products and services. This may adversely affect our results of operations. See "Business — Competition."

We participate in an annual tender process for the PSO mandate and have been granted a PSO mandate in each of the last three years. In 2017 and 2018 and in the three months ended March 31, 2019, we generated 7.8%, 9.7% and 9.6% of our revenue, respectively, from the distribution of subsidized fuel and LPG. The increase in 2018 was due to an upward adjustment to the subsidy reimbursement formula for automotive diesel oil. If the Government reduces our quota of subsidized fuel under the PSO mandate or withdraws the PSO mandate entirely, we may lose market share in the downstream sector, which could lead to a decrease in the revenue which we generate from the distribution of subsidized fuel and LPG, which may materially and adversely affect our business, financial condition, results of operations and prospects. See "Business — Pertamina Downstream Business — PSO" for more information on our PSO mandate.

We may not be able to pass on increases in costs of our raw materials for products distributed under our PSO or other mandates from the Government or where the prices of such products are fixed at the request of the Government.

We consume large amounts of crude oil and other raw materials to manufacture our refined products and petrochemical products.

We are currently mandated by the Government under the PSO mandate to distribute fuel domestically, and we receive subsidy reimbursements from the Government on the basis of compensation formulae for the distribution of certain of our fuel products. The subsidy reimbursement

amount for automotive diesel oil is subject to a fixed amount set by the Government. The subsidy reimbursement formulas and the margins may not be revised and as the regulated retail prices of subsidized fuel are fixed by the Government, we are not able to increase the sale prices of the subsidized fuel which we distribute.

In addition, in determining the subsidy reimbursements payable to us in any given month for the distribution of subsidized fuel, the Government's policy is to use MOPS for certain products from the month immediately prior to the month to which the subsidy reimbursement claim relates. This lag in the value of MOPS used in the compensation formula may result in the subsidy reimbursements we receive under our PSO mandate being insufficient to cover our costs of distribution, including our costs of our raw materials, in months where there is a significant increase in crude oil prices from the previous month. As a result, we may not recover the increased costs of distributing subsidized fuel under our PSO mandate.

While we try to match the sales prices of our non-subsidized fuel and petrochemical products with corresponding raw material price increases, our ability to pass on cost increases to our customers is dependent on market conditions, commercial considerations and Government regulations. Such commercial considerations include requests from the Government to contract for the sale and purchase of LPG in 12kg cylinders and compressed natural gas ("CNG"), which deprives us of the ability to pass on cost increases which spot prices offer. There may be periods during which increases in costs of raw materials, and hence our costs of distribution, are not fully recovered by us due to an inability to increase the sale prices of our products, which may result in negative margins on distribution and may have a material adverse effect on our financial condition, results of operations or cash flows.

Because the regulated price and subsidy reimbursement formulas that affect our results of operations in respect of the PSO mandate is fixed by the Government and beyond our control, we cannot assure you that losses will not occur in the current year or for any other future period. This may have a material adverse effect on our financial condition, results of operations or cash flows. In 2016, 2017, 2018 and the three-month period ended March 31, 2019, we incurred losses on distribution of the following products: (i) $13.8 million on distribution of kerosene in 2016, (ii) $1,299.0 million on automotive diesel oil (gas oil 0.25% sulfur) fuel and motor gasoline (RON 88) in 2017, (iii) $2,720.0 million on distribution of automotive diesel oil (gas oil 0.25% sulfur), kerosene and motor gasoline (RON 88) in 2018 and (iv) $492.2 million on automotive diesel oil (gas oil 0.25% sulfur) fuel and motor gasoline (RON 88) in 2019. These losses were primarily due to higher costs from rising crude prices. The higher costs could not be passed on to consumers due to the retail price ceilings on subsidized fuel products, nor could they be fully covered by subsidy reimbursements that were set based on lower MOPS from preceding months. See also "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — PSO Mandate" and "Indonesian Regulatory Framework."

The Government also fixes the prices at which we can purchase and sell CNG. As the price set by the Government for CNG sold to us is denominated in U.S. dollars while the price set by the Government for CNG sold by us is denominated in Rupiah, fluctuations in the exchange rate between the U.S. dollar and the Rupiah affect our profit margin from our CNG sales. An adverse change in the value of the Rupiah against the U.S. dollar would decrease our profit margin from our CNG sales, or even result in us making a loss from our CNG sales. The Government may also revise the fixed purchase and sale prices for CNG from time to time and there can be no assurance that we will not incur a loss in our distribution of CNG as a result of any such revisions. To the extent and as long as we are mandated to distribute CNG, we may not be able to cease this activity even if we incur losses in doing so.

If the growth in our production of crude oil lags behind the growth in demand for our refined products and we will be required to source an increasing amount of crude oil and refined products from outside providers.

Our refineries consume very large amounts of crude oil. In 2017 and 2018 and in the three months ended March 31, 2019, approximately 42%, 38% and 23%, respectively, of the crude oil used in our refinery business was sourced from outside suppliers, respectively, while the balance was provided from our own production of crude oil and the Government's share of crude oil produced. This decrease is primarily due to the implementation of Minister of Energy and Mineral Resources Regulation Number 42/2018 in September 2018, which requires us to prioritize the purchase of our crude oil supply from domestic sources. We also import refined products to supplement the refined products which we produce and to meet domestic demand for such products. To the extent that the growth in our production of crude oil lags behind the growth in demand for our refined products, we will be increasingly dependent on third parties for continued access to crude oil and refined products at appropriate prices. If we are unable to obtain adequate crude oil or refined product volumes or are only able to obtain such volumes at unfavorable prices, our margins and other results of operations could be materially adversely affected.

A substantial part of our revenues is derived from the provision of subsidized fuel products.

We are engaged in the provision of fuel products to the public in Indonesia under our PSO mandate, including certain grades of motor gasoline, automotive diesel oil, kerosene and LPG in 3kg cylinders. We receive subsidy reimbursements under our PSO mandate for automotive diesel oil, kerosene and LPG in 3kg cylinders that we sell at regulated retail prices. The Government has historically subsidized the cost of these products and in 2017 and 2018 and in the three months ended March 31, 2019, 7.8%, 9.7% and 9.6% of our total sales and other operating revenues, respectively, came from such subsidy reimbursements. The increase in 2018 was due to an upward adjustment to the subsidy reimbursement formula for automotive diesel oil.

As the regulated retail price for subsidized fuel has historically been lower than our costs to distribute such fuel, we have relied on Government subsidies to partially cover the gap between our costs and revenues. In the past, the manner of calculating and disbursing the PSO subsidy has been amended from time to time. The subsidy payment may be further amended in a manner that is not favorable to us, in addition, future subsidy payments may not be disbursed in a timely manner or at all. The subsidy level itself is subject to adjustments periodically and may be re-evaluated by the Government by considering the realization of numerous factors that may affect the supply and distribution of fuel. Each of these outcomes could have a material and adverse effect on our business, financial condition, results of operations, and prospects.

Efforts by the Government to reduce such subsidies, and the related expenditures has historically been a politically sensitive issue. See "— Risks Relating to Indonesia — Political and social instability in Indonesia may materially and adversely affect us" for a description of instances of public unrest arising from increases in fuel prices and reductions in fuel subsidies. There can be no assurance that Government's current policies relating to fuel subsidies will not be subject to significant changes or influence from public opposition to decreased subsidies or relaxed price controls. Any change in the Government's economic and development policies in these or other respects could have a material and adverse effect on our business, financial condition, results of operations, and prospects.

Due to the limited natural gas transmission and distribution infrastructure, failure by us to develop markets for the sale of our natural gas would have an adverse effect on our results of operations.

The limited natural gas transmission and distribution infrastructure within Indonesia and between Indonesia and other countries has restricted consumption of Indonesian natural gas. There can be no

assurance as to when or if a significant natural gas transmission and distribution system will be constructed. Construction of transmission and distribution pipelines and other infrastructure depends on many factors, many of which are beyond our control, such as government funding, costs of land acquisition, national and local government approvals and timely completion of construction.

Our ability to sustain the planned expansion of our natural gas exploration and production business by continuously finding, developing and maintaining markets for the sale of our natural gas will be subject to many factors, including the ability to obtain funding, regulatory approvals, competition from other regional and international gas producers, downstream market reforms such as reductions of fuel subsidies that could trigger public opposition, environmental regulations, and other operating or commercial risks, some of which are beyond our control. Failure by us to find, develop and maintain markets for the sale of our natural gas would have a material adverse effect on our natural gas business and our business, financial condition, results of operations, and prospects.

Repairs, maintenance and turnarounds at our refineries could affect our results of operations. In addition, due to volatility in the cost of raw materials and finished products in our refining businesses, our regular repair and maintenance operations could occur at an inopportune time when we will be unable to capitalize on high refining margins. The implementation of our plan to comprehensively upgrade our refineries may also limit our existing production during the period in which such upgrading works are being carried out.

We need to carry out regular maintenance at our refineries. Our refineries are typically shut down every three to four years to make necessary repairs, perform preventative and predictive maintenance and implement capital improvements. Such events where entire process units are taken offstream for revamp or renewal ("turnarounds") vary in duration depending on the complexity of the refinery and the work to be performed, but typically last between approximately three to eight weeks. Portions of our refineries may be shut down for shorter periods to perform more limited maintenance and capital improvements. Although we attempt to schedule routine maintenance or overhauls during periods in which our refining margins are low, it is possible that our refineries may be shut down during periods of high margins as a result of, for example, the volatility and unpredictability of refining margins, unscheduled breakdowns, or scheduled turnarounds taking longer to complete than expected.

As our refineries have been in operation for more than 25 years and deploy aging technology, we have adopted a comprehensive plan to upgrade our refineries with the aim to significantly increase their production capacity and complexity. The upgrading of our refineries may require us to shut down critical aspects of our refinery operations for extended periods of time, which may reduce our existing production capacity during the period in which such upgrading works are being carried out. Our upgrading works may also result in unexpected complications to our existing refinery operations, take longer to complete than we expect or not produce the desired increase in the production capacity and complexity of our refineries, all of which would negatively affect our results of operation.

We are dependent on certain key customers which are Government-owned entities and the loss of, or a significant reduction in, purchases by such customers could adversely affect our business. While we aim to diversify our sales to such customers beyond oil products and to increase our sales to non-Government-owned customers, there can be no assurance that we will be successful.

We are dependent on certain key Government-related entities, for a significant portion of our revenues and profits. In 2016, 2017 and 2018 and in the three months ended March 31, 2019, sales to Government related entities accounted for 15.8%, 17.6%, 24.5% and 18.2%, respectively, of our total revenue for the year/period. The loss of, or the reduction, delay or cancellation of supply contracts from these customers as a result of their commercial or management decisions or disputes between us and such customers could have a material adverse effect on our business. For instance, PLN has in

recent years gradually reduced and is expected to continue to reduce its purchases of fuel from us in favor of coal and gas as sources of energy. If any of our Government related entities becomes bankrupt or insolvent, we may also lose some or all of our business from that entity and some of our receivables may be written off, adversely impacting our income and financial condition. Our business is also dependent on the decisions and actions of the Government acting as a shareholder of a Government related entities. The occurrence of any of these events or factors might result in the delay or termination of a project or the loss of a key customer. Because of our current customer portfolio, which includes large Government related entities and government institutions, in the event of major negative externalities, we may have difficulty securing comparable levels of business from non-Government related entities to offset any loss of revenue and profits.

We aim to diversify our sales to our key Government-owned customers beyond oil products to include natural gas and geothermal energy as well and also to increase our sales to non-Government-owned customers to diversify our key customer base, however, there can be no assurance that we will be successful in doing so.

We depend on chartered vessels to distribute our cargo, which subjects us to risks such as potential disruption and/or delay of our sales.

We rely on large tankers and small craft for island-to-island delivery of crude oil and refined products within Indonesia. For a description of our shipping operations, see "Business — Shipping." In 2018, approximately 77.2% of deliveries were made by chartered vessels while approximately 22.8% of deliveries were made by our own vessels. As a result, our costs of distribution depend on the market price for chartering vessels. We generally enter into long-term charter arrangements for vessels. However, we may also rely on the spot charter market, in certain circumstances, to charter vessels to carry specified cargos for single trips. There can be no assurance that such we will be able to successfully implement our plans to increase our fleet of owned vessels and reduce our dependence on chartered vessels, and, accordingly, our reliance on chartered vessels may continue in the future. Volatility and any significant increases in charter rates may have a material adverse effect on our distribution costs and results of operations.

Risks Relating to the Oil, Gas and Geothermal Industry

We are subject to similar industry risks as other oil, gas and geothermal companies operating in Indonesia. Our ability to maintain and develop our business and revenues will be affected by, among other things, the prevailing world prices for oil and Indonesian domestic energy prices for gas as well as other factors, including those discussed below.

The interpretation and application of the Oil and Gas Law of 2001 and the anticipated enactment of a new oil and gas law is uncertain and may adversely affect our business, financial condition, results of operations and prospects.

Indonesia's Oil and Gas Law of 2001 went into effect on November 23, 2001. See "Indonesian Regulatory Framework." This law sets forth general principles to be further implemented through a series of Government regulations, presidential decrees and ministerial decrees, some of which have not yet been promulgated. In general, the provisions of the law are broad, and few sources of interpretive guidance are available. A number of implementing regulations to the Oil and Gas Law of 2001 have been enacted, among others, relating to the formation of SKK MIGAS and its predecessor BPMIGAS (the upstream executive body), and BPH MIGAS (the downstream regulatory body), our conversion into a limited liability state-owned company, and the upstream and downstream industries (including matters with respect to business licensing). SKK MIGAS and BPH MIGAS have enacted some regulations and guidelines that specifically regulate business activities in these sectors. Implementing

regulations have also been issued in respect of, among others, domestic market obligations, field development and reserve production, guidance, procedures, contract terms, designation and tender of working areas, contract amendment and renewal, contractual structures for selling the Government's share of oil and gas and relinquishment of working areas. These regulations are new and subject to interpretation by the regulatory authorities. Pending clear instances of the application of such regulations, it is uncertain how such regulations will affect us.

The uncertainty surrounding the Oil and Gas Law of 2001 has increased the risks, and may result in further increases of the costs, of conducting oil and gas business in Indonesia. For example, the Government enacted Government Regulation No. 55 of 2009 as the second amendment to Government Regulation No. 35 of 2004 on Upstream Oil and Gas Business Activities, which requires contractors to fulfill domestic gas and oil demand by delivering 25% of their share of oil and gas production to the local market, which is known as the domestic market obligations ("DMO"). A gas field discovery must be notified to the Ministry of Energy and Mineral Resources. If the discovery will be produced commercially, the Ministry of Energy and Mineral Resources will allow domestic gas consumers to deliver their gas demands to them in writing within one year from the date the gas field is discovered. Within three months of the expiry of the one year period, the Ministry of Energy and Mineral Resources will notify the contractor of the domestic gas demand condition. If domestic gas demand exists, the contractor shall commence negotiations with the domestic consumer. The contractor may only sell its gas to the international market if there is no domestic gas demand or the contractor fails to reach an agreement with domestic consumer. Prior to selling its gas to international market, the contractor must obtain an export approval from the Minister of Trade, which is based on a recommendation from the Directorate General of Oil and Gas of the Ministry of Energy and Mineral Resources ("DGOG").

Under the Oil and Gas Law of 2001, new cooperation contracts are subject to a broader Government approval process. Negotiation of cooperation contract terms with potential contractors is handled primarily by SKK MIGAS. The relevant work area is awarded by either competitive tender or direct award, and the Indonesian Parliament must be notified of the production sharing arrangements entered into under such cooperation contract. The Government may implement policies regarding oil and gas exploration and production that differ from previous policies.

Not all of the implementing regulations to the Oil and Gas Law of 2001 have been issued and some have only been recently enacted. Accordingly, the full impact of the Oil and Gas Law of 2001, the related implementing regulations and any change in Indonesian oil and gas laws on our financial and operational status cannot be determined at this time. Furthermore, it is anticipated that a new oil and gas law will be enacted in the future, the substance, form and timing of which is uncertain. To the extent the new law or the implementing regulations to the Oil and Gas Law of 2001 or their implementation or interpretation by Indonesian regulatory authorities, courts or SKK MIGAS and BPH MIGAS are adverse to us, our business, financial condition, results of operations and prospects could be materially and adversely affected.

Our compliance with or breach of environmental regulations in Indonesia and in the countries in which we operate could materially and adversely affect our business, financial condition, results of operations and prospects.

We are subject to various environmental laws and regulations concerning land use, air emissions, water discharge, waste materials and abandonment of our wells and other operating structures in connection with the design and operation of our upstream and downstream oil, gas and geothermal facilities in Indonesia and other countries in which we operate, transact business or have interests. Numerous government agencies and departments issue environmental rules and regulations, which are often difficult and costly to comply with and which carry substantial penalties for non-compliance.

We cannot assure you that we will not be in breach of any applicable environmental laws and regulations, be subject to stricter enforcement or interpretation of existing environmental laws and regulations, or that such laws and regulations will not become more stringent in the future. It is possible that any breach or such stricter enforcement may give rise to liabilities which we may have to incur potentially significant costs to remedy arising from the discharge of oil, natural gas or other pollutants into the air, soil or water. For example, in March 2018, an incident involving one of our undersea pipelines from our Lawe-Lawe Terminal in North Penajam Paser to our refinery facility in Balikpapan resulted in a large oil spill in Balikpapan Bay in East Kalimantan, which required us to undertake various environmental mitigation and recovery efforts and to pay compensation fees to the affected community. In August 2018, we also experienced an oil spill at our fuel terminal in Wayame, which gave rise to additional cleanup costs. Similar events may occur in the future and expose us to similar liabilities. In July 2019, we experienced a "well kick" in the Java Sea near Karawang (West Java) at an offshore platform operated by PHE ONWJ (as defined herein) where a reactivated well is being developed. As of the date of this Offering Memorandum, we are implementing responsive environmental mitigation measures and undertaking recovery efforts in coordination with the government and other key stakeholders, and we are continuing to investigate the incident. Such liabilities may have an adverse effect on our business, financial condition, results of operations and prospects.

The environmental management systems that apply to us are EMS ISO 14001 and Environmental Compliance Performance Evaluation Program (*Program Penilaian Peringkat Kinerja Perusahaan dalam Pengelolaan lingkungan*, or "PROPER") administered by the Ministry of Environment and Forestry. The Ministry of Environment and Forestry in Indonesia rates companies in accordance with PROPER, which consists of a series of five ratings ranging from "gold" (the highest possible rating) to "black" (the lowest possible rating). In 2018, two of our operating units that had blue PROPER ratings during the July 2017 to June 2018 appraisal period had received a red PROPER rating, which indicates the units are partially out of compliance due to a lack of monitoring activities at various locations.

On October 3, 2009, Law No. 32 of 2009 on Protection and Management of Environment (the "New Environmental Law") was enacted which required that all current environmental management licenses be integrated into the environmental permit issued pursuant to the New Environmental Law and introduced more stringent penalties for breaches of environmental laws and regulations. On February 23, 2012, the Government enacted Regulation No. 27 of 2012 on Environmental Permit (*Izin Lingkungan*) ("Regulation No. 27") which requires that in addition to an environmental impact analysis (*Analisa Mengenai Dampak Lingkungan*) ("AMDAL") approval, an environmental management effort plan (*Upaya Pengelolaan Lingkungan*) ("UKL") or an environmental monitoring effort plan (*Upaya Pemantauan Lingkungan*) ("UPL"), an environmental permit from the Ministry of Environment and Forestry or governor or mayor/head of regent of their respective areas would need to be obtained. Although all AMDALs, UKLs, and UPLs, existing before the implementation of Regulation No. 27 would be accepted as valid environmental permits, we are currently taking steps to improve our management of sludge and produced water in order to comply with the standards set by the New Environmental Law. However, there can be no assurance that we will be able to do so. Under the New Environmental Law, if obligations in the AMDAL approval or UKL or UPL are not met, one of the sanctions that could be imposed is the revocation of our environmental permit. Revocation of an environmental permit may lead to nullification of our business license which may require us to cease certain operations and have a material adverse effect on our business, financial condition, results of operations and prospects. See "Business — Environmental Matters." The enactment of further implementing regulations relating to the New Environmental Law could cause us to incur significant additional costs or delay in the completion of our projects under development in order to comply with such new regulations.

Given the possibility of unanticipated regulatory or other developments, including more stringent environmental laws and regulations, the amount and timing of future environmental compliance

expenditures could vary substantially from their current levels. These changes could limit the availability of our funds for other purposes. We cannot predict what additional environmental legislation or regulations will be enacted in the future or the potential effects on our business, financial condition, results of operations and prospects.

Increased regulation by governments and governmental agencies may increase the cost of regulatory compliance and limit our access to new exploration properties.

The oil and gas industry is generally subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production contracts, the imposition of specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field (including restrictions on production) and possibly, nationalization, expropriation, cancellation or non-renewal of contract rights.

Within Indonesia, where our operations are primarily located, the evolving roles of SKK MIGAS, BPH MIGAS and the Ministry of Energy and Mineral Resources, coupled with political changes in Indonesia, have allowed other Government agencies such as the Minister of Trade and the Ministry of Environment and Forestry to increase their roles in administering and regulating the oil and gas industry in Indonesia. The continued expansion of the roles of governmental agencies may result in the adoption of new regulations, legislation and practices that we would be required to comply with.

New regulations, legislation and practices may be adopted by the Government and other governments or governmental agencies in countries which we have operations in response to evolving practices or specific incidents, which may result in more stringent regulation of our oil and gas activities, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new areas. Any new regulations, legislation and practices could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships. We buy, sell and trade oil and gas products in certain regulated commodity markets. Failure to respond to changes in trading regulations could result in regulatory action and damage to our reputation.

In addition, regulations and directives of national and local governments with respect to matters such as limitations on production volumes and exports, pricing policies, environmental protection controls, nationalization or privatization of assets, expropriation and cancellation of rights, may affect us. We are directly and/ or indirectly subject to all these risks and to any adverse consequences flowing from these risks as a result of our business activities.

The oil and gas industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and we operate in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

Risks Relating to Indonesia

We are incorporated in Indonesia and a substantial portion of our assets and operations are located in Indonesia. Due to the concentration of our assets and operations in Indonesia, future political, economic, legal and social conditions in the country or region, as well as certain actions and policies that the Government may, or may not, take or adopt could materially and adversely affect our business, financial condition, results of operations and prospects and our ability to make payments under the Notes.

Depreciation and fluctuations in the value of the Rupiah against foreign currencies may materially and adversely affect our financial condition and results of operations.

The Rupiah has experienced significant volatility in the past, particularly during prolonged economic downturns following the global financial crisis in 2007-2008. For example, the Rupiah depreciated from Rp. 12,171 per U.S. dollar as of December 31, 2013 to Rp. 14,390 per U.S. dollar as of December 31, 2018 and from Rp. 11,361 per U.S. dollar as of March 31, 2014 to Rp. 14,243 per U.S. dollar as of March 31, 2019. There can be no assurance that the Rupiah will not further depreciate or volatility will not continue, that the Government's current exchange rate policy will remain the same, or that the Government will, or will be able to, act when necessary to stabilize, maintain or increase the value of the Rupiah, and will not act to devalue the Rupiah, or that any such action, if taken, will be successful.

The Rupiah has generally been freely convertible and transferable (except that Indonesian banks may not transfer Rupiah to persons outside of Indonesia and may not conduct certain transactions with non-residents). However, from time to time, Bank Indonesia has intervened in the currency exchange markets in furtherance of its policies, either by selling Rupiah or by using its foreign currency reserves to purchase Rupiah. There can be no assurance that the current floating exchange rate policy of Bank Indonesia will not be modified or otherwise changed, that additional depreciation of the Rupiah against other currencies, including the U.S. dollar, will not occur, or that the Government will take additional action to stabilize, maintain or increase the value of the Rupiah, or that any of these actions, if taken, will be successful. Modifications of the current floating exchange rate policy could result in significantly higher domestic interest rates, liquidity shortages, capital or exchange controls or the withholding of additional financial assistance by multinational lenders. This could result in a reduction of economic activity, an economic recession or loan defaults, and as a result, we may also face difficulties in implementing our business strategy. Any of the foregoing consequences could have a material adverse effect on our business, financial conditions, results of operations and prospects.

Our payments within Indonesia are made in Rupiah due to compliance with applicable laws in Indonesia requiring payments to be denominated in Rupiah, while most of our operating costs, particularly in relation to the procurement of crude oil and oil products, are incurred and paid in U.S. dollars. Any adverse changes in the value of the Rupiah against the other currencies, including the U.S. dollar, could have a material adverse effect on our financial condition, results of operations or cash flows.

Regional or global economic changes may materially and adversely affect the Indonesian economy and our business.

The regional Southeast Asia and global economies have been adversely affected during prolonged economic downturns, including during the economic crisis that affected Southeast Asia, including Indonesia, from mid-1997 and the global financial crisis in 2007-2008, which was triggered in part by the subprime mortgage crisis in the United States, caused failures of large U.S. financial institutions and rapidly evolved into a global credit crisis. These extremely negative economic developments have adversely affected both developed economies and developing markets, including Indonesia and other Association of Southeast Asian Nations ("ASEAN") countries. Global financial markets have also recently experienced volatility due to political uncertainty following political elections in the U.S. and Western Europe and the 2016 United Kingdom national referendum in which a majority of voters elected to withdraw from the European Union. Uncertainty over the outcome of the Eurozone's government's financial support programs and the stability of the European Union and worries about sovereign finances generally are ongoing.

Indonesia and other ASEAN countries have been negatively affected, along with developing market countries globally, by the weak financial and economic conditions in developed markets.

Although the Government has in the past taken steps to maintain economic stability and public confidence in the Indonesian economy in response to such conditions internationally, any continuation of weak financial and economic conditions in developed markets may negatively impact economic growth, the Government's fiscal position, the Rupiah's exchange rate and other facets of the Indonesian economy.

A loss of investor confidence in the financial systems of emerging or other markets may cause increased volatility in Indonesian financial markets which may, in turn, adversely affect the Indonesian economy in general. Any worldwide financial instability could also have a negative impact on the Indonesian economy, which could have an adverse effect on our business, financial condition, results of operations and prospects. There can be no assurance that the recent improvement in economic conditions will continue or that adverse economic conditions will not recur. Such developments could have a material adverse effect on us and our business, financial condition, results of operations and prospects. Economic instability may also result in a shortage in the availability of credit, a reduction in foreign direct investment, the failure of global financial institutions, a drop in the value of global stock markets, a slowdown in global economic growth and a drop in demand for certain commodities which we produce.

Changes to trade policies, treaties and tariffs in the jurisdictions in which we operate, or the perception that these changes could occur, could adversely affect our international and cross-border operations, our financial condition and results of operations. U.S. President Donald Trump's administration has advocated greater restrictions on trade generally and increases on tariffs on goods imported into the United States, particularly from China. Further, the U.S. or China could impose additional sanctions that could restrict us from doing business directly or indirectly in either country. These or similar actions, or adverse spillover effects of foreign trade policies, treaties or tariffs, could have a material adverse impact on our profitability and operations.

There can be no assurance that any short-term improvement in economic conditions will continue or the previous adverse economic condition in Indonesia and the rest of the Asia-Pacific region will not occur in the future. The current global economic situation could deteriorate or have an impact on Indonesia and our business. Any of the foregoing could materially and adversely affect our business, financial condition, results of operations and prospects, and on our ability to make payments under the Notes.

Political and social instability in Indonesia may materially and adversely affect us.

Political campaigns, elections and other developments in Indonesia have in the past and may continue to bring a degree of political and social uncertainty to Indonesia. Indonesia continues to face various socio-political issues and has, from time to time, experienced political instability and social and civil unrest. Such instances of unrest have highlighted the unpredictable nature of Indonesia's changing political landscape. Indonesia also has many political parties, without any one party winning a clear majority to date. These events have resulted in political instability, as well as general social and civil unrest on certain occasions in recent years.

Indonesia also has a history of demonstrations and social protests concerning Indonesian politics as well as in response to specific issues, including fuel subsidy reductions, privatization of state assets, anticorruption measures, minimum wage, decentralization and provincial autonomy, actions of former Government officials and their family members, potential increases in electricity tariffs, human rights violations and international geopolitical events, such as past U.S. led military campaigns in Afghanistan and Iraq. Although these demonstrations have generally been peaceful, some have turned violent. There can be no assurance demonstrations or protests will not occur in the future or that such events will not adversely affect our business or operations.

Separatist movements and clashes between religious and ethnic groups have resulted in social and civil unrest in parts of Indonesia. Should these events occur in the vicinity of our facilities or transport routes, our business and operations may be adversely affected. Political and social unrest may occur if the results of future elections are disputed or unpopular. Political and social developments in Indonesia have been unpredictable in the past and, as a result, confidence in the Indonesian economy has remained low. Any resurgence of political instability could lead to extended disruptions in our operations and/or adversely affect the Indonesian economy, which could adversely affect our business.

We are particularly susceptible to the risks and consequences of political and social instability because the Government is our sole shareholder. In addition, political and social instability or unrest may give rise to changes in government laws, regulations or policies that have material adverse consequences on us. There can be no assurance that social and civil disturbances will not occur in the future and on a wider scale, or that any such disturbances will not, directly or indirectly, materially and adversely, affect our business, financial condition, results of operations and prospects, and our ability to make payments under the Notes.

Regional autonomy may have a material adverse effect on our business through imposition of local restrictions, taxes and levies.

Indonesia is a large and diverse nation covering a multitude of ethnicities, language, traditions and customs. During the administration of the former President Suharto, the central government controlled and exercised decision-making authority on almost all aspects of national and regional administration, including the allocation of revenues generated from extraction of national resources in the various regions. This led to a demand for greater regional autonomy, in particular with respect to the management of local economic and financial resources. In response to the demand for greater regional autonomy, the Indonesian Parliament in 1999 passed Law No. 22 of 1999 regarding Regional Autonomy ("Law No. 22/1999") and Law No. 25 of 1999 regarding Fiscal Balance Between The Central Government and the Regions ("Law No. 25/1999"). Law No. 22/1999 has been revoked and replaced by the provisions of regional autonomy in Law No. 23 of 2014 on Regional Government ("Law No. 23/2014") which was further amended by Law No. 2 of 2015 on the First Amendment of Law No. 23/2014 and Law No. 9 of 2015 on the Second Amendment of Law No. 23/2014. Law No. 25/1999 has been revoked and replaced by Law No. 33 of 2004 regarding the Fiscal Balance between the Central and the Regional Governments. Under these regional autonomy laws, regional autonomy was expected to give the regions greater powers and responsibilities over the use of "national assets" and to create a balanced and equitable financial relationship between central and local governments. However, certain regional governments have put in place various restrictions, taxes and levies which may differ from restrictions, taxes and levies imposed by other regional governments and/or are in addition to restrictions, taxes and levies stipulated by the central government. Conflicting and/or additional restrictions, taxes and levies that may be imposed by the applicable regional authorities may have a material adverse effect on our business and operations located throughout Indonesia.

It may not be possible for investors to effect service of process or to enforce certain judgments on the Issuer or its management.

The Issuer is a state-owned company established with limited liability in Indonesia. All of the commissioners, directors and executive officers, as applicable, of the Issuer reside outside the United States. Substantially all of the assets of the Issuer and these other persons are located outside the United States. As a result, it may be difficult for investors to effect service of process upon the Issuer or such persons within the United States or other jurisdictions, or to enforce against the Issuer or such persons in such jurisdiction, judgments obtained in courts of that jurisdiction, including judgments predicated upon the civil liability provisions of the federal securities laws of the United States or any state thereof.

We have been advised by our Indonesian legal advisors, UMBRA Partnership, that judgments of non-Indonesian courts are not enforceable in Indonesian courts, although such judgments could be admissible as non-conclusive evidence in a proceeding on the underlying claim in an Indonesian court. There is doubt as to whether Indonesian courts will enter judgments in original actions brought in Indonesian courts predicated solely upon the civil liability provisions of jurisdictions other than Indonesia. As a result, holders of the Notes, as claimants, would be required to pursue claims against us or our commissioners and directors in Indonesian courts on the basis of Indonesian law, which would require re-examination of the underlying claim. There can be no assurance that the claims or remedies available under Indonesian law will be the same, or as extensive, as those available in other jurisdictions.

Indonesia's legal system is a civil law system based on written statutes, and decided legal cases do not constitute binding precedent and are not systematically published. The administration of laws and regulations by courts and government agencies may be subject to considerable discretion. In addition, because relatively few disputes relating to commercial matters and modern financial transactions and instruments are brought before Indonesia's courts, such courts do not necessarily have the experience of courts in other countries. There is uncertainty as to how long it will take for proceedings in Indonesian courts to be concluded and the outcome of proceedings in Indonesian courts may be more uncertain than that of similar proceedings in other jurisdictions. Accordingly, it may not be possible for investors to obtain swift and equitable enforcement of their legal rights.

Holders of the Notes will be exposed to a legal system subject to considerable discretion and uncertainty and may have difficulty pursuing claims under the Notes.

Indonesian legal principles relating to the rights of debtors and creditors, or their practical implementation by Indonesian courts, may differ materially from those that would apply within the jurisdiction of the United States or European Union member states. Neither the rights of debtors nor the rights of creditors under Indonesian law are as clearly established or recognized as under legislation or judicial precedent in the United States and most European Union member states. In addition, under Indonesian law, debtors may have rights and defenses to actions filed by creditors that such debtors would not have in jurisdictions with more established legal regimes such as those in the United States and European Union member states.

Indonesia's legal system is a civil law system based on written statutes in which judicial and administrative decisions do not constitute binding precedent and are not systematically published. Indonesia's commercial and civil laws, as well as rules on judicial process, were historically based on pre-independence Dutch law in effect prior to Indonesia' independence in 1945 and some have not been revised to reflect the complexities of modern financial transactions and instruments. Indonesian courts are often unfamiliar with sophisticated commercial or financial transactions, leading in practice to uncertainty in the interpretation and application of Indonesian legal principles. The application of Indonesian laws depends, in large part, upon subjective criteria such as the good faith of the parties to the transaction and principles of public policy, the practical effect of which is difficult or impossible to predict. Indonesian judges operate in an inquisitorial legal system and have very broad fact-finding powers and a high level of discretion in relation to the manner in which those powers are exercised. In practice, Indonesian court decisions may omit, or may not be decided upon, a legal and factual analysis of the issues presented in a case. As a result, the administration and enforcement of laws and regulations by Indonesian courts and governmental agencies may be subject to considerable discretion and uncertainty. Furthermore, corruption in the court system in Indonesia has been widely reported in publicly available sources.

There is also no assurance that Indonesian courts would enforce, or even consent to adjudicating agreements that are governed by non-Indonesian law. On September 2, 2013, holders of notes issued by BLD Investments Pte. Ltd and guaranteed by PT Bakrieland Development Tbk ("Bakrieland") under a

trust deed governed under English law, filed a suspension of debt payment petition with the Jakarta Commercial Court on grounds that, among other things, Bakrieland had failed to comply with its obligation to repay the outstanding amount of the notes when noteholders exercised their put option under the terms of the notes. In its decision dated September 23, 2013, the Jakarta Commercial Court ruled, among other things, that as the trust deed relating to the notes is governed by English law, all disputes arising out of or in connection with the trust deed must be settled by English courts and the Jakarta Commercial Court did not therefore have authority to examine and adjudicate the case.

As a result, it may be difficult for holders of the Notes to pursue a claim against the Issuer in Indonesia, which may adversely affect or eliminate entirely the holders' ability to obtain and enforce a judgment against the Issuer in Indonesia or increase the holders of the Notes' costs of pursuing, and the time required to pursue, claims against the Issuer.

Indonesia is located in an earthquake and active volcanic zone and is subject to significant geological risk and other natural disasters that could lead to property damage, loss of life, social unrest and economic loss.

The Indonesian archipelago is one of the most seismically active regions in the world. Because it is located in the convergence zone of three major lithospheric plates, it is subject to significant seismic activity that can lead to destructive volcanoes, earthquakes and tsunamis, or tidal waves. For example, in September 2018, a 7.5 magnitude earthquake struck off the central island of Sulawesi and triggered a tsunami that hit the coastal city of Palu. The region is also prone to heavy rains and flooding. The region is also prone to volcanic eruptions, such as recent eruptions of Mount Agung, Mount Merapi and Mount Sinabung. These types of natural disasters have the potential to, among other things, displace local residents and disrupt air travel and local tourism.

While such events have not had a significant economic impact on the Indonesian capital markets in the past, the Government has had to expend significant amounts of resources on emergency aid and resettlement efforts. A significant portion of these costs has been underwritten by foreign governments and international aid agencies. However, there can be no assurance that such aid will continue to be forthcoming, or that it will be delivered to recipients on a timely basis. If the Government is unable to timely deliver foreign aid to affected communities, political and social unrest could result. Additionally, recovery and relief efforts are likely to continue to strain the Government's finances and may affect its ability to meet its obligations on its sovereign debt. Any such failure on the part of the Government, or declaration by it of a moratorium on its sovereign debt, could potentially trigger an event of default under numerous private-sector borrowings including ours, thereby materially and adversely affecting our business, financial condition, results of operations and prospects, and our ability to make payments under the Notes.

In addition, there can be no assurance that future geological or meteorological occurrences or other natural disasters will not significantly impact the Indonesian economy. A significant earthquake or other geological disturbance or other natural disasters in any of Indonesia's more populated cities and financial centers could severely disrupt the Indonesian economy and undermine investor confidence, thereby materially and adversely affecting our business, financial condition, results of operations and prospects, and our ability to make payments under the Notes.

Terrorist attacks, terrorist activities and certain destabilizing events have led to substantial and continuing economic and social volatility in Indonesia, which may materially and adversely affect our business.

The conflicts in the Middle East and past terrorist attacks in North America and Europe have resulted in substantial and continuing economic volatility and social unrest globally and in Southeast

Asia. Further developments stemming from these events or other similar events could cause further volatility. Any additional significant military or other response by affected countries or any further terrorist activities could also materially and adversely affect international financial markets and the Indonesian economy.

In Indonesia during the past several years, there have been various bombing incidents directed toward the Government, foreign governments, and public and commercial buildings frequented by foreigners, including international hotels and the Jakarta Stock Exchange Building. For example, a suicide bombing in Surabaya in May 2018 killed and injured several people. Indonesian and foreign government officials have indicated that these bombings may be linked to international terrorist organizations. In the past, there have also been various terrorist attacks directed towards the Government, foreign governments and public and commercial buildings frequented by foreigners in Indonesia, which killed and injured a number of people.

There can be no assurance that further terrorist acts will not occur in the future. A number of governments have issued warnings to their citizens in relation to a perceived increase in the possibility of terrorist activities in Indonesia, targeting foreign, particularly U.S., interests. Such terrorist acts could destabilize Indonesia and increase internal divisions within the Government as it considers responses to such instability and unrest, thereby adversely affecting investors' confidence in Indonesia and the Indonesian economy. Violent acts arising from and leading to instability and unrest have in the past had, and could continue to have, a material adverse effect on investment and confidence in, and the performance of, the Indonesian economy, and in turn our business. Any of the events described above, including damage to our assets, could cause interruption to parts of our business and materially and adversely affect our financial condition, results of operations and prospects, and our ability to make payments under the Notes.

An actual or perceived outbreak of an infectious disease or any other serious public health concerns in Asia (including Indonesia) and elsewhere may adversely impact our business, results of operations and financial condition.

The outbreak of an infectious disease in Asia (including Indonesia) and elsewhere, together with any resulting restrictions on travel or quarantines imposed, could have a negative impact on the economy and business activity in Indonesia and thereby adversely impact our revenue. Examples are the outbreak in 2003 of Severe Acute Respiratory Syndrome in Asia (SARS), the outbreaks in 2004 and 2005 of Avian influenza, or bird flu, in Asia, the outbreak in 2009 of Influenza A (H1N1), the outbreak in early 2017 of Diphtheria, and the Zika virus.

There can be no assurance that any precautionary measures taken against infectious diseases would be effective. Any intensification or recurrence of past outbreaks or the emergence of other contagious disease or any other serious public health concern in Indonesia may adversely affect our business, financial condition, results of operations and prospects.

Labor activism, unrest and employment legislation may materially and adversely affect us.

In March 2003, the Government enacted Law No. 13/2003 (the "Labor Law") and has further issued implementing regulations allowing employees to form unions without interference from employers. The Labor Law increased, among other things, the amount of severance, service and compensation payments payable to employees upon termination of employment. Based on this law, companies that have 50 employees or more are required to have a bilateral forum consisting of both employers and employees, and a labor union with more than half of a company's employees participating as members may represent the employees to negotiate the collective labor agreements with the employers. The law also established more permissive procedures for staging strikes. Under the

Labor Law, employees have the right to terminate their employment if there is a change of status, change of ownership or merger or consolidation of their employer and receive severance pay, tenure appreciation pay and other compensation which are calculated based on their basic salary and fixed allowances, as well as their length of employment with such employer.

Following its enactment, several labor unions urged the Constitutional Court of the Republic of Indonesia (Mahkamah Konstitusi Republik Indonesia) (the "Indonesian Constitutional Court") to declare certain provisions of the Labor Law unconstitutional and order the Government of Indonesia to revoke those provisions. The Indonesian Constitutional Court declared the Labor Law valid except for certain provisions, including those relating to the right of an employer to terminate the employment of an employee who committed a serious violation and to criminal sanctions against an employee who instigates or participates in an illegal labor strike. As a result, we may not be able to rely on certain provisions of the Labor Law.

The liberalization of regulations permitting the formation of labor unions combined with weak economic conditions has resulted, and will likely continue to result in, labor unrest and activism in Indonesia.

Labor unrest and activism in Indonesia could disrupt our operations, our suppliers or contractors and could affect the financial condition of Indonesian companies in general, depressing the prices of Indonesian securities on the Indonesian or other stock exchanges and the value of the Rupiah relative to other currencies. Such events could materially and adversely affect our business, financial condition, results of operations and prospects, and our ability to make payments under the Notes. In addition, general inflationary pressures or changes in applicable laws and regulations could increase labor costs, which could have a material adverse effect on our business, operational results, financial condition and prospects.

The Labor Law provides that the employer is not allowed to pay an employee wage below the minimum wage stipulated annually by the provincial or regional/city government. The minimum wage is set in accordance with the need for a decent standard of living and taking into consideration the productivity and growth of the economy, however as there are no specific provisions on how to determine the amount of a minimum wage increase, minimum wage increases can be unpredictable. Minimum wage increases can be unpredictable due to local regulations. For example, pursuant to local regulations promulgated in Jakarta, the minimum wage increased from Rp. 3,100,000 per month in 2016 to Rp. 3,355,750 per month in 2017, Rp. 3,648,036 per month in 2018 and Rp. 3,940,973 per month in 2019. Further minimum wage increases in Indonesia could have a material adverse effect on our business, cash flows, financial condition and prospects.

Indonesian accounting standards differ from those in the United States.

We prepare our consolidated financial statements in accordance with IFAS, which differs from U.S. GAAP. As a result, our consolidated financial statements and reported earnings could be significantly different from those that would be reported under U.S. GAAP. This Offering Memorandum does not contain a reconciliation of our consolidated financial statements to U.S. GAAP, and there can be no assurance that such reconciliation would not reveal material differences. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP" for a summary of certain differences that may be applicable to us.

Downgrades of credit ratings of Indonesia and Indonesian companies could materially and adversely affect us and the market price of the Notes.

In 1997, certain internationally recognized statistical rating organizations, including Moody's, Standard & Poor's and Fitch, downgraded Indonesia's sovereign rating, the credit ratings of various

credit instruments of the Government and the credit ratings of a large number of Indonesian banks and other companies. Currently, Indonesia's sovereign foreign currency long-term debt is rated "Baa2 (stable)" by Moody's, "BBB (stable)" by Standard & Poor's and "BBB (stable)" by Fitch. These ratings reflect an assessment of the Government's overall financial capacity to pay its obligations and its ability or willingness to meet its financial commitments as they become due.

No assurance can be given that Moody's, Standard & Poor's, Fitch or any other statistical rating organization will not downgrade the credit ratings of Indonesia or Indonesian companies. Any such downgrade could have an adverse impact on liquidity in the Indonesian financial markets, the ability of the Government and Indonesian companies, including us, to raise additional financing and the interest rates and other commercial terms at which such additional financing is available and could have a material adverse effect on our business, financial condition, results of operations and prospects.

Risks Relating to the Structure of a Particular Issue of Notes

A wide range of Notes may be issued under the Program. A number of these Notes may have features which contain particular risks for potential investors. Set out below is a description of certain such features.

Notes subject to optional redemption.

An optional redemption feature is likely to limit the market value of the Notes. During any period when we may elect to redeem Notes, the market value of those Notes generally will not rise substantially above the price at which they can be redeemed. This also may be true prior to any redemption period.

We may be expected to redeem Notes when our cost of borrowing is lower than the interest rate on the Notes. At those times, an investor generally would not be able to reinvest the redemption proceeds at an effective interest rate as high as the interest rate on the Notes being redeemed and may only be able to do so at a significantly lower rate. Potential investors should consider reinvestment risk in light of other investments available at that time.

Partly-paid Notes.

We may issue Notes where the issue price is payable in more than one installment. Failure to pay any subsequent installment could result in an investor losing all of its investment.

Floating Rate Notes with a multiplier or other leverage factor.

Notes with floating interest rates can be volatile investments. If they are structured to include multipliers or other leverage factors, or caps or floors, or any combination of those features or other similar related features, their market values may be even more volatile than those for securities that do not include those features.

Fixed/Floating Rate Notes.

Fixed/Floating Rate Notes may bear interest at a rate that we may elect to convert from a fixed rate to a floating rate, or from a floating rate to a fixed rate. Our ability to convert the interest rate will affect the secondary market and the market value of such Notes since we may be expected to convert the rate when it is likely to produce a lower overall cost of borrowing. If we convert from a fixed rate

to a floating rate, the spread on the Fixed/Floating Rate Notes may be less favorable than then prevailing spreads on comparable Floating Rate Notes tied to the same reference rate. In addition, the new floating rate at any time may be lower than the rates on other Notes. If we convert from a floating rate to a fixed rate, the fixed rate may be lower than then prevailing rates on our Notes.

Foreign Currency Notes.

Notes denominated in foreign currencies are exposed to the risk of changing foreign exchange rates. Currency values may be affected by complex political and economic factors, including governmental action to fix or support the value of a currency, regardless of other market forces. Noteholders may risk losing their entire investment if exchange rates of the relevant currency do not move in the anticipated direction. This risk is in addition to any performance risk that relates to us or the type of note being issued.

Notes issued at a substantial discount or premium.

The market values of securities issued at a substantial discount or premium to their nominal amount tend to fluctuate more in relation to general changes in interest rates than do prices for conventional interest-bearing securities. Generally, the longer the remaining term of the securities, the greater the price volatility as compared to conventional interest-bearing securities with comparable maturities.

Notes where denominations involve integral multiples.

In the case of Notes which have denominations consisting of a minimum Specified Denomination plus one or more higher integral multiples of another smaller amount, it is possible that Notes may be traded in amounts that are not integral multiples of such minimum Specified Denomination. In such a case, a Noteholder who, as a result of trading such amounts, holds a nominal amount of less than the minimum Specified Denomination will not receive a Definitive Note in respect of such holding (should Definitive Notes be printed) and would need to purchase a nominal amount of Notes such that it holds an amount equal to one or more Specified Denominations.

If Definitive Notes are issued, holders should be aware that Definitive Notes which have a denomination that is not an integral multiple of the minimum Specified Denomination may be illiquid and difficult to trade.

Notes carrying an interest rate linked to "benchmarks" may be exposed to changes to the relevant "benchmark".

The London Interbank Offered Rate ("LIBOR"), the Euro Interbank Offered Rate ("EURIBOR") and other interest rates or other types of rates and indices which are deemed to be "benchmarks" are the subject of ongoing national and international regulatory reform. Following the implementation of any such potential reforms, the manner of administration of benchmarks may change, with the result that they may perform differently than in the past, or benchmarks could be eliminated entirely, or there could be other consequences which cannot be predicted. For example, on July 27, 2017, the United Kingdom Financial Conduct Authority announced that it will no longer persuade or compel banks to submit rates for the calculation of the LIBOR benchmark after 2021 (the "FCA Announcement"). The FCA Announcement indicates that the continuation of LIBOR on the current basis cannot be guaranteed after 2021. On September 21, 2017, the European Central Bank announced that it would be part of a new working group tasked with the identification and adoption of a "risk free overnight rate" which can serve as a basis for an alternative to current benchmarks used in a variety of financial instruments and contracts.

Following the implementation of any such potential reforms, the manner of administration of LIBOR, EURIBOR or other benchmark indices may change, with the result that it may perform differently than in the past, or benchmarks could be eliminated entirely, which could have a material adverse effect on the value of any Floating Rate Notes where the interest rate is calculated with reference to the relevant benchmark indices or may have other consequences that cannot be predicted.

Notes carrying an interest rate which may be converted from fixed to floating interest rates, and vice versa, may have lower market values than other Notes.

Fixed Rate Notes and Floating Rate Notes (as defined in the terms and conditions of the Notes) may bear interest at a rate that the Issuer may elect to convert from a fixed rate to a floating rate, or from a floating rate to a fixed rate. The Issuer's ability to convert the interest rate will affect the secondary market and the market value of such Notes since the Issuer may be expected to convert the rate when it is likely to produce a lower overall cost of borrowing. If the Issuer converts from a fixed rate to a floating rate, the spread on the Fixed Rate Notes may be less favorable than then prevailing spreads on comparable Floating Rate Notes tied to the same reference rate. In addition, the new floating rate may at any time be lower than the rates on other Notes. If the Issuer converts from a floating rate to a fixed rate, the fixed rate may be lower than then prevailing rates on its Notes.

Risks Relating to the Notes

The Notes will be unsecured obligations of the Issuer and will be structurally subordinated to the claims of creditors of the Issuer's subsidiaries.

The claims of all existing and future third-party creditors of the Issuer's subsidiaries as to the cash flows and assets of such companies will have priority over the claims of the shareholders of such subsidiaries, including the Issuer, and the creditors of such shareholders (such as holders of the Notes).

As of December 31, 2018 and March 31, 2019, we had total debt (comprising short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans, and bonds payables) of US$18,245.5 million and US$17,435.8 million, respectively of which US$2,416.6 million and US$2,499.6 million, respectively, was third-party debt of our subsidiaries. The indenture constituting the Notes (the "Indenture") does not contain any restrictions on the ability of the Issuer or its respective subsidiaries to incur additional indebtedness.

The Issuer may not have the ability to raise the funds necessary to finance an offer to repurchase the Notes upon the occurrence of certain events constituting a change of control triggering event or otherwise as required by the Indenture governing the Notes.

Upon the occurrence of certain events constituting a change of control triggering event, the Issuer is required to offer to repurchase all outstanding Notes at a purchase price in cash equal to 101% of their principal amount plus accrued and unpaid interest to the date of purchase. If any such event triggering the Issuer's repurchase obligations were to occur, we cannot assure you that the Issuer would have sufficient funds available at such time to pay the purchase price of the outstanding Notes.

The change of control provision contained in the Indenture may not necessarily afford you protection in the event of certain important corporate events, including a reorganization, restructuring, merger or other similar transaction involving the Issuer that may adversely affect you, because such corporate events may not involve a change in ownership or control or a downgrade of the ratings of the Notes in accordance with the terms of the Indenture, and even if they do, may not constitute a "Change of Control Triggering Event" as defined in the Indenture. Except as described under Condition 5A in "Description of the Notes," the Indenture does not contain provisions that require the Issuer to offer to

repurchase or redeem the Notes in the event of a reorganization, restructuring, merger, recapitalization or similar transaction.

The Notes do not contain restrictive financial or operating covenants.

The Indenture governing the Notes will contain various covenants intended to benefit the interests of the holders of the Notes that limit our ability to, among other things, incur liens under certain circumstances, consolidate or merge with or into, or sell substantially all of our assets to, another person. These covenants are subject to a number of important exceptions and qualifications. For more details, see "Description of the Notes."

The Indenture governing the Notes, however, does not contain restrictive financial or operating covenants or restrictions on the payments of dividends, the incurrence of indebtedness, the issuance or repurchase of securities by us, and the entry into sale and leaseback transactions. In addition, the Indenture does not contain any other covenants or provisions designed to afford holders of the Notes protection in the event of a highly leveraged transaction involving us or in the event of a decline in our credit rating or the rating of the Notes as the result of a takeover, recapitalization, highly leveraged transaction or similar restructuring involving us that could adversely affect such holders. Subject to the terms of our existing corporate debt and other credit facilities, we may incur substantial additional indebtedness in the future.

There has been no prior market for the Notes; the absence of a prior market in the Notes may contribute to a lack of liquidity and the market price of the Notes following this offering may be volatile.

Notes may have no established trading market when issued, and one may never develop. There can be no assurance as to the liquidity of any market that may develop for the Notes, the ability of holders of the Notes to sell their Notes or the prices at which holders of the Notes would be able to sell their Notes. The Notes could trade at prices that may be lower than their initial offering price depending on many factors, including prevailing interest rates, our financial condition and operating results and the market for similar securities. This is particularly the case for Notes that are especially sensitive to interest rate, currency, credit or market risks, and/or are designed for specific investment objectives or strategies or have been structured to meet the investment requirements of limited categories of investors. The Issuer and the Arrangers and Dealers have no obligation to make a market in the Notes. In addition, the market for debt securities in emerging markets has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the Notes. There can be no assurance that the markets for the Notes, if any, will not be subject to similar disruptions. Any disruptions in these markets may have a material adverse effect on the holders of the Notes.

Developments in other markets may adversely affect the market price of the Notes.

The market price of the Notes may be adversely affected by declines in the international financial markets and world economic conditions. The market for securities of Indonesian issuers is, to varying degrees, influenced by economic and market conditions in other markets, especially those in Asia. Although economic conditions are different in each country, investors' reactions to developments in one country can affect the securities markets and the securities of issuers in other countries, including Indonesia. Since the global financial crisis of 2007-2008, international financial markets have experienced significant volatility. If similar developments occur in the international financial markets in the future, the market price of the Notes could be adversely affected.

The ratings assigned to the Program may be lowered or withdrawn entirely in the future.

The Issuer has been assigned an overall credit rating of "Baa2" by Moody's, "BBB" by Standard & Poor's and "BBB" by Fitch. In addition, the Program has also been assigned a rating of

"Baa2" by Moody's, "BBB" by Standard & Poor's and "BBB" by Fitch. These ratings may be lowered or withdrawn entirely in the future. The ratings address the ability to perform obligations under the terms of the Notes and the credit risks in determining the likelihood that payments will be made when due. Additionally, one or more independent credit rating agencies may assign credit ratings to an issue of Notes. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision, suspension or withdrawal at any time. No assurances can be given that a rating will remain for any given period of time or that a rating will not be lowered or withdrawn entirely by the relevant rating agency if in its judgment circumstances in the future so warrant.

Holders of the Notes may be excluded from receiving compensation in respect of a consent, waiver or amendment to the Indenture or the Notes.

We are generally excluded from paying any consideration, directly or indirectly, to any holder of the Notes for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes unless such consideration is offered to be paid or is paid to all holders that consent, waive or agree to amend such term or provision. However, we will be permitted to exclude holders of the Notes in any jurisdiction where such consent, waiver or amendment or payment of consideration for such consent, waiver or amendment, in either case in the manner we deem appropriate, would not be permitted under applicable law in such jurisdiction or would require us to (a) file a registration statement subjecting us or any of our subsidiaries to ongoing periodic reporting or similar requirements, (b) qualify as a foreign corporation or other entity or as a dealer in securities in such jurisdiction if we are not otherwise required to so qualify, (c) generally consent to service of process in any such jurisdiction, or (d) subject us or any of our subsidiaries to taxation in any such jurisdiction if we are not otherwise so subject. We intend to evaluate at the time of any consent, waiver or amendment the costs, potential liabilities and any other factors we consider appropriate at the time associated with extending such consent, waiver or amendment into the relevant jurisdictions. On the basis of this evaluation, we will then make a decision as to how to proceed and whether to extend such consent, waiver or amendment. We cannot assure you that we will include holders of the Notes in jurisdictions where the above exclusions are permitted.

The transfer of Notes is restricted, which may adversely affect their liquidity and the price at which they may be sold.

The Notes have not been registered under, and the Issuer is not obligated to register the Notes under, the Securities Act or the securities laws of any other jurisdiction and, unless so registered, may not be offered or sold except pursuant to an exemption from or a transaction not subject to, the registration requirements of the Securities Act and any other applicable laws. See "Transfer Restrictions." We have not agreed to, or otherwise undertaken, to register the Notes (including by way of an exchange offer), and we have no intention to do so.

An Indonesian court has certain limited rights of a trustee, acting on behalf of holders of certain notes, in a decision that affected the holders' rights and the terms of the notes in connection with a court-supervised debt restructuring.

Indonesian law does not recognize equitable principles in general including, without limitation, the relationship of trustee and beneficiary or other fiduciary relationships as would be the case in common law jurisdictions. In several court-supervised debt restructuring proceedings in Indonesia (*Penundaan Kewajiban Pembayaran Utang* or "PKPU," governed by Law No. 37 of 2004 concerning bankruptcy and PKPU), the PKPU administrator and the Supervisory Judges at the Commercial Court failed to acknowledge the noteholders or the trustee as creditors of the company. In the PKPU proceeding of PT Trikomsel Oke Tbk ("Trikomsel") in early 2016 (the "Trikomsel PKPU"), the PKPU administrators rejected claims in connection with certain foreign currency bonds, concluding that the relevant trustees did not have any standing to make claims on behalf of the relevant noteholders. The

PKPU administrators further held that only individual noteholders that had filed claims on their own would be able to participate in the PKPU proceedings and to vote on the restructuring plan. This stance was further affirmed by the Commercial Court and the Trikomsel PKPU was settled in September 2016, through the ratification of a composition plan (*rencana perdamaian*) which was approved by certain noteholders of Trikomsel, and then ratified by the Jakarta Commercial Court.

In December 2014, the Supervisory Judge in proceedings before the Commercial Court of the Central Jakarta District Court determined that noteholders were not creditors of PT Bakrie Telecom Tbk. ("Bakrie Tel") for purposes of its PKPU proceeding (the "Bakrie Tel PKPU"). Bakrie Tel guaranteed US$380 million of senior notes issued by a Singapore-incorporated special purpose vehicle that is a subsidiary of Bakrie Tel. The proceeds from the offering of the notes were on-lent to Bakrie Tel pursuant to an intercompany loan agreement, which was guaranteed by Bakrie Tel and assigned to the noteholders as collateral. In its decision affirming the composition plan, the Commercial Court accepted the Supervisory Judge's determination that the relevant creditor of BakrieTel in respect of the US$380 million notes was the issuer subsidiary, rather than the noteholders or the trustee, and gave no effect to the guarantee. As such, only the intercompany loan was recognized by the Commercial Court as indebtedness on which Bakrie Tel was liable for purposes of the Bakrie Tel PKPU. As a result, only the issuer subsidiary had standing as a Bakrie Tel creditor to vote in the Bakrie Tel PKPU proceedings, which substantially altered the terms of the U.S. dollar bonds and the guarantee.

It may be difficult or impossible for holders of the Notes or the Trustee to enforce all of their rights under the Notes, including being able to vote in PKPU proceedings in Indonesia. There can also be no assurance that in the future, a PKPU administrator or Commercial Court will not issue a similar decision in PKPU proceedings such as the decision in the Trikomsel PKPU in relation to the capacity of the Trustee or holders of the Notes as our creditors, if we were to contest the enforcement by the Trustee or the holders of the Notes of our obligations under the Notes.

Enforcing the rights of holders of the Notes across multiple jurisdictions may prove to be difficult.

The Notes will be issued by the Company, which is established and existing under the laws of Indonesia. The Notes and the Indenture will be governed by the laws of the State of New York. In the event of a bankruptcy, insolvency, PKPU or similar event, proceedings could be initiated in Indonesia and the United States. Such multi-jurisdictional proceedings are likely to be complex and costly for creditors and may otherwise result in uncertainty and delay regarding the enforcement of the rights of the holders of the Notes. The rights of holders of the Notes under the Notes will be subject to the insolvency and administrative laws of several jurisdictions and there can be no assurance that the holders of the Notes will be able to effectively enforce their rights in such complex multi-jurisdictional bankruptcy, insolvency or similar proceedings. In addition, the bankruptcy, insolvency, administrative, PKPU proceedings and other laws of Indonesia and the United States may be materially different from, or be in conflict with, each other and those with which holders of the Notes may be familiar, including in the areas of the rights of creditors, priority of government entities and other creditors, ability to obtain post-petition interest and duration of the proceeding. The application of these laws, or any conflict among them, could call into question whether any particular jurisdiction's laws should apply and could adversely affect the ability of the holders of the Notes to enforce their rights under the Notes in the relevant jurisdictions or limit any amounts that they may receive.

The Indenture and certain other documents entered into in connection with the Program or any issue of Notes thereunder will also be prepared in Bahasa Indonesia as required under Indonesian law. However, there can be no assurance that, in the event of inconsistencies between the Bahasa Indonesia and English language versions of these documents, an Indonesian court would hold that the English language versions of such documents would prevail.

Pursuant to Law No. 24, agreements between Indonesian entities and other parties must be set out in Bahasa Indonesia, which is the national language of Indonesia, save that where such party is a

foreign entity or individual, the agreement may also be prepared in the language of such foreign party or in the English language. Law No. 24 does not specify any consequences in the event that applicable agreements are not prepared in the Bahasa Indonesia language. On July 7, 2014, the Government issued GR No. 57 to give effect to certain provisions of Law No. 24/2009. GR No. 57 stipulates that one of the functions of Bahasa Indonesia as the state language is to facilitate transactions and commercial documentation. In addition to this implementing regulation, the Minister of State Owned Enterprise has also issued a Circular Letter No. SE-12/MBU/2009 dated November 3, 2009, which recommends that any state-owned enterprise must use Bahasa Indonesia in every memorandum of understanding or agreement to which such state-owned enterprise is a party. While the Indonesian Ministry of Law and Human Rights had issued the Ministry of Law and Human Rights Clarification Letter No. M.HH.UM.01.01-35 TAHUN 2009, dated December 28, 2009, to clarify that the implementation of Law No. 24 is contingent upon the enactment of a Presidential Regulation and until such a Presidential Regulation is enacted, any agreement that is executed prior to the enactment of the Presidential Regulation in English without a Bahasa Indonesia version, is still legal and valid, and shall not violate Law No. 24. This letter was issued only as an opinion and does not fall within the types and hierarchy as stipulated in Article 7 of Law No. 12 of 2014 regarding the Formation of Laws and Regulations, thus the letter cannot be considered as law or regulation. Therefore, the letter has no legal force and we cannot be certain that an Indonesian court would permit the English version to prevail or even consider the English version.

The West Jakarta District Court has however issued a decision in June 2013 which voided a loan agreement on the basis that it was, among other reasons, not executed in Bahasa Indonesia. The decision of the court disagreed with the findings in the Ministry of Law and Human Rights Clarification Letter and concluded that until Law No. 24 is subject to judicial review before the Constitutional Court and amended, the requirement for agreements to which Indonesian entities are a party to be executed in Bahasa Indonesia remains, notwithstanding that a Presidential Regulation has not been enacted. In 2014 and 2015, the case was brought before the High Court of Jakarta and the Supreme Court, both of which affirmed the decision by the West Jakarta Court. The Supreme Court affirmation on the case concludes that every agreement that falls under the provisions of Law No. 24 must be executed in Bahasa Indonesia, although versions in other languages are allowed.

The Indenture and certain other documents entered into in connection with the Program or any issue of Notes thereunder will be prepared in both English and Bahasa Indonesia forms as permitted under Law No. 24 and, pursuant to Law No. 24, each version will be considered equally original. While these documents will expressly state that the English versions will prevail, there can be no assurance that, in light of the ongoing uncertainty surrounding Law No. 24 and the West Jakarta Court decision, that in the event of inconsistencies between the Bahasa Indonesia and English language versions of these documents, an Indonesian court will hold that the English language versions of such documents would prevail, or even consider the English language version.

Some concepts in the English language may not have a corresponding term in Bahasa Indonesia, or may not be fully captured by the Bahasa Indonesia version. If this occurs, there can be no assurance that the Notes, the Indenture and the Program Agreement will be as described in this Offering Memorandum, or will be interpreted and enforced by the Indonesian courts as intended.

USE OF PROCEEDS

We intend to use net proceeds from the issue of each Tranche of Notes to finance capital expenditures and for general corporate purposes or as set forth in the Pricing Supplement applicable to such Notes.

EXCHANGE CONTROLS

Exchange Controls

Indonesia has limited foreign exchange controls. Law No. 24 of 1999, dated May 17, 1999, on the Flow of the Foreign Exchange System and Exchange Rate System provides that a person may hold and use foreign currency freely in the Republic of Indonesia. However, to maintain the stability of the Rupiah, and to prevent the utilization of the Rupiah for speculative purposes by non-residents, Bank Indonesia has introduced regulations to restrict the movement of Rupiah from banks within Indonesia to offshore banks, an offshore branch of an Indonesian bank, or any investment denominated in Rupiah with foreign parties and/or Indonesian parties domiciled or permanently residing outside Indonesia, thereby limiting offshore trading to existing sources of liquidity. In addition, Bank Indonesia has the authority to request information and data concerning the foreign exchange activities of all persons and legal entities that are domiciled, or who plan to be domiciled in Indonesia for at least one year. Bank Indonesia regulations also require companies that have total assets or total annual gross revenues of at least Rp. 100 billion, to report to Bank Indonesia all data concerning their foreign currency activities. If requested by Bank Indonesia, we must also provide Bank Indonesia with information and documents relating to the reporting of foreign exchange activities.

Purchasing of Foreign Currencies against Rupiah through Banks

Foreign Exchange Transaction Against Rupiah between Banks and Domestic Parties

Bank Indonesia introduced Bank Indonesia Regulation No. 18/18/PBI/2016 dated September 7, 2016 on Foreign Exchange Transaction Against Rupiah between Banks and Domestic Parties, as implemented by Board of Governance Member Regulation No. 20/16/PADG/2018 dated August 15, 2018 on Foreign Exchange and Transactions Against Rupiah between Banks and Domestic Parties ("Regulation 18/18"). Under Regulation 18/18, any conversion of Rupiah into foreign currency for spot and standard derivative (plain vanilla) transactions that exceed certain thresholds described below must be based on an underlying transaction and supported by underlying transaction documents. The thresholds are as follows: (i) the purchase of foreign currency through a spot transaction in an amount exceeding US$25,000 (or its equivalent) per month per customer, (ii) the purchase of foreign currency through a derivative transaction in an amount exceeding US$100,000 per month (or its equivalent) per customer, (iii) the sale of foreign currencies against Rupiah through forward or option transactions in an amount exceeding US$5,000,000 and US$1,000,000 (or its equivalent) per transaction per customer, respectively, or (iv) for the purchase of foreign currency in the form of a call spread option in any amount, there must be an underlying transaction. Further, the maximum amount of a foreign exchange conversion cannot exceed the value of the underlying transaction.

Under Regulation 18/18, an "underlying transaction" can be: (i) the trade of goods and services (including income and expense estimation), (ii) an investment in the form of direct investment, portfolio investment, loans, capital, and other investments, both domestic and overseas, and/or (iii) a grant of a facility or credit from a bank in foreign currency and/or in Rupiah for trading and investment activities. The following are each not an "underlying transaction: (i) the placement of funds in commercial banks in Indonesia (among others, savings, demand deposits, time deposits, and negotiable certificates deposit), (ii) money transfers by a funds transfer/remittance company, (iii) undrawn credit facilities (including standby loans and undisbursed loans), and (iv) the use of the negotiable instrument of Bank Indonesia in foreign currencies.

Any Indonesian customer entering into: (i) a foreign exchange spot transaction against Rupiah in an amount exceeding US$25,000 or its equivalent per month per customer for a spot transaction or US$100,000 or its equivalent per month per customer for a standard derivative (plain vanilla)

transaction, or (ii) a call spread option against Rupiah in any amount, will be required to submit supporting documents to the transacting bank. These documents include a duly stamped or authenticated written statement confirming that: (i) the underlying transaction document is valid and correct, (ii) the amount of foreign currency purchased is or will not exceed the amount stated in the underlying transaction document, and (iii) in case the underlying transaction document is only an estimation, the total needs, purpose of utilization, and date of foreign currencies utilization. For the purchase of foreign currencies not exceeding such thresholds, the Indonesian parties must declare in a duly stamped letter or authenticated written statement that its aggregate foreign currency purchases do not exceed each threshold (as applicable) per month in the Indonesian banking system.

Foreign Exchange Transaction Against Rupiah between Banks and Foreign Parties

Bank Indonesia Regulation No. 18/19/PBI/2016 dated September 7, 2016 on Foreign Exchange Transaction Against Rupiah between Banks and Foreign Parties, as implemented by Board of Governance Member Regulation No. 20/17/PADG/2018 dated August 15, 2018 on Foreign Exchange Transaction Against Rupiah Transactions between Banks and Foreign Parties ("Regulation 18/19") adopts thresholds and documentation requirements for foreign exchange transactions between banks and foreign parties that are similar to the thresholds and requirements of Regulation 18/18 described in "*— Foreign Exchange Transaction Against Rupiah between Banks and Domestic Parties*" above. Under Regulation 18/19, any conversion of Rupiah into foreign currency for spot and standard derivative (plain vanilla) transactions that exceed certain thresholds described below must be based on an underlying transaction and supported by underlying transaction documents. An "underlying transaction" under Regulation 18/19 may be: (i) a domestic and international trade of goods and services; and/or (ii) an investment in the form of direct investment, portfolio investment, loans, capital and other investment, both domestic and overseas.

Any foreign party entering into: (i) a foreign exchange spot transaction against Rupiah in an amount exceeding US$25,000 (or its equivalent) per month per foreign party for a spot transaction and US$100,000 (or its equivalent) per transaction per foreign party or outstanding per bank for a standard derivative (plain vanilla) transaction, or (ii) a call spread option against the Rupiah in any amount, will be required to submit certain supporting documents to the transacting bank. These documents include a duly stamped or authenticated written statement confirming that: (a) the underlying transaction document is valid and correct, (b) the amount of foreign currency purchased is or will not exceed the amount stated in the underlying transaction document, (c) in case the underlying transaction document is only an estimation of the purchase of foreign currencies against Rupiah, the total needs, purpose of utilization, and date of foreign currencies utilization, and (d) in case the underlying transaction document is only an estimation of the sale of foreign currencies against Rupiah, the source of funds, amount, and availability date of the foreign currencies, in the event that the underlying transaction document is only an estimation. For the purchase of foreign currencies not exceeding such thresholds, the foreign parties must declare in a duly stamped letter or authenticated written statement that its aggregate foreign currency purchases do not exceed each threshold (as applicable) per month per foreign party in the Indonesian banking system. Such written statement may be in the form of e-mail, SWIFT message, negative confirmation or business internet banking.

As a state-owned company, we are also subject to Bank Indonesia requirements which restrict our ability to source U.S. dollars only from three Indonesian state-owned enterprise banks: PT Bank Mandiri (Persero) Tbk, PT Bank Negara Indonesia (Persero) Tbk and PT Bank Rakyat Indonesia (Persero) Tbk.

CAPITALIZATION

The following table sets forth our consolidated capitalization as of March 31, 2019. This table should be read in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our unaudited interim consolidated financial statements as of March 31, 2019 and 2018 and for the periods then ended and the related notes thereto included elsewhere in this Offering Memorandum. There have been no material changes to our capitalization since March 31, 2019.

	As of March 31, 2019 (unaudited) (US$ in millions)
Indebtedness	
Short-term loans	3,671.4
Long-term liabilities — bank loans — net (including current portion)	1,931.9
Due to the Government — two-step loans	732.7
Bonds payables[1]	11,099.8
Total debt	17,435.8
Equity	
Share capital	
Authorized — 600,000,000 ordinary shares at par value of Rp. 1,000,000 (full amount) per share Issued and paid-up — 171,227,044 shares	16,191.2
Additional paid-in capital	(924.3)
Government contributed assets pending final clarification of status	401.1
Other equity components	208.6
Retained earnings	
— Appropriated	8,796.4
— Unappropriated	3,045.9
Total equity attributable to owners of the parent entity	27,718.9
Non-controlling interests	2,403.0
Total equity	30,121.9
Total capitalization[2]	**47,557.7**

Notes:

(1) Includes the following (all bonds issued by the Issuer unless otherwise noted): (i) US$1,000.0 million 2021 Notes and US$500.0 million 6.5% senior notes due 2041, both of which were issued in May 2011, (ii) US$1,250.0 million 2022 Notes (of which US$1,242.0 million 2022 Notes remains outstanding) and US$1,250.0 million 6.0% senior notes due 2042, both of which were issued in May 2012, (iii) US$1,625.0 million 4.3% senior notes due 2023 and US$1,625.0 million 5.625% senior notes due 2043, both of which were issued under the Program in May 2013, (iv) US$1,500.0 million 6.45% senior notes due 2044 issued under the Program in 2014, (v) US$1,350.0 million 5.125% senior notes due 2024, issued in 2014 by PGN, (vi) US$625 million 4.450% senior notes due 2024 issued in 2017 by PT Saka Energi Indonesia and (vii) US$750.0 million 6.5% senior notes due 2048, which were issued under the Program in October 2018. This amount is presented net of discount and issuance cost.

(2) Represents total debt plus total equity.

SELECTED CONSOLIDATED FINANCIAL AND OTHER DATA

The selected audited consolidated financial information as of and for the years ended December 31, 2018, 2017 and 2016 have been derived from our audited consolidated financial statements which are included elsewhere in this Offering Memorandum. The selected unaudited interim consolidated financial information as of and for the three-month periods ended March 31, 2019 and 2018 have been derived from our unaudited interim consolidated financial statements included elsewhere in this Offering Memorandum. These financial statements have been prepared on the same basis as our audited consolidated financial statements. Our results for any interim period may not be indicative of our results for the full year or for any other period.

You should read the following selected consolidated financial information in conjunction with our consolidated financial statements and related notes, "Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements," "Presentation of Financial and Other Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Offering Memorandum. Our consolidated financial statements have been prepared and presented in accordance with IFAS, which differs in certain respects from U.S. GAAP. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP."

Consolidated Statement of Profit or Loss and Other Comprehensive Income Data

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Sales and other operating revenues					
Domestic sales of crude oil, natural gas, geothermal energy and oil products	35,841.7	39,788.8	44,742.5	10,714.0	10,318.0
Subsidy reimbursements from the government	2,568.8	3,572.1	5,632.5	1,342.8	1,212.5
Export of crude oil, natural gas and oil products	968.4	1,874.3	3,637.0	747.9	867.3
Marketing fees	(257.5)	25.5	15.4	1.8	2.9
Revenues from other operating activities	690.5	740.1	3,906.2	325.4	269.5
Total sales and other operating revenues	**39,811.9**	**46,000.7**	**57,933.6**	**13,131.9**	**12,670.2**
Costs of sales and other direct costs					
Cost of goods sold	(26,181.0)	(33,175.7)	(42,787.9)	(9,632.0)	(9,013.1)
Upstream production and lifting costs	(3,270.0)	(3,421.2)	(4,386.5)	(1,224.1)	(1,160.9)
Exploration costs	(109.2)	(165.4)	(267.7)	(63.8)	(25.8)
Expenses from other operating activities	(703.5)	(863.0)	(1,272.0)	(300.1)	(377.4)
Total cost of sales and other direct costs	**(30,263.7)**	**(37,625.2)**	**(48,714.1)**	**(11,220.0)**	**(10,577.2)**
Gross profit	**9,548.3**	**8,375.5**	**9,219.5**	**1,911.9**	**2,093.0**
Selling and marketing expenses	(1,339.6)	(1,590.2)	(1,642.8)	(294.2)	(446.0)
General and administrative expenses	(1,509.3)	(1,598.9)	(1,329.9)	(281.2)	(394.8)
Gain (loss) on foreign exchange — net	(57.5)	58.1	19.6	(67.5)	119.9
Finance income	336.6	233.1	256.6	48.0	145.9
Finance costs	(770.5)	(817.7)	(835.2)	(204.4)	(241.5)
Share in net profit of associates and joint venture	18.7	37.9	122.7	124.9	15.8
Other expenses — net	(877.9)	(830.6)	(80.8)	179.9	(98.7)
	(4,199.4)	(4,508.3)	(3,489.9)	(494.5)	(899.3)
Profit before income tax	**5,348.9**	**3,867.2**	**5,729.6**	**1,417.4**	**1,193.6**
Income tax expense — net	(1,877.6)	(1,166.8)	(3,013.2)	(729.6)	(620.3)
Profit for the period/year after the effect of merging entity's income adjustment	**3,471.2**	**2,700.4**	**2,716.4**	**687.8**	**573.4**
Other Comprehensive (Loss) Income					
Items not to be reclassified to profit or loss in subsequent periods (net of tax)					
Remeasurement of net defined benefit liability	(73.4)	(129.1)	228.5	75.5	(28.7)
Foreign exchange difference from translation of financial statements in foreign currency	14.7	7.1	(79.6)	5.4	36.4
Share of other comprehensive income of associates	1.5	(25.1)	(130.8)	(21.3)	(69.2)
Other comprehensive income (loss), net of tax	**(57.2)**	**(147.1)**	**18.2**	**59.7**	**(61.5)**
Total comprehensive income for the period/ year after the effect of merging entity's income adjustment	**3,414.0**	**2,553.3**	**2,734.6**	**747.5**	**511.9**
Adjustment of merging entity's income:					
Owners of the parent entity	(173.3)	(81.5)	(45.8)	(45.8)	—
Non-controlling interests	(135.2)	(66.2)	(34.6)	(34.6)	—
	(308.6)	**(147.8)**	**(80.4)**	**(80.4)**	**—**

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Profit for the period/year before the effect of merging entity's income adjustment attributable to:					
Owners of the parent entity	3,147.0	2,540.2	2,526.8	534.6	519.1
Non-controlling interests	15.6	12.4	109.3	72.8	54.2
	3,162.7	**2,552.6**	**2,636.0**	**607.4**	**573.4**
Adjustment of merging entity's comprehensive income:					
Owners of the parent entity	(177.0)	(80.7)	(42.5)	(42.5)	—
Non-controlling interests	(138.3)	(65.5)	(32.7)	(32.7)	—
	(315.2)	**(146.3)**	**(75.2)**	**(75.2)**	**—**
Total comprehensive income for the period/ year before effect of merging entity's comprehensive income (loss) adjustment attributable to:					
Owners of the parent entity	3,081.5	2,363.3	2,536.6	608.2	120.2
Non-controlling interests	17.2	43.7	122.8	64.0	391.7
	3,098.8	**2,407.0**	**2,659.3**	**672.2**	**511.9**

Consolidated Statement of Financial Position Data

	As of December 31,			As of March 31,
	2016	2017	2018	2019
				(Unaudited)
		(US$ in millions)		
Assets				
Current assets				
Cash and cash equivalents	6,721.6	6,409.8	9,112.3	8,322.1
Restricted cash	122.7	119.7	108.9	109.3
Short-term investments	130.8	249.3	225.2	298.4
Trade receivables				
Related parties	1,422.3	1,095.0	1,297.7	1,537.3
Third parties	1,442.5	1,580.6	1,933.5	2,187.0
Due from the Government — current portion	1,792.5	1,492.6	1,834.3	2,537.7
Other receivables				
Related parties	242.8	255.1	149.2	165.2
Third parties	649.8	620.5	734.3	780.0
Inventories	4,795.0	6,036.1	6,323.2	6,530.2
Prepaid taxes — current portion	567.6	794.3	820.6	499.7
Prepayments and advances	503.4	476.3	535.0	703.1
Other investments	43.2	27.3	80.2	85.1
Total current assets	**18,434.1**	**19,156.6**	**23,154.2**	**23,755.1**
Non-current assets				
Due from the Government — net of current portion	—	663.1	2,924.1	3,029.2
Deferred tax assets	751.5	1,371.1	1,441.9	1,428.8
Long-term investments	3,329.4	2,970.9	2,819.1	2,728.6
Fixed assets	12,156.8	12,439.5	12,859.3	12,640.8
Oil & gas and geothermal properties	16,397.7	18,031.4	18,614.3	18,541.8
Prepaid taxes — net of current portion	1,469.8	829.3	820.3	874.4
Other non-current assets	1,436.9	1,977.5	2,085.3	2,086.5
Total non-current assets	**35,542.0**	**38,282.8**	**41,564.2**	**41,330.1**
Total assets	**53,976.1**	**57,439.4**	**64,718.5**	**65,085.2**
Liabilities and equity				
Short-term liabilities				
Short-term loans	230.3	452.9	4,347.0	3,671.4
Trade payables				
Related parties	118.5	49.3	78.8	53.6
Third parties	3,290.7	3,900.1	3,597.8	3,236.5
Due to the Government — current portion	952.5	1,050.6	1,207.7	1,725.7
Taxes payable				
Income taxes	475.6	308.8	467.6	521.4
Other taxes	251.6	250.5	258.4	299.8
Accrued expenses	1,596.6	2,019.9	2,135.5	2,345.5
Long-term liabilities — current portion	722.2	366.0	420.6	423.3
Other payables				
Related parties	50.9	56.6	54.0	38.8
Third parties	1,026.8	1,121.5	1,203.4	1,429.8
Deferred revenue — current portion	177.5	260.8	202.0	169.8
Total short-term liabilities	**8,893.2**	**9,837.0**	**13,972.9**	**13,915.6**

	As of December 31,			As of March 31,
	2016	2017	2018	2019
				(Unaudited)
		(US$ in millions)		
Long-term liabilities				
Due to the Government — net of current portion	732.6	780.6	795.1	790.4
Deferred tax liabilities	2,528.5	2,848.2	3,307.4	3,354.9
Long-term liabilities — net of current portion	2,716.9	2,109.8	1,805.3	1,651.9
Bonds payables	9,772.7	10,385.9	11,094.1	11,099.8
Employee benefit liabilities	2,058.7	2,208.2	1,850.4	1,905.2
Provision for decommissioning and site restoration	1,900.1	2,129.3	2,029.7	2,050.2
Deferred revenue — net of current portion	65.7	42.7	74.6	77.3
Other non-current payables	62.9	84.4	178.9	118.1
Total long-term liabilities	**19,838.1**	**20,589.1**	**21,135.5**	**21,047.7**
Total liabilities	**28,731.3**	**30,426.1**	**35,108.4**	**34,963.3**
Equity				
Equity attributable to owners of the parent entity				
Share capital				
Authorized — 600,000,000 (2019 and 2018) and 200,000,000 (2017 and 2016) ordinary shares at par value of Rp. 1,000,000 (full amount) per share,				
Issued and paid up — 171,227,044 shares (2019 and 2018) and 133,090,697 shares (2017 and 2016)	13,417.0	13,417.0	16,191.2	16,191.2
Additional paid-in capital	2.7	2.7	(924.3)	(924.3)
Merging entity's equity	1,801.7	1,804.6	—	—
Government contributed assets pending final clarification of status	1.4	1.4	401.1	401.1
Other equity components	664.6	487.7	607.6	208.6
Retained earnings				
Appropriated	4,631.4	6,871.1	8,796.4	8,796.4
Unappropriated	3,147.0	2,540.2	2,526.8	3,045.9
Total Equity Attributable to Owners of the Parent Entity	**23,666.0**	**25,124.7**	**27,598.7**	**27,718.9**
Non-controlling interest	1,578.8	1,888.5	2,011.3	2,403.0
Total equity	**25,244.8**	**27,013.3**	**29,610.0**	**30,121.9**
Total liabilities and equity	**53,976.1**	**57,439.4**	**64,718.5**	**65,085.2**

Consolidated Statement of Cash Flows Data

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Cash flows from operating activities:					
Cash receipts from customers	42,723.5	40,220.3	48,878.5	12,316.1	11,953.5
Cash receipts from the Government	3,722.3	3,787.9	7,805.7	1,136.9	974.0
Cash receipts from tax restitution	39.5	616.7	185.0	1.9	3.1
Payments to suppliers	(29,211.9)	(29,261.8)	(38,227.6)	(10,055.0)	(8,877.8)
Payments to the Government	(5,173.5)	(7,524.6)	(11,279.6)	(2,337.4)	(2,250.1)
Payments of corporate income taxes	(2,009.0)	(2,100.3)	(2,688.2)	(567.5)	(642.8)
Cash paid to employees and management	(1,321.4)	(1,540.8)	(1,640.9)	(487.4)	(445.2)
Receipts from (placement of) restricted cash	(494.0)	(156.0)	73.1	(18.8)	0
Receipts of interest	115.7	35.6	63.3	20.5	43.8
Net cash generated from operating activities	**8,391.2**	**4,076.9**	**3,169.4**	**9.4**	**758.5**
Cash flows from investing activities:					
Proceeds from disposal of short-term investment	45.8	99.9	198.4	25.1	24.6
Proceeds from disposal of long-term investments	4.6	15.8	—	—	—
Interest received from investments	4.0	18.2	13.8	5.8	1.9
Cash receipts from other investing activities	—	28.7	262.2	84.7	2.1
Proceeds from sale of fixed assets	2.2	0.1	0.2	0.2	0.2
Dividends received from associates	233.6	81.6	214.1	2.3	0
Purchases of fixed assets	(1,012.7)	(981.9)	(1,288.0)	(163.5)	(196.0)
Purchases of oil and gas and geothermal properties	(1,365.1)	(892.0)	(1,482.5)	(257.7)	(421.6)
Placements in long-term investments	(336.5)	(660.0)	(1,062.2)	(22.7)	(26.7)
Placements in short-term investments	(142.8)	(226.3)	(237.6)	(35.4)	(17.2)
Payments for exploration and evaluation assets	(18.4)	(37.2)	(99.5)	(7.8)	(4.6)
Placement of restricted cash	(10.3)	(29.4)	(22.6)	0	0
Addition of participating interest	(23.8)	—	—	—	—
Cash obtained due to change of control	—	203.2	—	—	—
Net cash used in investing activities	**(2,619.4)**	**(2,379.3)**	**(3,503.8)**	**(369.1)**	**(637.4)**
Cash flows from financing activities:					
Proceeds from short-term loans	2,377.3	4,039.5	9,489.2	830.3	1,079.3
Proceeds from bond issuance	—	—	734.4	—	—
Proceeds from long-term loans	1,674.4	1,288.2	255.9	44.4	51.3
Repayments of short-term loans	(4,057.9)	(3,786.7)	(5,583.3)	(830.3)	(1,885.7)
Repayments of long-term loans	(2,248.4)	(2,109.0)	(465.4)	(201.8)	(182.2)
Dividend payments	(554.9)	(867.8)	(585.8)	—	—
Payments of finance costs	(530.8)	(523.1)	(538.5)	(15.9)	(18.1)
Repayments of bonds payables	(139.8)	—	(37.6)	—	—
Receipts from (placement of) restricted cash	0.4	(13.2)	(0.3)	0.1	(0.7)
Net cash generated from (used in) financing activities	**(3,479.6)**	**(1,972.2)**	**3,268.7**	**(173.0)**	**(956.2)**
Net increase (decrease) in cash and cash equivalents	**2,292.3**	**(274.6)**	**2,934.3**	**(532.7)**	**(835.1)**
Effect of exchange rate changes on cash and cash equivalents	20.7	(37.2)	(231.8)	(44.7)	44.9
Cash and cash equivalents at beginning of the year	**4,408.7**	**6,721.6**	**6,409.8**	**6,409.8**	**9,112.3**
Cash and cash equivalents at end of the year	**6,721.6**	**6,409.8**	**9,112.3**	**5,832.5**	**8,322.1**

Segment Results

The following table presents segment revenues and results for our upstream and downstream segments for the periods indicated. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in this Offering Memorandum. Our segment results are derived from our total segment revenues, after deducting total costs of sales and other direct costs, selling and marketing expenses and general and administrative expenses relating to such segments. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview of Segment Results."

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Total upstream segment revenues	6,272.3	7,966.3	12,552.6	2,795.0	3,022.9
Upstream segment results	2,065.7	3,327.9	5,960.6	1,272.9	1,368.7
Total downstream segment revenues	32,477.7	37,372.7	46,091.3	10,005.7	10,223.2
Downstream segment results	4,176.2	1,282.2	(286.8)	(28.0)	(160.4)

Non-GAAP and Other Financial Data

	As of or for the Years Ended December 31,			As of or for the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions, except ratios and percentages)	(Unaudited)	
Capital expenditure[1]	3,025.0	5,423.2	4,533.5	303.7	668.8
Interest expense[2]	531.3	564.1	581.0	134.8	169.8
Adjusted EBITDA[3]	8,162.4	7,108.0	9,204.4	2,244.0	2,047.3
Total debt[4]	13,895.5	13,824.2	18,245.5	13,657.8	17,435.8
Total debt/Adjusted EBITDA (times)	1.7	1.9	2.0	6.1[6]	8.5[6]
Adjusted EBITDA/Total sales and other operating revenues (%)	20.5	15.5	15.9	17.1	16.2
Total debt to Total equity (%)	55.0	51.2	61.6	49.2	57.9
Adjusted EBITDA/Interest expense (times)	15.4	12.6	15.8	16.6	12.1
Dividend payout ratio (%)[5]	39.1	27.6	23.1	—	—

Notes:

(1) Capital expenditure is comprised of additions to fixed assets, oil and gas and geothermal properties and long term investments — investments in oil and gas blocks-net. For details of our capital expenditure, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of capital expenditure for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Additions of fixed assets	1,200.7	1,587.6	1,493.2	280.5	174.3
Additions of oil and gas, and geothermal properties	1,812.0	3,835.6	3,040.3	23.2	494.5
Additions of long term investments — investments in oil and gas blocks-net	12.3	—	—	—	—
Capital expenditure	3,025.0	5,423.2	4,533.5	303.7	668.8

(2) Interest expense is comprised of finance costs for short-term loans, long-term loans and bonds. For details of our loans and bonds, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness." The following table reconciles our net income under IFAS to our definition of interest expense for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Finance Costs:					
Short-term loans	13.9	8.5	56.5	2.9	32.6
Long-term loans	183.2	203.0	172.6	46.6	28.4
Bonds	334.2	352.6	351.9	85.3	108.8
Interest expense	531.3	564.1	581.0	134.8	169.8

(3) We calculate Adjusted EBITDA by adding depreciation, depletion and amortization, finance costs and income tax expense — net to profit for the period/year before the effect of merging entity's income adjustment and subtracting finance income, in accordance with BUMN Regulation KEPMEN 100. BUMN Regulation KEPMEN 100 requires adjustment for all finance costs and does not take into account the effects of merging entity's income adjustment, which arise in connection with acquisitions during the year or period. In comparison, our calculations of EBITDA in the past adjusted for interest expense and not accretion expenses related to decommissioning and site restoration or other finance costs and took into account the effects of merging entity's income adjustment. Adjusted EBITDA and the related ratios presented in this Offering Memorandum are therefore not comparable to our previously disclosed EBITDA and related ratios.

Adjusted EBITDA is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP. Adjusted EBITDA is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with IFAS or U.S. GAAP or an alternative to cash flows from operating activities as a measure of liquidity. In addition, Adjusted EBITDA is not a standardized term, hence a direct comparison between companies using such term may not be possible. We have included Adjusted EBITDA because we believe it is an indicative measure of our operating performance and is used by investors and analysts to evaluate companies in our industry. The following table reconciles our net income under IFAS to our definition of Adjusted EBITDA for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Profit for the period/year before the effect of merging entity's income adjustment	3,162.7	2,552.6	2,636.0	607.4	573.4
Adjustments:					
Finance income	(336.6)	(233.1)	(256.6)	(48.0)	(145.9)
Finance costs	770.5	817.7	835.2	204.4	241.5
Income tax expense — net	1,877.6	1,166.8	3,013.2	729.6	620.3
Depreciation, depletion and amortization expense	2,688.2	2,804.0	2,976.6	750.6	758.0
Adjusted EBITDA	8,162.4	7,108.0	9,204.4	2,244.0	2,047.3

(4) Total debt is comprised of short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans and bonds payables. "Two-step loans" is comprised of: (i) the Ulubelu and Lahendong geothermal project loan, (ii) the Lumut Balai geothermal project loan, (iii) the Ngurah Rai Airport refueling facility construction project loan, (iv) the South Sumatera West Java gas transmission pipeline development project loan, and (v) the Domestic Gas market development project loan. For details, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Indebtedness."

(5) Dividend payout ratios are calculated as dividends paid during the year equivalents in U.S. dollars divided by the previous year's profit for the year before the effect of merging entity's income adjustment. Dividend payout ratio is a supplemental measure of our performance and liquidity that is not required by or presented in accordance with IFAS or U.S. GAAP. Dividend payout ratio is not a measurement of financial performance or liquidity under IFAS or U.S. GAAP and should not be considered as an alternative to net income, operating income, or any other performance measure derived in accordance with IFAS or U.S. GAAP or an alternative to cash flow from operating activities as a measure of liquidity. In addition,

dividend payout ratio is not a standardized term, hence a direct comparisons between companies using such a term may not be possible. For details of our dividend payout ratios, see "Risk Factors — Risk relating to our Company — We are subject to the control of the Government and there is no guarantee that they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue." The following table reconciles our net income under IFAS to our definition of dividend payout ratios for the periods indicated:

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
				(Unaudited)	
	(US$ in millions except percentages)				
Dividend paid during the year/period equivalents in U.S. dollars	554.9	867.8	585.8	—	—
Prior year profit for the period/year before merging entity's income adjustment attributable to owners of the parent entity	1,420.2	3,147.0	2,540.2	—	—
Dividend payout ratio (%)	39.1	27.6	23.1	—	—

(6) Total debt/Adjusted EBITDA ratios for the three-month periods ended March 31, 2018 and 2019 are calculated based on total debt as of such dates and Adjusted EBITDA for the three-month periods then ended. Therefore, they are not comparable to, and are higher than, our total debt/ Adjusted EBITDA ratios for the years ended December 31, 2016, 2017 and 2018, which are calculated using Adjusted EBITDA for the twelve-month periods then ended.

Selected Reserve, Production and Operating Data

Except where attributed to Wood Mackenzie, all information in this Offering Memorandum relating to oil and gas reserves is presented on the basis of our "net reserves" which represents our share of the gross reserves in a block, field or specified area, attributable to our working interest before deducting the share payable to the Government as owner of the reserves, pursuant to the terms of the relevant production sharing arrangement or cooperation contract and the cost recovery and any applicable taxes. In this Offering Memorandum, except where attributed to Wood Mackenzie, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007, and estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves. For more information, see "Presentation of Financial and Other Information — Oil and Gas Reserves."

The information on our oil and gas production presented and referred to as "production" in this Offering Memorandum is our "net production" and represents our share of the oil and/or gas production from a block, field or specified area, attributable to our working interest before deducting the share payable to the Government pursuant to the terms of the relevant production sharing arrangement or cooperation contract and the cost recovery and any applicable taxes. See "Risk Factors — Risks Relating to Our Upstream Operations — Our crude oil, natural gas and geothermal reserve estimates are uncertain and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these reserves" and "Business — Pertamina Upstream Business — Reserves."

The following table sets forth the present value and estimated volume of our total net oil and gas proved and proved plus probable reserves.

	Crude Oil (mmbbls)	Natural Gas (bcf)	Combined (mmboe)
2019 (as of March 31, 2019)[1]			
Total net proved plus probable reserves (as of March 31, 2019)	**1,329.0**	**7,898.0**	**2,692.2**
Probable reserves	289.2	1,602.7	565.8
Total net proved reserves (as of March 31, 2019)	**1,039.8**	**6,295.3**	**2,126.3**
2018[1]			
Total net proved plus probable reserves (as of December 31, 2018)	**1,362.8**	**7,825.4**	**2,713.4**
Probable reserves	290.7	1,628.0	571.7
Total net proved reserves (as of December 31, 2018)	**1,072.0**	**6,197.4**	**2,141.7**
2017[1]			
Total net proved plus probable reserves (as of December 31, 2017)	**1,606.3**	**8,574.0**	**3,084.6**
Probable reserves	356.6	1,655.0	641.6
Total net proved reserves (as of December 31, 2017)	**1,249.7**	**6,919.0**	**2,443.0**
2016[1]			
Total net proved plus probable reserves (as of December 31, 2016)	**1,719.1**	**9,452.0**	**3,350.6**
Probable reserves	275.0	1,101.5	465.1
Total net proved reserves (as of December 31, 2016)	**1,444.2**	**8,350.5**	**2,885.4**

Note:

(1) Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. Estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. Estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

The following table sets forth our average daily oil and gas production and average realized sales prices for the periods indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Average daily oil and gas production:					
Crude oil (mbbls/d)	311.6	341.7	393.4	385.9	416.8
Natural gas (mmcf/d)	1,960.9	2,035.4	3,058.9	3,114.6	2,910.8
Total (mboe/d)	**650.0**	**693.0**	**921.4**	944.5	919.2
Average realized sales prices:					
Crude oil (US$ per bbl)	39.8	51.2	70.6	63.7	63.1
Natural gas (US$ per mcf)	6.0	5.8	6.3	4.4	4.8

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with our consolidated financial statements and the related notes, "Presentation of Financial and Other Data," "Summary Consolidated Financial and Other Data" and "Selected Consolidated Financial and Other Data" included elsewhere in this Offering Memorandum. Our consolidated financial statements have been prepared and presented in accordance with IFAS, which differs in certain respects from U.S. GAAP. See "Summary of Certain Significant Differences Between IFAS and U.S. GAAP." Unless otherwise indicated, references in this section to years are to our fiscal year ended December 31 in such year.

Overview

We are a fully integrated national oil, gas and geothermal company, wholly owned by the Government and headquartered in Jakarta, Indonesia. We have an operating history of more than 60 years. We were established on December 10, 1957 and became an Indonesian limited liability company in 2003.

We are engaged in a broad spectrum of upstream and downstream oil, gas, geothermal, petrochemical and other energy operations. Our lines of business are organized into upstream and downstream sectors in accordance with Indonesian oil, gas and geothermal regulations. We are also mandated by the Government to distribute subsidized fuel, LPG and CNG in Indonesia and to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program and to encourage the use of CNG as an alternative fuel.

In April 2018, the Issuer acquired the Government's 56.96% interest shares in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. In December 2018, the Issuer transferred 51.0% of its stake in PT Pertamina Gas to PGN, which reduced the Issuer's effective total ownership in PT Pertamina Gas from 100.0% to 78.05%. The transfer of Pertagas to PGN is intended to grow our gas business by creating an extensive and far-reaching distribution and transmission pipeline network in Indonesia and unlocking benefits of scale.

We derive our sales and other operating revenues primarily from sales of refined petroleum products, sales of crude oil and natural gas, sales of processed gas products, sales of steam and electricity and sales of petrochemical products.

Factors Affecting Our Business and Results of Operations

The main factors affecting our business and results of operations are described below.

PSO Mandate

In 2016, 2017 and 2018 and in the three months ended March 31, 2019, 32.0%, 27.5%, 26.5% and 30.3%, respectively, of our sales and other operating revenues (excluding marketing fees) were derived from the distribution of our various fuel products pursuant to our PSO mandate from the Government. Under our PSO mandate, we distribute certain grades of oil products to the public at regulated prices. We receive subsidy reimbursements from the Government for the distribution of certain of these products under our PSO mandate, in particular automotive diesel oil, kerosene, and LPG in 3kg cylinders, in accordance with a pre-set formula which is revised from time to time by the Government.

We participate in an annual tender process for the PSO mandate and have been granted a PSO mandate in each of the last three years. Based on the total amount of subsidized fuel distributed in

Indonesia (based on publicly available Government data), we had 98.2% of the PSO market in each of 2016, 2017 and 2018. We believe this is due to our extensive distribution network. If the number of oil and gas companies which are granted the PSO mandate increases or the other holders of the PSO mandate expand their distribution networks, our share of the PSO market would be reduced, which would in turn affect our revenue from the distribution of subsidized fuel.

Historically, the Government's regulated prices of subsidized fuel products have not been sufficient to meet our costs of producing or importing and distributing for certain fuel products, and we rely on subsidy reimbursements from the Government to address the shortfall between the regulated retail prices and our costs of producing or importing and distributing such fuel. The subsidy reimbursement amount for automotive diesel oil is subject to a fixed amount set by the Government. The subsidy reimbursement formula determined by the Government for kerosene distributed under the PSO mandate is based on MOPS's three-month average price for jet kerosene (which is the Oil Fuel Market Index Price for kerosene) less the regulated retail price. Based on Decree of the Minister of Energy and Mineral Resources No. 61K/12/MEM/2019, the subsidy reimbursement formula for LPG in 3kg cylinders is based on the benchmark price for LPG in 3kg cylinders, which is determined by the market index price for LPG in 3kg cylinders (as stipulated by the Government) applicable in the relevant month, plus distribution (including handling) costs and margins less the regulated retail price. The Government sets these subsidy reimbursement amounts and formulas in conjunction with the setting of the State Budget.

In setting these subsidy reimbursement formulas, the Government assumes that the price of crude oil will not exceed a certain threshold. In 2016, 2017 and 2018, the Government assumed with respect to the margin component of the subsidy reimbursement formulas for kerosene and LPG that the cost of crude oil would not be greater than US$40.20, US$51.20 and US$70, respectively, per barrel. In 2019, the Government has assumed with respect to the margin component of the subsidy reimbursement formulas for kerosene and LPG that the cost of crude oil will not be greater than US$70 per barrel. Under these subsidy reimbursement formulas, fluctuations in the cost of purchasing crude oil and LPG are intended to be matched by the fluctuations in MOPS or the market index price (as stipulated by the Government) and the margin is intended to compensate us for distribution, transportation and other costs and to provide for the opportunity to realize profits from the remainder. If crude oil prices exceed the ceiling price assumed by the Government or our transportation, distribution or other costs increase, we may not be able to recover the full costs of distributing subsidized fuel and LPG under the compensation formula and may incur losses as a result.

Because the margin component of the compensation formula and regulated retail prices of subsidized fuel products are fixed by the Government, whenever crude oil exceeds the ceiling price assumed by the Government (as it has in the past, most recently in 2018) or our transportation, distribution or other costs increase, we may not be able to recover the full costs of producing and distributing subsidized fuel and LPG under the subsidy reimbursement formula and may incur losses as a result. In particular, the costs of fuel required in our refining activities fluctuate with the costs of crude oil and increases in the costs of crude oil cause our costs of refining subsidized fuel to increase. We may not be able to recover such increased costs due to the fixed margin of these subsidy reimbursement formulas. In addition, the fixed subsidy reimbursement amounts for automotive diesel oil typically does not cover the full costs of producing and distributing automotive diesel oil, which are partially or fully offset by the sales of our other products.

The Government pays subsidy reimbursements to us on a monthly basis. In determining the subsidy reimbursement payable to us in any given month for the distribution of kerosene, the Government's policy is to use MOPS from the month immediately prior to the month which the subsidy reimbursement claim relates to. This lag in the value of MOPS used in the subsidy reimbursement formula may result in the compensation we receive under our PSO mandate for kerosene being insufficient to cover the cost of our raw materials in months where there is a significant increase in crude oil prices from the previous month.

In 2016, 2017, 2018 and 2019, we have received or expect to receive (as applicable) compensation from the Government under our PSO mandate as set forth in the table below.

	Compensation for Production and Distribution of Oil Products	Compensation for Production and Distribution of LPG
2016	Rp. 1,000.0 per liter from January 1, 2016 to June 30, 2016 and Rp. 500.0 per liter from June 1, 2016 to December 31, 2016 for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$68.64/mt + 1.88% CP Aramco + Rp. 1,750.0/kg less the regulated retail price from January 1, 2016 to July 31, 2016, and CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price from August 1, 2016 to December 31, 2016
2017	Rp. 500.0 per liter for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price
2018	Rp. 2,000.0 per liter for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price
2019	Rp. 2,000.0 per liter for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	103.85% market index price of LPG in 3kg cylinders (as stipulated by the Government) + US$50.11/mt + Rp. 1,879.0/kg

The amount of subsidy reimbursements that we receive from the Government typically increases in line with increases in the price of crude oil and natural gas globally and in Indonesia because, historically during periods of rising crude prices, the Government has chosen to increase our subsidy reimbursement amounts in 2017 instead of increasing regulated fuel prices in the country. In 2016, 2017, 2018 and in the three months ended March 31, 2019, domestic sales of crude oil, natural gas, geothermal energy and oil products represented 90.0%, 86.5%, 77.2% and 81.4%, respectively, of our total sales and other operating revenues while cost subsidy reimbursements under our PSO mandate represented 6.5%, 7.8%, 9.7% and 9.6%, respectively, of our total sales and other operating revenues.

From 2016 to 2017, as a percentage of our total sales and other operating revenues, our domestic sales revenue decreased, while our cost subsidy reimbursements increased primarily due to an increase in subsidy reimbursements received for sales of LPG in 3kg cylinders. From 2017 to 2018, as a percentage of our total sales and other operating revenues, our domestic sales revenue decreased, cost subsidy reimbursements increased and, on a combined basis, domestic sales and cost subsidy reimbursements decreased as a percentage of our total sales and other operating revenue due to increased revenues from crude exports and other operating activities, including additional amounts received from the Government for the difference between the formula price and the government price of crude oil. In the three-month period ended March 31, 2019, as a percentage of our total sales and other operating revenues, our domestic sales revenue increased, cost subsidy reimbursements decreased and, on a combined basis, domestic sales and cost subsidy reimbursements increased as a percentage of our total sales and other operating revenue due to a decrease in revenues from other operating activities, as a result of us not yet receiving amounts from the Government for the difference between the formula price and the government price of crude oil in that period.

Although crude oil prices rose in 2017 and regulated retail sales prices under the PSO mandate continued to be insufficient to cover our costs of producing and distributing those PSO fuel products in that year, the subsidy reimbursements that we received in 2017 for the distribution of LPG in 3kg cylinders under the compensation formula reduced the shortfall between the retail sales prices and our production and distribution costs for those products and offset the losses that we incurred for the distribution of other oil products under the PSO mandate. In contrast, in 2018, subsidy reimbursements that we received from the Government for the distribution of PSO fuel products were insufficient to cover our costs of production and distribution of those products and, pursuant to Presidential Regulation No. 43 of 2018, which amends Presidential Regulation No. 191 of 2014, concerning the Provision, Distribution and Retail Price of Oil Fuels ("PR 43/2018"), we received additional amounts from the Government to compensate us for the difference between the formula price and the government price of crude oil.

In the near term, we expect our costs of production and distribution to increase due to rising oil prices globally. To date, the Government has not adjusted the regulated prices of crude oil or our price-regulated products to take into account these rising costs. If oil prices continue to increase and Government-regulated pricing formulae remain unchanged, and if no further action is taken by the Government to address any shortfalls, we would expect our profit margins on such products to decline.

See also "Business — Pertamina Downstream Business — PSO" and "Risk Factors — Risks Relating to Our Downstream Operations — We compete with other oil and gas companies in connection with our downstream activities and for the PSO mandate," "Risk Factors — Risks Relating to Our Downstream Operations — A substantial part of our revenues is derived from the provision of subsidized fuel products" and "Risk Factors — Risks Relating to Our Downstream Operations — We may not be able to pass on increases in costs of our raw materials for products distributed under our PSO or other mandates from the Government or where the prices of such products are fixed at the request of the Government" for more information relating to our PSO mandate.

Price of Crude Oil, Natural Gas and Refined Products

Our operating results are impacted by the international market prices for crude oil and refined products. The volatility of the market prices of crude oil, natural gas and refined products is subject to a variety of factors beyond our control, including international events and circumstances, political developments and instability in petroleum producing regions such as the Middle East, Latin America and Western Africa. Higher prices for crude oil and natural gas generally have a positive effect on our operating profit in our upstream business, as our exploration and production business benefits from the increase in prices of the oil and gas we produce and deliver. Lower crude oil and natural gas prices generally have a corresponding negative effect in our upstream business. In our downstream segment, changes in the price of crude oil also affect the world market prices for certain petrochemical feedstocks. As a result, our costs for producing petrochemical products typically track crude oil prices. The effect of changes in crude oil and natural gas prices on our refined petroleum products business depends on the rate and extent to which the prices of such products adjust to reflect those changes.

Our policy is to use as much of the crude oil which we produce as we can as feedstock in our refineries and to purchase crude oil on the open market to meet any shortfall between our crude oil production (either in the quality or quantity of the crude oil) and the demands of our refineries. A portion of the crude oil we produce is not of suitable quality for our refineries. We generally either trade such crude oil in exchange for crude oil of suitable quality or sell such crude oil either on the term or spot market. In 2016, 2017 and 2018 and the three months ended March 31, 2019, 85.8%, 80.8%, 80.5% and 78.2%, respectively, of the crude oil we produced was used as feedstock in our refineries (a portion of which was our DMO), while the balance of our crude oil production in such years was either traded or sold to third parties. See "Business — Pertamina Upstream Business — Sales and Distribution — Crude Oil" for more information on our crude oil sales.

The crude oil we supply to our refineries and trade is sold at the prevailing market price of crude oil so increases in crude oil prices would increase revenues in our upstream segment. We purchase more crude oil than we trade or sell to third parties so increases in the price of crude oil cause our costs of producing refined products to increase. For example, we commonly purchase Azeri crude oil from Azerbaijan and Bonny Light crude oil, Qua Iboe crude oil and Escravos crude oil from Nigeria for our refineries as they are well suited for blending with the crude oil we produce before refining. These purchases are made at spot market rates through producers (including national oil companies), equity holders (including multinational oil companies) and trading companies, so increases in the costs of Azeri crude oil, Bonny Light crude oil, Qua Iboe crude oil and Escravos crude oil on the spot market tend to cause our costs of production to increase.

Because demand for refined products in Indonesia exceeds the total production output of Indonesian refineries, we also import refined products to meet local demand. Fluctuations in the price of crude oil also affect market prices for certain petroleum products. Increases in the price of the refined products which we import would increase our purchasing costs. Such increases in our costs of producing and importing refined products may have a negative impact on our profits if the prices at which such products can be distributed do not fluctuate to the same extent because such prices are regulated due to market forces or otherwise.

Crude Oil, Natural Gas and Refined Product Production Volumes

Our sales and other operating revenues are positively correlated with our crude oil and natural gas production volumes, which in turn depend primarily on the level of the proven and developed reserves in the fields in which we have an interest. The level of proven and developed reserves is affected by such factors as:

- the extent to which we acquire interests in producing reserves or acquire other companies that own producing reserves;
- the rate at which exploration leads to successful discoveries and the speed at which successful exploration and development move to production;
- the speed at which we and our partners deplete the reserves through production of crude oil and natural gas; and
- the expiration and extension of the terms of the production sharing arrangements under which we and our partners produce crude oil and natural gas.

As our policy is to use as much of the crude oil which we produce as we can as feedstock in our refineries, our level of crude oil production directly affects the amount of refined products we can produce for sale or need to purchase in open markets. Other factors that affect our refining levels are the availability of suitable feedstock for purchase in the open markets and our refining capacity.

In addition, our refined products production levels are directly affected by the total production capacity of our six refineries, which has remained constant at 1,031.0 mbbls/d for each of the past three years and as of March 31, 2019. Our average utilization rate for our refineries was 77.4% in 2016, 79.0% in 2017 and 83.1% in 2018, respectively. Our total production capacity is affected by the facilities in place at our refineries, and our average processing capacity utilization rate is affected by the efficiency of our facilities and may also be affected by periods of scheduled and unscheduled downtime and the availability of suitable feedstock.

Our results of operations are also affected by the mix of refined products that we produce and sell. Certain non-subsidized refined products, such as our petrochemical products, provide us with higher margins than other products, such as subsidized fuels distributed under our PSO mandate. For example, in the last three years, our sales of assignment motor gasoline have decreased while our sales of non-subsidized higher grade gasoline have increased. This shift has primarily been driven by regulatory restrictions on assignment motor gasoline sales (see "—Government Ownership and Regulation") and strong demand for our non-subsidized higher grade product. Key factors contributing to our product mix in a given period will include the types of refined products that are in our product portfolio, the types of refined products that are subject to Government subsidies, customer demand, and our ability to produce such fuels. Our product portfolio and our ability to produce certain products is dependent on the NCI of our refining facilities.

The Terms of Our PSCs

Our PSCs contain customary cost recovery provisions which permit us to recover approved costs incurred in capital investment for exploration and development, and production and operating expenses against available revenues generated by the PSC after deduction of first tranche petroleum ("FTP"). Under FTP terms, the Government and the contractor are entitled to take and receive oil and gas of a certain percentage each year of the total production in a particular production area, depending on contract terms, before any deduction for cost recovery. After FTP and recovery of all approved costs, the Government is entitled to a specified profit share of the remaining production and we keep the rest as our profit share.

Because our recoverable costs are customarily settled in gas and oil, the exact amount realizable by us out of these cost recoveries varies depending on the market prices of gas and oil. For example, if oil prices decrease, our cost recovery portion of production will rise and our net entitlement under our PSCs will therefore also rise in terms of the number of barrels of oil. However, despite such increase in our net entitlement, a decline in oil prices may lead to a decline in revenues from the sales of the oil that we receive from our net entitlement. The international market for gas and oil is volatile, and has recently been characterized by significant price fluctuations. See "Risk Factors — Risks relating to our Company — The volatility in the prices of crude oil, natural gas and our refined products and the uncertainty of the market dynamics for oil and gas could adversely affect our business, financial condition, results of operations and prospects."

Our share of our PSCs' pre-tax profits, as set forth in our various PSCs, ranged from 30% to 86% for oil and 40% to 87% for gas, depending on the production sharing arrangement and without taking into account the impact of cost recovery and DMO. DMO are established by SKK MIGAS on a contract-by-contract basis. Under PEP's and PEPC's PSC relating to all of our wholly owned oil and gas fields, our share of profits before tax for oil and gas is 67.2%, which is higher than other PSCs in Indonesia. After a period of five years commencing from the month of the first delivery of crude oil produced from each new field in a given contract area, the contractor will typically be subject to DMO to sell approximately 7.5% to 16.8% of the crude oil produced from the contract area at a subsidized price, ranging from 15% to 25% of the market price, depending on the PSC. The size of our DMO and the discount to market price at which we must fulfill them would have a direct effect on revenues from our upstream business. In each of 2016, 2017 and 2018, our DMO accounted for 25% of our net crude oil production.

The feedstock that we purchase from our upstream operations for our refineries includes our DMO. Under the PSCs to which PEP or PEPC are party, we are not required to sell crude oil under our DMO at a subsidized price and we receive market price for the crude oil delivered under our DMO. The majority of the crude oil which we supply under our DMO is provided by PEP and PEPC. In addition, in accordance with the Oil and Gas Law of 2001, our production sharing arrangements include a DMO provision with respect to gas production. The size of our DMO with respect to our gas

production and the terms, including the price at which we are required to supply the gas, has a direct effect on revenues from our upstream business.

We expect our allocation of FTP and net entitlement to increase in line with an anticipated decline in Indonesia's production of crude oil due to current production being mature and the expectation that no new major discoveries will be made in the current decade. We expect to import more crude oil and feedstock for our refineries in future years as a result of this decline in our FTP allocation and net entitlement which will cause our costs of sales to increase.

Indonesian income tax rates (including dividend tax) on our PSCs currently vary depending on the contract terms for the applicable PSC where revenue is generated, and this percentage changes our effective tax rate. The average income tax rates (including dividend tax) applicable to our PSCs ranges from 25% to 48%. Our income tax expense is significantly influenced by the fact that PSCs cannot be consolidated for Indonesian income tax purposes, as this prevents us from off-setting losses from one PSC from profits from another PSC. Each PSC is taxed individually and no cross deduction is allowed.

See "Indonesian Regulatory Framework — Oil and Gas Regulation — Upstream — PSCs" for further information.

Movements in the Exchange Rate Between the Rupiah and U.S. Dollar

Although the U.S. dollar is our functional and reporting currency, as approximately 80% of our revenues were directly or indirectly denominated in U.S. dollars in 2016, 2017 and 2018 and the three months ended March 31, 2019, respectively, fluctuations in the exchange rate between the Rupiah and the U.S. dollar would still affect our results of operations. A depreciation of the Rupiah against the U.S. dollar has a negative effect on revenues and receivables paid in Rupiah. Our payments within Indonesia are made in Rupiah due to compliance with applicable laws in Indonesia requiring payments to be denominated in Rupiah, while most of our operating costs, particularly in relation to the procurement of crude oil and oil products, are incurred and paid in U.S. dollars. However, as prices of our refined products and our gas sales agreements are based on U.S. dollars converted to Rupiah, an appreciation of the Rupiah against the U.S. dollar may also have a negative effect on our business as it may reduce our prices in Rupiah terms.

Trade Receivables

As of December 31, 2018, we had trade receivables of US$3.231.1 million, 40.2% of which was owed to us by our related parties. Out of this amount, US$381.6 million was owed to us by PLN and its subsidiaries, our related party and a Government-owned electricity company, and US$318.1 million was owed to us by the Indonesian Armed Forces and the Ministry of Defense. As of March 31, 2019, we had trade receivables of US$3,724.2 million, 41.3% of which was owed to us by our related parties. Out of this amount, US$433.8 million was owed to us by the Indonesian Armed Forces and the Ministry of Defense, US$386.0 million was owed to us by PT Garuda Indonesia (Persero) Tbk and US$366.9 million was owed to us by PLN and its subsidiaries, our related party and a Government-owned electricity company.

As of March 31, 2019, the top ten parties from which trade receivables were due were the Indonesian Armed Forces and Ministry of Defense, PT Garuda Indonesia (Persero) Tbk, PLN and its subsidiaries, PT Patra SK, PT Pupuk Indonesia (Persero), Polisi Republik Indonesia, PT Merpati Nusantara Airlines (Persero), PT Aneka Tambang, PT Pembangkit Jawa-Bali and PPT Energy Trading Co., Ltd.

Our outstanding trade receivables are not covered by credit insurance (although certain of our trade receivables from unrelated third parties are covered by collateral and/or bank guarantees). We have procedures such as credit scoring, collateral requirement and regular confirmation and reconciliation, to monitor and limit exposure to credit risk on our outstanding trade receivables. We make provisions for impairment of trade receivables from related and third parties on an individual basis. Based on management's review of the collectible balances of trade receivables as of December 31, 2016, 2017 and 2018 and March 31, 2019, our management believes that the provision for impairment made with respect to each such period is adequate to cover potential losses as a result of uncollected trade receivables. We have also implemented a credit management system that monitors customer usage of credit limits and automatically blocks credit lines beginning on the seventh day of nonpayment after a maturity date, and we impose penalties on overdue payments on a case-by-case basis.

As of December 31, 2016, 2017 and 2018 and March 31, 2019, we had made provisions for impairment in respect of trade receivables from third parties of US$204.3 million, US$211.5 million, US$228.0 million and US$212.1 million, respectively, and provisions for impairment in respect of trade receivables from related parties of US$105.8 million, US$46.8 million, US$32.7 million and US$33.2 million, respectively. The higher provisions for impairment in respect of trade receivables from related parties in 2016 primarily related to receivables from the Indonesian Armed Forces and Ministry of Defense that were more than one year past due.

Government Ownership and Regulation

The Government is our sole shareholder and, through its agencies, it is likely to continue to retain control over us. We derive certain benefits from being a Government-owned entity, including a favorable allocation of net entitlement under certain of our PSCs, access to two-step loans, which are loans disbursed through a lending mechanism managed by the Government which have favorable terms and are only available to Government-owned entities and a right to request to renew cooperation contracts on our existing oil and gas blocks in Indonesia.

The Government could affect us through other actions, such as the alterations to the PSO mandate and the compensation we receive under it, the retail price which it sets for assignment fuel products, renegotiation or nullification of existing concessions and contracts, the imposition of taxes and foreign exchange restrictions or requiring that we supply fuel to our related parties at a discounted rate. Furthermore, because the majority of our accounts receivable are from Government-owned entities and the Government is our sole shareholder, we may have limited courses of action against it.

The oil, gas and geothermal industry in Indonesia is highly regulated and in the past the oil, gas and geothermal regulatory regimes have been subject to frequent change. We are subject to similar industry risks as other oil, gas and geothermal companies operating in Indonesia with respect to changes in governmental regulation, which may positively or adversely affect our business, financial condition, results of operations and prospects. For example, in May 2018, the Government enacted PR 43/2018, which limits the sale of assignment motor gasoline in Java province. This change, together with the recent growth in sales of non-subsidized higher grade gasoline, has led in a decrease in our assignment motor gasoline sales from US$11,488.5 million in 2016 to US$5,429.3 million in 2017 and US$4,509.2 million in 2018. For more information, see "Risk Factors — Risks Relating to the Oil, Gas and Geothermal Industry."

As our sole shareholder, the Government has the power to control the amount and timing of dividends payable by us to them as our sole shareholder. We have historically been required to pay dividends to the Government as an estimated amount based on a specified percentage of our distributable profit as shown in our unaudited financial statements in advance of our audited financial

statements becoming available. As of December 31, 2016, 2017 and 2018, we declared dividends of Rp. 6.8 trillion (US$499.4 million), Rp. 12.1 trillion (US$907.4 million) and Rp. 8.6 trillion (US$614.9 million), respectively, to the Government.

See "Risk Factors — Risks Relating to our Company — We are subject to the control of the Government and there is no guarantee they will always act in our best interests. We also derive certain benefits from being a state-owned entity, and we cannot guarantee that any or all of these benefits will continue," "Risk Factors — Risks Relating to our Company — We are exposed to credit risk on our trade receivables," and "Risk Factors — Risks Relating to Our Downstream Operations — We may not be able to pass on increases in costs of our raw materials for products distributed under our PSO or other mandates from the Government or where the prices of such products are fixed at the request of the Government."

Growth Strategy

We have in the past pursued and plan to continue to pursue strategic acquisitions, joint ventures and investments, in particular with respect to assets that are in production or advanced stages of development, that will expand our oil, gas and geothermal business, in Indonesia and internationally and develop our gas infrastructure in Sumatra and Java. We also aim to maintain our existing leadership in our downstream businesses by growing and optimizing our refining capabilities, expanding our retail fuel station network and solidifying our market leadership in fuel, gas and petrochemical products distribution in Indonesia. In the long term, we aim to supplement our existing core businesses and become one of Asia's leading integrated energy companies by becoming the largest petrochemical distributor in Indonesia, one of the largest power producers in Indonesia, and a producer of biofuels and LNG in addition to our current role as an operator of LNG plants on behalf of the Government. In line with these expansion goals, we anticipate that we will also need to increase our storage capacity, invest in our transmission and distribution infrastructure and network.

The implementation of our growth strategy may increase our debt financing requirements, lead to increased levels of debt and debt servicing costs and significant capital expenditures in the future. See also "Risk Factors — Risks Relating to Our Company — We may be unable to accomplish our development plans for our projects on schedule or within our budgeted costs and we are unable to give any assurance that these plans, if completed, will achieve our development aims."

Acquisition of PGN, Transfer of Pertagas and Restatement of Consolidated Financial Statements

In April 2018, the Issuer acquired the Government's 56.96% interest in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. PGN is a public company that is listed on the Indonesia Stock Exchange, under the ticker symbol "PGAS," and certain additional information regarding PGN, including its annual reports and financial statements, are publicly available. The Issuer is the largest shareholder of PGN. For more information about PGN, see "Business — PGN Operations."

At the time, the Issuer and PGN held 60.0% and 40.0% respectively, of PT Nusantara Regas ("Regas"), which develops and operates LNG storage facilities and regasification terminals. As a result of the Issuer's acquisition of PGN, the Issuer has 82.78% effective ownership of Regas and control over its activities. Accordingly, the Issuer has consolidated Regas in its consolidated financial statements since the acquisition of PGN completed.

In December 2018, PGN acquired from the Issuer a 51.0% stake in PT Pertamina Gas. Through the acquisition of PT Pertamina Gas, PGN also acquired PT Pertamina Gas' subsidiaries PT Pertagas

Niaga, PT Perta Arun Gas, PT Perta Daya Gas and PT Perta Samtan. The Issuer retains a 49.0% direct stake in PT Pertamina Gas. While the Issuer's effective total ownership in PT Pertamina Gas (i.e. including its indirect stake via its ownership of PGN) is reduced from 100.0% to 78.05%, the transfer of Pertagas to PGN is intended to grow our gas business by creating an extensive and far-reaching distribution and transmission pipeline network in Indonesia and unlocking benefits of scale.

For more information about PGN, see "Business — Pertamina Gas Business — Gas Transmission and Distribution Through PGN."

Accounting of PGN and Pertagas; Restatement of Our Consolidated Financial Statements

Prior to our acquisition of PGN, our Company and PGN were under the common control of the Government, which owned 100% of our issued share capital and 56.96% interest in PGN.

Under SFAS 38, a business combination transaction that entails the transfer or reorganization of businesses under the same business group is not a change of ownership in economic substance. The pooling-of-interests method of accounting is applied, and the acquisition does not result in a gain or loss for the group as a whole or to the individual entity within the same group. The Government's transfer of its interests in PGN to the Issuer did not constitute a change of ownership in economic substance, nor did it result in a gain or loss for the Government as a whole or to our Company or PGN. Our acquisition of PGN was considered a common control business combination and was accounted for using the pooling-of-interests method in accordance with SFAS 38.

In applying the pooling-of-interests method, the components of our financial statements for the period during which the business combination occurred and for other periods presented for comparison purposes are presented in such a manner as if the combination has already occurred since the beginning of the period in which the entities were under common control. As a consequence of the application of SFAS 38, following completion in 2018 of the Issuer's acquisition of PGN, subsequent consolidation of Regas and transfer of Pertagas to PGN, components of our consolidated statement of financial position as of December 31, 2016 and 2017 and components of our consolidated statements of comprehensive profit or loss and other comprehensive income for the year ended December 31, 2017 were restated in June 2018. The excess of the cost of the business combination and the carrying amount of the acquired business was US$927.0 million, which was included in our consolidated statement of financial position as of December 31, 2017 as additional paid-in capital.

For more information, see Notes 4(a) and 4(b) to the consolidated financial statements, which are included elsewhere in this Offering Memorandum.

Internal Controls Over Financial Reporting

We are committed to establishing and improving policies and practices in order to implement a system of good internal controls and corporate governance. Accordingly, in connection with the annual audits of our consolidated financial statements as of and for the years ended December 31, 2018, 2017 and 2016, we requested that KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited) provide us, from their assessment of our internal controls to determine the nature, extent and timing of audit procedures for the purpose of expressing an opinion on the consolidated financial statements, with management letters identifying, among other matters, aspects of our internal controls relevant to financial reporting that require remediation or improvement, their implications to our consolidated financial statements, and recommendations for remediation or improvement.

The letters issued by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited) in 2017, 2018 and 2019 (collectively, the "Management Letters") identified a number of aspects of our internal controls and operations relevant to financial reporting which the independent auditors observed and for which the independent auditors recommended remediation or improvement.

Following our receipt of each of the Management Letters, we took measures to remedy the deficiencies and to ensure the completeness, timeliness and accuracy of our consolidated financial statements. Among other things, we have:

- improved systems for recording of fiscal assets;
- replaced or repaired oil tank measuring devices which are known to be unreliable;
- reviewed and corrected income tax and value-added tax reconciliations;
- adopted the most recent recommended IT protocols, configurations and controls;
- performed periodic physical checks of certain land assets;
- corrected the calculation and presentation of employee loan balance;
- centralized our human resources function;
- established criteria for obsolete and slow moving inventory; and
- monitoring over the completion of assets under construction.

In addition, we are in the process of implementing the following measures to address additional recommendations related to oil tank measuring devices, inventory monitoring systems and IT systems.

We also requested and received from our independent auditors similar management letters identifying, among other matters, aspects of our internal controls relevant to financial reporting that require remediation or improvement, their implications to our consolidated financial statements, and recommendations for remediation or improvement in connection with the annual audits of our consolidated financial statements as of and for the years ended December 31, 2012, 2013 and 2014 and have taken measures to remedy the deficiencies identified and adopt the recommendations set forth therein.

As of the date of this Offering Memorandum, we believe that we have or are in the process of addressing the majority of the issues identified in the Management Letters. Our independent auditors expressed an unqualified opinion on our audited consolidated financial statements for the years ended December 31, 2018, 2017 and 2016. See also "Risk Factors — Risks Relating to Our Company — If we fail to establish or maintain an effective system of internal controls, we may be unable to accurately report our financial results or prevent fraud."

Critical Accounting Policies

Our critical accounting policies and practices are those that we believe are the most important to the presentation of our financial condition and results of operations and that require subjective judgment on behalf of management. In many cases, the accounting treatment of a particular transaction is specifically dictated by generally accepted accounting principles. We believe the policies and practices described below are our critical accounting policies and practices. For a summary of all our accounting policies, including the policies discussed below, see Notes 2 and 3 to the consolidated financial statements as of and for the years ended December 31, 2018, 2017 and 2016, which are included elsewhere in this Offering Memorandum.

In the application of our accounting policies, we are required to make estimates, judgments and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. These estimates and assumptions are based on historical experience and other factors we consider relevant.

Judgments made by our management in the process of applying our accounting policies that have the most significant effects on amounts in our consolidated financial statements relate to (i) exploration and evaluation expenditure, (ii) development expenditure, and (iii) uncertain tax exposure. For more information on judgments related to exploration and evaluation expenditure, see "— Oil and Gas Properties." Development activities commence after a project is sanctioned by the appropriate level of management, and our judgement is required in determining when a project is economically viable.

We base our assumptions and estimates on parameters that are available when our consolidated financial statements were prepared. Existing circumstances and assumptions about future developments may change due to changes in the market and conditions arising beyond our control. Areas in which we rely on the use of assumptions and estimates relate to (i) impairment of non-financial assets; (ii) reserve estimates; (iii) oil and gas, and geothermal properties; (iv) provision for the impairment of loans and receivables; (v) amounts due from the Government; (vi) depreciation, estimate of residual values and useful lives of fixed assets; (vii) deferred tax assets; and (viii) provision for decommissioning and site restoration.

Impairment of Non-Financial Assets

In accordance with our accounting policy, each asset or cash generating unit ("CGU") is evaluated every reporting period to determine whether there are any indications of impairment.

The determination of fair value and value in use requires management to make estimates and assumptions about expected production and sales volumes, commodity prices (considering current and historical prices, price trends and related factors), reserves, operating costs, decommissioning and site restoration cost, and future capital expenditure. These estimates and assumptions are subject to risk and uncertainty. There is a possibility that changes in circumstances may alter these projections, which may have an impact on the recoverable amount of the assets.

Reserve Estimates

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves include:

- proved developed reserves: amounts of hydrocarbons that are expected to be retrieved through existing wells, facilities and operating methods; and

- proved undeveloped reserves: amounts of hydrocarbons that are expected to be retrieved following new drilling, facilities and operating methods.

The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables such as the quality of available geological, technical and economic data, results of drilling, testing and production after the date of the estimates, the production performance of the reservoirs, production techniques, projecting future rates of production, the anticipated cost and timing of development expenditures, the availability for commercial market, anticipated commodity prices and exchange rates.

As the economic assumptions used to estimate reserves change from year to year, and additional geological data are generated during the course of operations, estimates of reserves may change from year to year. Changes in reported reserves may affect our financial results and financial position in a number of ways, including:

- Depreciation and amortization, which are determined on a unit of production basis, or where the useful economic lives of assets change.

- Decommissioning, site restoration and environmental provision may change where changes in estimated reserves affect expectations about the timing or cost of these activities.

- The carrying value of deferred tax assets/liabilities may change due to changes in estimates of the likely recovery of the tax benefits.

We estimate proven reserves on the basis of our oil and gas resource management system, which contains procedures for classifying and estimating reserves. Until December 31, 2018, the procedures for our oil and gas resource management system and the classifications of our reserves were consistent with PRMS 2007. PRMS 2007 was generally considered the oil and gas industry standard for reserve reporting until it was superseded by PRMS 2018 in 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. With respect to our reserves managed by PEP, prior to 2017 we had used the SPE 2001 guidelines (which were replaced by PRMS 2007) to determine the procedures for our oil and gas resource management system and the classifications of PEP's reserves. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. The characteristics of the estimation uncertainty of natural reservoirs of oil and gas reserve may lead to changes in the estimated reserves due to the additional data obtained by us.

Oil and Gas, and Geothermal Properties

We follow the principles of the "successful efforts" method of accounting for our oil and natural gas exploration and evaluation activities.

For exploration and exploratory-type stratigraphic test wells, costs directly associated with the drilling of those wells are initially capitalized as assets under construction within oil and gas properties, pending determination of whether potentially economically viable oil and gas reserves have been discovered by the drilling effort.

Such estimates and assumptions may change as new information becomes available. If we do not discover potentially economically viable oil and gas quantities in a well, the well costs are expensed as a dry hole and are reported in exploration expense.

Provision for the Impairment of Loans and Receivables

Provision for the impairment of receivables is maintained at a level considered adequate to provide for potentially uncollectible receivables. We assess specifically at each balance sheet date whether there is objective evidence that a financial asset is impaired (uncollectible).

The level of provision is based on past collection experience and other factors that may affect collectability.

If there is objective evidence of impairment, timing and collectible amounts are estimated based on historical loss data. Loans and receivables written off are based on our decisions that the financial assets are uncollectible or cannot be realized regardless of actions taken. The timing and amount of provision for doubtful accounts recorded in each period may differ based on the judgments and estimates that have been used.

Due from the Government

We recognize amounts due from the Government for cost subsidies for certain fuel products, 3kg LPG cylinders and marketing fees in relation to the Government's share of crude oil, natural gas and LNG. We make an estimation of the amount due from the Government based on the actual delivery volume parameter and rates based on government regulations. The amount is subject to audit and approval by the BPK. The actual results may be different to the amounts recognized.

Depreciation, Estimate of Residual Values and Useful Lives of Fixed Assets

The useful lives of our investment properties and fixed assets are estimated based on the period over which the asset is expected to be available for use. Such estimation is based on a collective assessment of similar businesses, internal technical evaluations and experience with similar assets.

Deferred Tax Assets

Deferred tax assets are recognized only where it is considered more likely than not that they will be recovered, which is dependent on our assessment of the generation of sufficient future taxable profits.

Provision for Decommissioning and Site Restoration

We are required to carry out future decommissioning of oil and gas production facilities and pipelines at the end of their economic lives. Our largest decommissioning obligations relate to the plugging and abandonment of wells and the removal and disposal of oil and gas platforms and pipelines in our contract areas.

Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public

expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the related asset and could have a material impact on our consolidated financial statements.

Overview of Certain Key Line Items

Sales and Other Operating Revenues

Our sales and other operating revenues are primarily derived from domestic sales of crude oil, natural gas, geothermal energy and refined oil products. We also derive revenues from subsidy reimbursements from the Government for subsidized fuel products, additional amounts from the Government for the difference between the formula price and the government price of crude, export sales of crude oil, natural gas and oil products, marketing fees and revenues from our other operating activities.

Domestic sales of crude oil, natural gas, geothermal energy and oil products. Revenue from the production of crude oil and natural gas are recognized on the basis of the provisional entitlements method at the point of lifting. Differences between the actual liftings of crude oil and natural gas result in a receivable when final entitlements exceed liftings of crude oil and gas (i.e. an underlifting position) and in a payable when lifting of crude oil and natural gas exceed final entitlements (i.e. an overlifting position). Underlifting and overlifting volumes are valued based on the annual weighted average ICP for crude oil and price as determined in the respective sale and purchase contract for natural gas.

In 2016, 2017, 2018 and the three months ended March 31, 2019, domestic sales of crude oil, natural gas, geothermal energy and oil products represented 90.0%, 86.5%, 77.2% and 81.4%, respectively, of our total sales and other operating revenues. The largest component of our domestic sales of these products relates to the retail sale of automotive diesel oil and assignment motor gasoline under our PSO mandate as further described below. The balance is composed of domestic sales of other products.

In 2016, 2017 and 2018 and in the three months ended March 31, 2019, 32.0%, 27.5%, 26.5% and 30.3%, respectively, of our sales and other operating revenues (excluding marketing fees) were derived from the distribution of our various fuel products pursuant to our PSO mandate from the Government. For the period 2017 to 2018 our total sales and other operating revenues increased due to higher sales volumes and higher MOPS while the quantity and price of subsidized fuel products remained largely unchanged. For subsidized fuel and LPG in 3kg cylinders distributed under our PSO mandate, we receive both the retail price from the consumer as well as a cost subsidy reimbursement from the Government. See "Business — Pertamina Downstream Business — PSO" for a description of the PSO system and a description of how such cost subsidy reimbursements are determined.

While domestic sales of crude oil, natural gas, geothermal energy and oil products declined as a percentage of our total sales and other operating revenues between 2016 and 2018, our subsidy reimbursements from the government increased as a percentage of our sales and other operating revenues over the same period. See "— Subsidy reimbursements from the Government." In addition, in 2018, subsidy reimbursements that we received from the Government for the distribution of PSO fuel products were insufficient to cover our costs of production and distribution of those products and, pursuant to PR 43/2018 (as defined below), we received additional amounts from the Government to compensate us for the difference between the formula price and the government price of crude oil. In 2016, 2017, 2018 and in the three months ended March 31, 2019, domestic sales of crude oil, natural gas, geothermal energy and oil products and subsidy reimbursements from the government accounted for 96.5%, 94.3%, 87.0% and 91.0% of our sales and other operating revenues, respectively. In

addition, in 2018 and for the three months ended March 31, 2019, domestic sales of crude oil, natural gas, geothermal energy and oil products and subsidy reimbursements from the government and revenues from other operating activities (which primarily comprised additional amounts from the Government to compensate us for the difference between the formula price and the government price of crude) accounted for 93.7% and 93.1% of our sales and other operating revenues, respectively.

See also "— Overview of Segment Results."

Subsidy reimbursements from the Government. We receive regular cost subsidy reimbursements from the Government for subsidized fuel and LPG we distribute under our PSO mandate. These reimbursements represented 6.5%, 7.8%, 9.7% and 9.6% of our sales and other operating revenues in 2016, 2017, 2018 and the three months ended March 31, 2019, respectively. Our reimbursements were higher in 2017 as they were primarily driven by increased subsidy reimbursements received for sales of LPG in 3kg cylinders and in 2018 as they were primarily driven by increased subsidy reimbursements received for sales of certain fuel products, kerosene and LPG in 3kg cylinders.

Export of crude oil, natural gas and oil products. We export some of the oil products and crude oil we produce to foreign markets. In 2016, 2017, 2018 and the three months ended March 31, 2019, these sales represented 2.4%, 4.1%, 6.3% and 6.8%, respectively, of our sales and other operating revenues.

We also derive sales and other operating revenues from marketing fees and from our other operating activities. In 2016, 2017, 2018 and the three months ended March 31, 2019, the most significant contributions to revenue from our other operating activities came from shipping services, upstream support services, disparity of selling price and upstream support services, respectively.

In our upstream segment, we derive sales and other operating revenues primarily from exploration, drilling, development and production of crude oil, natural gas and geothermal energy, provision of technology services and drilling services primarily within Indonesia. In order to achieve upstream segment growth, we seek to increase production and to increase our number of new oil and gas reserves through improved oil recovery and enhanced oil recovery for existing assets and acquisitions of oil and gas blocks.

In our downstream segment, we derive sales and other operating revenues primarily from domestic sales of oil products and subsidies from the Government in relation to the distribution of certain subsidized fuel products and LPG in 3kg cylinders. We also derive sales and other operating revenues from sales of non-subsidized fuel products, LPG in 12kg and 50kg cylinders, non-assignment LPG in 3kg, 5.5kg, and 12kg cylinders and other non-fuel products.

Revenues from other operating activities. Revenues from other operating activities comprises revenues from other business services, such as natural gas transport, upstream support, shipping, insurance, and health and hospital services. In addition, in 2018, revenues from other operating activities primarily comprised one-time additional amounts received from the Government in relation to Government-regulated fuel prices, which is detailed below.

In 2018, PR 43/2018 amended Article 14 paragraph (8) of Presidential Regulation No. 191 of 2014. PR 43/2018 authorized the Minister of Energy and Mineral Resources to set the retail price for automotive diesel oil distributed under the PSO mandate at a level that is different from the retail price determined under the statutory subsidy reimbursement formula. The factors that PR 43/2018 requires the Minister of Energy and Mineral Resources to consider in exercising this authority include the Government's financial capacity, retail consumer purchasing power, and general economic and social conditions. PR 43/2018 also grants the Minister of Finance discretion to set additional policies, in

coordination with the Minister of Energy and Mineral Resources and the Minister of State-Owned Enterprises, to address revenue surpluses or deficits encountered by an entity with a PSO mandate due to fluctuations in the retail price of fuel. In 2018, we received US$3,905.5 million relating to the difference between the formula price and the government price of crude oil as a result of the Government's exercise of its authority under PR 43/2018.

Costs of Sales and Other Direct Costs

Cost of sales and other direct costs consist of cost of goods sold, which is comprised of production costs and purchases of oil products and other products, upstream production and lifting costs, exploration costs and expenses relating to other operating activities.

In 2016, 2017, 2018 and the three months ended March 31, 2019, cost of goods sold accounted for 86.5%, 88.2%, 87.8% and 85.2%, respectively, of our total cost of sales and other direct costs. The key components in cost of goods sold are described below.

Production costs. Production costs primarily represent costs related to the purchase of crude oil as feedstock for our refining operations, which we classify as direct materials. We import crude oil under term as well as spot contracts. The cost of importing crude oil accounts for a very substantial portion of our production costs, and is principally affected by the price and the quantity of crude oil we import. The quantity of crude oil we import typically increases as a result of increases in the amount of domestic crude oil which the Government is entitled to receive under production sharing arrangements and cooperation contracts, which we process on its behalf. Our production costs also include certain overhead costs, including supporting materials, rent, depreciation, salaries, wages and other employee benefits, utilities, infrastructure and fuel, customs and duties, maintenance and repairs, freight and transportation, materials and equipment, professional services, overhead and business travel, in each case directly related to production. Production costs represented 61.4%, 57.6%, 56.1% and 54.6% of our total cost of goods sold in 2016, 2017, 2018 and the three months ended March 31, 2019, respectively.

Purchases of oil products and others. In order to supplement the oil and other petrochemical products we produce and meet domestic demand, we import some of these products from foreign sources, including assignment motor gasoline, automotive diesel oil, industrial and marine fuel oil and other oil products, and we also make domestic purchases of other oil products, and geothermal energy. The related costs are recorded under this category. The costs of importing automotive diesel oil, other oil products (such as asphalt, avtur, Pertamax, butane and propane) and motor gasoline comprise a significant portion of these costs and typically increase when Indonesia's domestic fuel consumption exceeds domestic fuel production. Purchases of oil products and others represented 39.0%, 44.8%, 44.7% and 46.2% of our total cost of goods sold in 2016, 2017, 2018 and the three months ended March 31, 2019, respectively.

Our cost of sales and other direct costs represented 76.0%, 81.8%, 84.1% and 83.5% of our sales and other operating revenue in 2016, 2017, 2018 and the three months ended March 31, 2019, respectively. Our cost of sales and other direct costs as a percentage of sales and other operating revenue is typically higher during periods of higher crude oil prices because the pricing formulae on our subsidized fuel products generally do not allow us to pass on all of our increased costs to consumers, nor do the subsidies we receive from the Government completely cover such increases. In 2018, to address the shortfall between the subsidy reimbursements we receive from the Government for fuel products distributed under our PSO mandate and the higher cost of crude oil feedstock due to higher prices set by the Government, we received additional amounts from the Government for the difference between the formula price and the government price of crude oil.

Operating Expenses and Other Non-Operating Income/(Expenses) — Net

Operating expenses and other non-operating income/(expenses) — net represents the balance for a given period of certain factors affecting our results of operations and is defined as the sum of the following income statement line items: (i) selling and marketing expenses; (ii) general and administrative expenses; (iii) gain/loss on foreign exchange — net; (iv) finance income; (v) finance costs; (vi) share in net profit of associates and joint venture; and (vii) other expenses — net.

Selling and marketing expenses are primarily incurred in connection with freight and transportation, salaries, wages and other employee benefits, depreciation of fixed assets used in our selling, and LPG filling fees. General and administrative expenses primarily include salaries, wages and other employee benefits, taxes, retributions and penalties, and professional services and others, which comprises depreciation, depletion and amortization, rental, material and equipment, maintenance and repair, training, education and recruitment, business travel and other expenses. Other expenses — net is a general line item for other expenses and other income, which varies from year to year. For 2016 and 2017, other expenses — net primarily included provisions for tax disputes, provisions for impairment of certain assets such as oil and gas property, provision for impairment of goodwill, tax refund and final income tax asset revaluation. For 2018, other expenses — net primarily included provisions for impairment of certain assets such as oil and gas assets, decrease in value of investments in oil and gas blocks and tax penalties. For the three months ended March 31, 2019, other expenses — net primarily included decrease in value of investments in oil and gas blocks, provision for impairment of oil and gas assets and income from contract and material penalties and claims. Other income typically comprises income from contract and material penalties and claims, gains on adjustment of fair value of other investments and rental income.

Income Tax Expense — Net

We have been subject to corporate income tax at the rate of 25% since 2010. As our subsidiaries are taxed on an individual basis, in addition to the taxes that we are subject to on a consolidated basis, our effective tax rates (calculated as income tax expense — net divided by profit before income tax expense) for 2016, 2017, 2018 and for the three months ended March 31, 2019, were 35.1%, 30.2%, 52.6% and 52.0%, respectively. Income tax expense — net is net of deferred income tax benefits and expenses.

Profit for the Period/Year After the Effect of Merging Entity's Income Adjustment

Our profit for the period/year after the effect of merging entity's income adjustment is attributable to owners of the parent and non-controlling interests which are the interests of third parties in the equity of our subsidiaries which are not wholly owned by us. Our profit for the period/year after the effect of merging entity's income adjustment attributable to owners of the parent entity is our net income (including PGN) and represented 105.5%, 103.2%, 101.8% and 100.0% of our profit for the period/year before the effect of merging entity's income adjustment attributable to owners of the parent entity in 2016, 2017, 2018 and the three months ended March 31, 2019, respectively.

Overview of Segment Results

We have three operating segments: upstream, downstream and others. The operating segment which we classify as "others" consists of office and house rentals, hotel operation, air transportation services, health services and operation of hospitals, investment management, gas transportation services, human resources development services and insurance services. Our gas and new and renewable energy business activities are also grouped into our "others" segment

Our segment results are derived from our total segment revenues, after deducting total costs of sales and other direct costs, selling and marketing expenses and general and administrative expenses relating to such segments. We eliminate intercompany balances and transactions to derive our total consolidated segment revenues and results after eliminations, however we believe that our total consolidated segment revenues are an indicative measure of our performance as our intercompany transactions (for example, sales of crude oil from our upstream segment to our downstream segment for use as feedstock) are generally entered into on arm's length terms. Our segment revenues and results are presented in Note 42 to the consolidated financial statements, which are included elsewhere in this Offering Memorandum.

Results of Operations

Unless otherwise indicated, our results of operations are presented and discussed below on a consolidated basis.

The following table provides a breakdown of our profit for the period/year after the effect of merging entity's income adjustment by showing each item in U.S. dollar amounts and as a percentage of sales and other operating revenue for the periods indicated. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in this Offering Memorandum.

	For the Years Ended December 31,						For the Three-Month Periods Ended March 31,			
	2016		2017		2018		2018		2019	
							(Unaudited)			
	(US$ in millions, except percentages)									
		%		%		%		%		%
Total sales and other operating revenue	39,811.9	100.0	46,000.7	100.0	57,933.6	100.0	13,131.9	100.0	12,670.2	100.0
Total cost of sales and other direct costs	(30,263.7)	76.0	(37,625.2)	81.8	(48,714.1)	84.1	(11,220.0)	85.4	(10,577.2)	83.5
Total operating expenses and other non-operating income/(expenses)[1]	(4,199.4)	10.5	(4,508.3)	9.8	(3,489.9)	6.0	(494.5)	3.8	(899.3)	7.1
Profit before income tax	5,348.9	13.4	3,867.2	8.4	5,729.6	9.9	1,417.4	10.8	1,193.6	9.4
Income tax expense — Net	(1,877.6)	4.7	(1,166.8)	2.5	(3,013.2)	5.2	729.6	5.6	(620.3)	4.9
Profit for the period/ year after the effect of merging entity's income adjustment	3,471.2	8.7	2,700.4	5.9	2,716.4	4.7	687.8	5.2	573.4	4.5

Note:

(1) Comprised of selling and marketing expenses, general and administrative expenses, gain (loss) on foreign exchange — net, finance income, finance costs, share in net profit of associates and joint venture, and other expenses — net.

The following tables provide a breakdown of our sales (before elimination of inter-segment sales and expenses) and the results for our upstream and downstream segments for the periods indicated. See "Business — Pertamina Upstream Business" and "Business — Pertamina Downstream Business" for a description of our upstream and downstream segments. This table should be read together with our consolidated financial statements, including the notes thereto, appearing elsewhere in this Offering Memorandum.

Upstream

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
External upstream sales	3,542.5	4,489.3	7,054.5	1,914.6	1,671.9
Inter-segment sales	2,729.7	3,477.0	5,498.1	880.4	1,350.9
Total upstream segment revenues	6,272.3	7,966.3	12,552.6	2,795.0	3,022.9
Upstream segment results	2,065.7	3,327.9	5,960.6	1,272.9	1,368.7

Downstream

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
External downstream sales	32,337.2	37,000.6	45,691.6	9,979.4	10,004.3
Inter-segment sales	140.5	372.2	399.7	26.3	218.9
Total downstream segment revenues	32,477.7	37,372.7	46,091.3	10,005.7	10,223.2
Downstream segment results	4,176.2	1,282.2	(286.8)	(28.0)	(160.4)

The three-month period ended March 31, 2019 compared with the three-month period ended March 31, 2018

Sales and Other Operating Revenues

In the three months ended March 31, 2019, our sales and other operating revenues decreased by US$461.7 million, or 3.5%, to US$12,670.2 million from US$13,131.9 million in the three months ended March 31, 2018. This decrease was primarily due to an decrease in subsidy reimbursements from the Government and a decrease in domestic sales of crude oil, natural gas, geothermal energy and oil products because of the lower selling prices of certain types of our products. The average price of the ICP in March 2018 was US$63.02 per barrel while in March 2019 it was US$60.49 per barrel and the average price of MOPS PSA in March 2018 was US$77.27 per barrel while in March 2019 it was US$72.17 per barrel. This decrease was partially offset by an increase in the export of crude oil, natural gas and oil products.

In our upstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$227.9 million, or 8.2%, to US$3,022.9 million from US$2,795.0 million in the three months ended March 31, 2018. This increase was primarily due to higher sales volume, particularly from the sale of automotive diesel oil.

In our downstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$217.5 million, or 2.2%, to US$10,223.2 million from

US$10,005.7 million in the three months ended March 31, 2018. This increase was due to higher sales volume of our oil products, which reached 21.43 million KL in 2019 compared to 20.82 million KL in 2018, driven primarily by the sale of motor gasoline and automotive diesel oil.

Cost of Sales and Other Direct Costs

In the three months ended March 31, 2019, our cost of sales and other direct costs decreased by US$642.8 million, or 5.7%, to US$10,577.2 million from US$11,220.0 million in the three months ended March 31, 2018. This decrease was primarily due to a decrease in our cost of goods sold by US$618.9 million, or 6.4%, from US$9,632.0 million in the three months ended March 31, 2018 to US$9,013.1 million in the three months ended March 31, 2019 as a result of lower domestic crude oil prices set by the Government, which reduced our direct material costs as the majority of our feedstock was sourced domestically, a decrease in upstream production and lifting costs by US$63.2 million, or 5.2%, from US$1,224.1 million in the three months ended March 31, 2018 to US$1,160.9 million in the three months ended March 31, 2019, as well as a decrease in exploration costs by US$38.1 million or 59.7% from US$63.8 million in the three months ended March 31, 2018 to US$25.8 million in the three months ended March 31, 2019. For the same reasons, cost of sales and other direct costs as a percentage of revenue decreased from 85.4% in the three months ended March 31, 2018 to 83.5% in the three months ended March 31, 2019.

Segment Results

In the three months ended March 31, 2019, our consolidated segment results after eliminations decreased by US$84.2 million, or 6.3%, to US$1,252.2 million from US$1,336.4 million in the three months ended March 31, 2018. Our consolidated segment results after eliminations as a percentage of our sales and other operating revenues for the three months ended March 31, 2019 was 9.9% compared to 10.2% for the three months ended March 31, 2018 primarily due to an increase in production costs, as a result of lower selling prices set by the Government.

In the three months ended March 31, 2019, in our upstream segment, our results before eliminations increased by US$95.8 million, or 7.5%, to US$1,368.7 million from US$1,272.9 million in the three months ended March 31, 2018. This increase was primarily due to an increase in the volume of crude oil lifted in the three-month period ended March 31, 2019, as compared with the same period in 2018.

In our downstream segment, our results before eliminations amounted to a loss of US$160.4 million as compared to a loss of US$28.0 million in the three months ended March 31, 2018 primarily due to an increase in production costs, as a result of lower selling prices set by the Government.

Operating Expenses and other Non-Operating Expenses — net

In the three months ended March 31, 2019, we had operating expenses and other non-operating expenses — net of US$899.3 million compared to operating expenses and other non-operating expenses — net of US$494.5 million in the three months ended March 31, 2018, an increase of US$404.9 million or 81.9%. The increase was primarily attributable to (i) higher selling and marketing expenses primarily due to an increase in freight and transportation costs, an increase in LPG filling fee, an increase in costs for professional services, an increase in taxes, retributions and penalties, an increase in maintenance and repair costs and an increase in rental costs, (ii) higher finance costs due to increased indebtedness in the three months ended March 31, 2019 as compared to the three months ended March 31, 2018, (iii) higher general and administrative expenses primarily due to an increase in

salaries wages and other employee benefits, an increase in taxes, retributions and penalties and an increase in cost of materials and equipment and (iv) lower income from other expenses — net, which were partially offset by (y) a gain on foreign exchange — net, and (z) higher finance income.

Income Tax Expense — Net

In the three months ended March 31, 2019, our income tax expense — net decreased by US$109.4 million, or 15.0%, from US$729.6 million in the three months ended March 31, 2018 to US$620.3 million in the three months ended March 31, 2019. In the three months ended March 31, 2019, we had lower current tax expense due to lower income taxes paid by subsidiaries and lower consolidated corporate income tax expense in line with increased revenues as described above, as well as a deferred income tax expense as compared to a deferred income tax benefit in the three months ended March 31, 2018. For these reasons, our effective tax rate (calculated as income tax expense — net divided by profit before income tax expense) was 52.0% in the three months ended March 31, 2019 and 51.5% in the three months ended March 31, 2018.

Profit for the Period After the Effect of Merging Entity's Income Adjustment

For the reasons described above, in the three months ended March 31, 2019, our profit for the period after the effect of merging entity's income adjustment decreased by US$114.4 million, or 16.6%, to US$573.4 million from US$687.8 million in the three months ended March 31, 2018. As a percentage of our sales and other operating revenue, profit for the period after the effect of merging entity's income adjustment decreased from 5.2% in the three months ended March 31, 2018 to 4.5% in the three months ended March 31, 2019.

2018 compared with 2017

Sales and Other Operating Revenues

In 2018, our sales and other operating revenues increased by US$11,932.9 million, or 25.9%, to US$57,933.6 million from US$46,000.7 million in 2017. This increase was primarily due to an increase in domestic sales of non-subsidized fuel products as a result of higher sales volume. Sales volume of oil products in 2018 reached 88.72 million KL compared to 85.74 million KL in 2017, driven by strong domestic demand for our fuel products. The ICP actual price and published price increased in 2018 as compared to 2017. The average price of the ICP in 2018 was US$67.47 per barrel while in 2017 it was US$51.17 per barrel. The average price of MOPS PSA in 2018 was US$81.45 per barrel while in 2017 it was US$64.85 per barrel.

In our upstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$4,586.3 million, or 57.6%, to US$12,552.6 million from US$7,966.3 million in 2017. This increase was primarily due to an increase in the volume of crude oil lifted and an increase in the ICP in 2018 compared to 2017 as discussed above. In 2018, the volume of crude oil lifted was 129,231 mboe while in 2017 it was 111,555 mboe.

In our downstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$8,718.6 million, or 23.3%, to US$46,091.3 million from US$37,372.7 million in 2017. This increase was due to higher sales volume, particularly from non-subsidized fuel products, increase in the prices of non-subsidized fuel-products, as well as payments received from the Government in connection with the price differences in subsidized fuel products such as kerosene and those sold under the brand names "Premium" and "Solar/Biosolar."

Cost of Sales and Other Direct Costs

In 2018, our cost of sales and other direct costs increased by US$11,088.9 million, or 29.5%, to US$48,714.1 million from US$37,625.2 million in 2017. This increase was primarily due to an increase in our cost of goods sold by US$9,612.3 million, or 29.0%, to US$42,787.9 million in 2018 from US$33,175.7 million in 2017 as a result of increased feedstock requirements in line with our higher downstream sales volumes for the year, as well as higher Indonesian domestic crude oil prices set by the Government, which drove higher direct materials costs as the majority of our feedstock was sourced domestically. For the same reasons, cost of sales and other direct costs as a percentage of revenue increased to 84.1% in 2018 from 81.8% in 2017.

Segment Results

In 2018, our consolidated segment results after eliminations increased by US$1,060.3 million, or 20.4%, to US$6,246.7 million from US$5,186.4 million in 2017. Our consolidated segment results after eliminations as a percentage of our sales and other operating revenues for 2018 was 10.8% compared to 11.3% for 2017. This increase was primarily due to the higher selling prices of our upstream products as a result of an increase in the ICP in 2018 compared to 2017 as discussed above and the higher sales volumes in our downstream segment of products such as mixed LPG, non-subsidized fuel products sold under the brand name "Premium" and motor gasoline sold under the brand names "Pertalite (RON 90) and "Solar/Biosolar."

In 2018, in our upstream segment, our results before eliminations increased by US$2,632.7 million, or 79.1%, to US$5,960.6 million from US$3,327.9 million in 2017. This increase was primarily due to the higher selling prices of our products as a result of an increase in the ICP in 2018 compared to 2017 as discussed above.

In our downstream segment, our results before eliminations amounted to a loss of US$286.8 million as compared to income of US$1,282.2 million in 2017. In 2018, our cost of sales and other direct costs increased by US$11,088.9 million, or 29.5%, to US$48,714.1 million from US$37,625.2 million in 2017. This increase was primarily due to an increase in cost of goods sold by US$9,612.3 million, or 29.0%, to US$42,787.9 million in 2018 from US$33,175.7 million in 2017 as a result of an increase in prices of Indonesian and imported crude oil during 2018 as compared with 2017 prices, which drove higher direct materials costs and costs of imports of other oil products.

Operating Expenses and other Non-Operating Expenses — net

In 2018, we had operating expenses and other non-operating expenses — net of US$3,489.9 million compared to operating expenses and other non-operating expenses — net of US$4,508.3 million in 2017, a decrease of US$1,018.4 million or 22.6%. The decrease was primarily attributable to (i) lower other expenses — net primarily due to income, penalties and claims received under contracts with third parties, gains on fair value adjustments of other investments, and the absence of provisions for impairment of goodwill and for tax disputes and income tax asset revaluation in 2018 as compared to 2017, (ii) an increase in share in net profit of associates and joint ventures due to an amount of US$76.1 million generated by Seplat Petroleum Development Company plc, a company in M&P's group, (iii) lower general and administrative expenses due to lower salaries, wages and other employee benefits in line with a decrease in our number of permanent employees of 1,451 from 31,569 as at December 31, 2017 to 30,118 employees as at December 31, 2018, and (iv) higher finance income due to higher balances of time deposits during 2018 as compared to 2017, which were partially offset by (x) higher selling and marketing expenses, (y) a decrease in gain on foreign exchange — net, and (z) higher finance costs due to increased indebtedness in 2018.

Income Tax Expense — Net

In 2018, our income tax expense — net increased by US$1,846.4 million, or 158.2%, to US$3,013.2 million from US$1,166.8 million in 2017. In 2018, we had higher current tax expense due to higher income taxes paid by subsidiaries and higher consolidated corporate income tax expense in line with increased revenues as described above, as well as a deferred income tax expense as compared to a deferred income tax benefit in 2017. For these reasons, our effective tax rate[3] was 52.6% in 2018 and 30.2% in 2017. This increase was primarily due to the higher selling prices of our upstream products as a result of an increase in the ICP in 2018 compared to 2017 as discussed above, partially offset by increased taxation. This increase was primarily due to the higher selling prices of our upstream products as a result of an increase in the ICP

Profit for the Year After the Effect of Merging Entity's Income Adjustment

For the reasons described above, in 2018, our profit for the year after the effect of merging entity's income adjustment increased by US$16.0 million, or 0.6%, to US$2,716.4 million from US$2,700.4 million in 2017. As a percentage of our sales and other operating revenue, profit for the year after the effect of merging entity's income adjustment decreased from 5.9% in 2017 to 4.7% in 2018.

2017 compared with 2016

Sales and Other Operating Revenues

In 2017, our sales and other operating revenues increased by US$6,188.8 million, or 15.5%, to US$46,000.7 million from US$39,811.9 million in 2016. This increase was primarily due to an increase in domestic sales of non-subsidized fuel products, crude oil and geothermal energy as a result of higher sales volume and higher crude oil prices. Sales volume of oil products in 2017 reached 85.74 million KL compared to 81.95 million KL in 2016, driven by strong domestic demand for our fuel products and focused sales and marketing initiatives to increase sales of non-subsidized fuel products The ICP actual price and published price increased in 2017 as compared to 2016. The average price of the ICP in 2017 was US$51.17 per barrel while in 2016 it was US$40.16 per barrel. The average price of MOPS PSA in 2017 was US$64.85 per barrel while in 2016 it was US$52.08 per barrel.

In our upstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$1,694.0 million, or 27.0%, to US$7,966.3 million from US$6,272.3 million in 2016. This increase was primarily due to higher selling prices of our products as a result of an increase in the ICP in 2017 compared to 2016 as discussed above.

In our downstream segment, our total segment revenues before eliminations in connection with our accounts consolidation increased by US$4,895.0 million, or 15.1%, to US$37,372.7 million from US$32,477.7 million in 2016. This increase was due to higher sales volume from non-subsidized fuel products and higher selling prices of our products as a result of an increase in the ICP in 2017 compared to 2016 as discussed above.

Cost of Sales and Other Direct Costs

In 2017, our cost of sales and other direct costs increased by US$7,361.5 million, or 24.3%, to US$37,625.2 million from US$30,263.7 million in 2016. This increase was primarily due to an increase

3 The effective tax rate is calculated as income tax expense — net divided by profit before income tax.

in our cost of goods sold by US$6,994.7 million, or 26.7%, to US$33,175.7 million in 2017 from US$26,181.0 million in 2016 as a result of an increase in prices of Indonesian and imported crude oil during 2017 as compared with 2016 prices, which drove higher direct materials costs and costs of imports of other oil products. For the same reasons, cost of sales and other direct costs as a percentage of revenue increased to 81.8% in 2017 from 76.0% in 2016.

Segment Results

In 2017, our consolidated segment results after eliminations decreased by US$1,513.0 million, or 22.6%, to US$5,186.4 million from US$6,699.4 million in 2016. Our consolidated segment results after eliminations as a percentage of our sales and other operating revenues for 2017 was 11.3% compared to 16.8% for 2016 due to lower selling prices of certain types of our oil fuel and assignment oil fuel, which was partially offset by an increase in the selling prices for our upstream products in 2017 as compared to 2016.

In 2017, in our upstream segment, our results before eliminations increased by US$1,262.2 million, or 61.1%, to US$3,327.9 million from US$2,065.7 million in 2016. This increase was primarily due to our upstream segment revenues increasing from 2016 to 2017 as the selling prices for our upstream products increased in line with the increase in ICP, while our upstream costs and expenses did not increase significantly.

In 2017, in our downstream segment, our results before eliminations decreased by US$2,894.0 million, or 69.3%, to US$1,282.2 million from US$4,176.2 million in 2016. This was primarily due to lower selling prices of certain types of our oil fuel and assignment oil fuel, particularly motor gasoline and automotive diesel oil, which are set by the Government below market rates and not fully covered by Government subsidy reimbursements, as well as decreased margins from our sale of oil products as the spreads between ICP, which is a reference for the pricing of our crude oil purchases, and MOPS, which is a reference for the pricing of our oil product sales, generally decreased in line with the increase in ICP.

Operating Expenses and other Non-Operating Expenses — net

In 2017, we had operating expenses and other non-operating expenses — net of US$4,508.3 million compared to operating expenses and other non-operating expenses — net of US$4,199.4 million in 2016, an increase of US$308.9 million or 7.4%. The increase was primarily attributable to (i) higher salaries, wage and other employee benefits in line with an increase in our number of permanent employees in 2017, (ii) higher freight and transportation expenses due to higher fuel costs, (iii) lower finance income due to lower balances of time deposits during 2017 as compared to 2016 and (v) income tax asset revaluation associated with certain of our refineries.

Income Tax Expense — Net

In 2017, our income tax expense — net decreased by US$710.8 million, or 37.9%, to US$1,166.8 million from US$1,877.6 million in 2016 primarily due to lower current tax expense on lower profit before income tax in 2017 and an increase in deferred income tax benefit from a revaluation of certain refinery assets. Our effective tax rate[4] was 30.2% in 2017 and 35.1% in 2016.

Profit for the Year After the Effect of Merging Entity's Income Adjustment

For the reasons described above, in 2017, our profit for the year after the effect of merging entity's income adjustment decreased by US$770.8 million, or 22.2%, to US$2,700.4 million from

4 The effective tax rate is calculated as income tax expense — net divided by profit before income tax.

US$3,471.2 million in 2016. As a percentage of our sales and other operating revenue, profit for the year after the effect of merging entity's income adjustment decreased from 8.7% in 2016 to 5.9% in 2017.

Liquidity and Capital Resources

Our principal sources of liquidity consist of cash flows generated from operating activities, bank facilities and other debt financing, and our existing cash, cash equivalents and bank deposits. We believe that our future cash flows from operations, borrowing capacity (including under the Program) and cash and cash equivalents in hand will be sufficient to fund our planned capital expenditures and investments, debt maturities and our present working capital requirements. We regularly evaluate our current and future financing needs and may, depending on market conditions, access the capital markets opportunistically from time to time to strengthen our capital position, manage our debt maturity profile and provide us with additional liquidity. Our ability to obtain adequate financing may be limited by our financial condition and results of operations and the liquidity of international and domestic financial markets.

The following table sets forth a summary of our consolidated cash flows for the periods indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Net cash generated from operating activities	8,391.2	4,076.9	3,169.4	9.4	758.5
Net cash used in investing activities	(2,619.4)	(2,379.3)	(3,503.8)	(369.1)	(637.4)
Net cash generated from (used in) financing activities	(3,479.6)	(1,972.2)	3,268.7	(173.0)	(956.2)
Net increase (decrease) in cash and cash equivalents	2,292.3	(274.6)	2,934.3	(532.7)	(835.1)
Effect of exchange rate changes on cash and cash equivalents	20.7	(37.2)	(231.8)	(44.7)	44.9
Cash and cash equivalents at beginning of the year	4,408.7	6,721.6	6,409.8	6,409.8	9,112.3
Cash and cash equivalents at end of the year	6,721.6	6,409.8	9,112.3	5,832.5	8,322.1

Net Cash Generated from Operating Activities

Net cash generated from operating activities includes funds provided by our operating activities and net cash inflows or outflows from changes in operating assets and liabilities.

Net cash generated from operating activities was US$758.5 million in the three-month period ended March 31, 2019, which consisted primarily of aggregate cash receipts from customers, the Government and a tax restitution of US$12,930.6 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$12,215.9 million. The increase in net cash generated from operating activities in the three-month period ended March 31, 2019, as compared to the same period in 2018, was primarily attributable to a decrease in cash payments to suppliers and to the Government.

Net cash generated from operating activities was US$9.4 million in the three-month period ended March 31, 2018, which consisted primarily of aggregate cash receipts from customers, the Government and a tax restitution of US$13,454.9 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$13,447.3 million.

Net cash generated from operating activities was US$3,169.4 million in 2018, which consisted primarily of aggregate cash receipts from customers, the Government and a tax restitution of US$56,869.2 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$53,836.3 million. The decrease in net cash generated from operating activities in 2018, as compared to 2017, was primarily attributable to an increase in cash payments to suppliers and to the Government for its share of crude oil supplied to our refineries due to an increase in the average ICP from US$51.17 per barrel in 2017 to US$67.47 per barrel in 2018, which was partially offset by an increase in cash receipts from customers and from the Government.

Net cash generated from operating activities was US$4,076.9 million in 2017, which consisted primarily of aggregate cash receipts from customers, the Government and tax restitution of US$44,624.8 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$40,427.5 million. The decrease in net cash generated from operating activities in 2017, as compared to 2016, was primarily attributable to a reduction in cash receipts from customers primarily as a result of lower sales of certain subsidized fuel products, as well as an increase in cash payments to the Government for its share of crude oil supplied to our refineries due to an increase in the average ICP from US$40.16 per barrel in 2016 to US$51.17 per barrel in 2017.

Net cash generated from operating activities was US$8,391.2 million in 2016, which consisted of aggregate cash receipts from customers, the Government and tax restitution of US$46,485.3 million offset by aggregate cash payments to suppliers, the Government, for corporate income taxes and to employees and management of US$37,715.8 million. The increase in net cash flows from operating activities in 2016, as compared to 2015, was primarily attributable to lower payments to suppliers due to cost savings measures successfully implemented and to the Government due to the decrease in the average ICP price from US$50.00 per barrel in 2015 to US$40.16 per barrel in 2016, which was partially offset by a decrease in cash receipts from customers and the Government as a result of lower downstream sales.

Net Cash Used in Investing Activities

Net cash used in investing activities was US$637.4 million in the three months ended March 31, 2019, US$369.1 million in the three months ended March 31, 2018, US$3,503.8 million in 2018, US$2,379.3 million in 2017 and US$2,619.4 million in 2016. These amounts are primarily attributable to (i) purchases of fixed assets of US$196.0 million in the three months ended March 31, 2019, US$163.5 million in the three months ended March 31, 2018, US$1,288.0 million in 2018, US$981.9 million in 2017 and US$1,012.7 million in 2016, (ii) purchases of oil and gas and geothermal properties of US$421.6 million in the three months ended March 31, 2019, US$257.7 million in the three months ended March 31, 2018, US$1,482.5 million in 2018, US$892.0 million in 2017 and US$1,365.1 million in 2016, (iii) placements in short- and long-term investments of US$43.9 million in the three months ended March 31, 2019, US$58.1 million in the three months ended March 31, 2018, US$1,299.8 million in 2018, US$886.3 million in 2017 and US$479.3 million in 2016 and (iv) dividends received from associates of US$0.006 million in the three months ended March 31, 2019, US$2.3 million in the three months ended March 31, 2018, US$214.1 million in 2018, US$81.6 million in 2017 and US$233.6 million in 2016. In 2018, we also had cash receipts from other investing activities of US$262.2 million related to the settlement and receipt of other long-term receivables, including cash receipts from PGN's acquisition from the Issuer of a 51.0% stake in Pertagas.

Net Cash Generated from (Used in) Financing Activities

We recorded net cash used in financing activities of US$956.2 million in the three months ended March 31, 2019, US$173.0 million in the three months ended March 31, 2018, US$1,972.2 million in

2017 and US$3,479.6 million in 2016. We recorded net cash generated from financing activities of US$3,268.7 million in 2018.

Our net cash used in financing activities of US$956.2 million in the three months ended March 31, 2019, consisted primarily of proceeds from short-term loans of US$1,079.3 million and proceeds from long-term loans of US$51.3 million. This was offset by repayments of short-term loans of US$1,885.7 million, repayments of long-term loans of US$182.2 million, payments of finance costs of US$18.1 million and placement of restricted cash of US$0.7 million.

Our net cash used in financing activities of US$173.0 million in the three months ended March 31, 2018, consisted primarily of proceeds from short-term loans of US$830.3 million, proceeds from long-term loans of US$44.4 million and receipts from restricted cash of US$0.1 million. This was offset by repayments of short-term loans of US$830.3 million, repayments of long-term loans of US$201.8 million and payments of finance costs of US$15.9 million.

Our net cash generated from financing activities of US$3,268.7 million in 2018, consisted primarily of proceeds from short-term loans of US$9,489.2 million and proceeds from bond issuance of US$734.4 million. This was partially offset by repayments of short-term loans of US$5,583.3 million, payment of a dividend of US$585.8 million to the Government, payment of finance costs of US$538.5 million, repayments of long-term loans of US$465.4 million, a repayment of bonds of US$37.6 million and placement of restricted cash of US$0.3 million.

Our net cash used in financing activities of US$1,972.2 million in 2017 consisted primarily of proceeds from short-term loans of US$4,039.5 million and proceeds from long-term loans of US$1,288.2 million. This was partially offset by repayments of short-term loans of US$3,786.7 million, repayments of long-term loans of US$2,109.0 million, payment of a dividend of US$867.8 million to the Government, payment of finance costs of US$523.1 million and placement of restricted cash of US$13.2 million.

Our net cash used in financing activities of US$3,479.6 million in 2016 consisted primarily of proceeds from short-term loans of US$2,377.3 million and proceeds from long-term loans of US$1,674.4 million. This was partially offset by repayments of short-term loans of US$4,057.9 million, repayments of long-term loans of US$2,248.4 million, payment of a dividend of US$554.9 million to the Government, payment of finance costs of US$530.8 million, repayment of bonds of US$139.8 million and receipt from restricted cash of US$0.4 million.

Indebtedness

The following table shows the amount of our total consolidated short-term loans, long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans, and bonds payables outstanding as of December 31, 2016, 2017 and 2018 and as of March 31, 2019.

	As of December 31,			As of March 31,
	2016	2017	2018	2019
				(Unaudited)
	(US$ in millions)			
Short-term loans	230.3	452.9	4,347.0	3,671.4
Long-term liabilities — bank loans — net (including current portion)	3,226.6	2,268.6	2,065.9	1,931.9
Due to the Government — two-step loans[(1)]	665.9	716.8	738.5	732.7
Bonds payables	9,772.7	10,385.9	11,094.1	11,099.8
Total debt	13,895.5	13,824.2	18,245.5	17,435.8

Note:

(1) Includes Government-channeled financings obtained from the Overseas Economic Cooperation Fund Japan, the Japan International Cooperation Agency, the International Bank for Reconstruction and Development and the Japan Bank for International Cooperation. See Notes 18b, 18c, 18d, 18g, 18h and 18i of our consolidated financial statements for more information on the two-step loans.

As of December 31, 2018, the current portion of our long-term bank loans without taking account any issuance costs-net was US$420.6 million and the non-current portion was US$1,805.3 million. As of March 31, 2019, the current portion of our long-term bank loans without taking account any issuance costs-net was US$423.3 million and the non-current portion was US$1,651.9 million.

Short-Term Loans

As of December 31, 2018 and March 31, 2019, we have access to unsecured short-term revolving credit facilities in the form of letters of credit post import financing of up to an aggregate US$9,987.0 million and US$10,507.0 million and Rp. 2,000.0 million, respectively. These facilities are denominated in U.S. dollars and Rupiah and provided by 24 Indonesian and international banks, including Mandiri (Persero) Tbk., PT Bank Negara Indonesia (Persero) Tbk., PT Bank Rakyat Indonesia (Persero) Tbk., PT Bank Central Asia Tbk., PT Bank Permata Tbk., PT Bank Bukopin Tbk, PT Bank HSBC Indonesia, UOB Indonesia, Standard Chartered Indonesia, PT Bank Tabungan Pensiunan Nasional (which was previously known as PT Bank Sumitomo Mitsui Indonesia), The Bank of Tokyo-Mitsubishi UFJ, LTD., PT Bank DBS Indonesia, PT Bank Mizuho Indonesia, PT Bank Maybank Indonesia Tbk, ANZ Jakarta, Deutsche Bank AG Jakarta, Banque Nationale de Paris Paribas, Singapore Branch, Crédit Agricole Corporate Investment Bank, Singapore Branch, Natixis, Singapore Branch, Citibank, N.A. Indonesia, JP Morgan Singapore Pte. Ltd., Societe Generale, Sumitomo Mitsui Banking Corporation, Singapore Branch and Intesa Sanpaolo Singapore, which we use in connection with our trading activities, of which we have utilized cumulatively US$4,347.0 million as of December 31, 2018 and US$3,486.0 million as of March 31, 2019. Drawdowns from these facilities are subject to further approvals of the relevant financial institutions. These short-term revolving credit facilities will expire in accordance with their terms in the course of each financial year. We intend to enter into new revolving credit facilities with the same or new lenders and maintain access to up to US$1,964.0 million in aggregate of short-term revolving credit facilities during the course of the year.

The terms of our short-term revolving credit facilities include a number of customary covenants, undertakings and events of default that, among other things, restrict, our ability to create liens, sell assets, engage in different business activities or effect a consolidation or merger, subject to certain exceptions, and require us to provide certain financial information to our lenders. In addition, some facility agreements require that the Government of Indonesia continue to maintain a minimum percentage of ownership in our company, for example, 50.0% of our equity share capital, or the right to otherwise direct our policies or operations.

Long-term Liabilities — Bank Loans

Our long-term loans outstanding as of December 31, 2016, 2017 and 2018 and as of March 31, 2019 consisted of both Rupiah and foreign currency obligations. The following table shows the currency denomination of our outstanding long-term bank and two-step loans and bonds as of March 31, 2019.

	U.S. dollar (in millions)	Japanese Yen (in billions)
Total long-term liabilities — bank loans — net (including current portion), due to the Government — two-step loans and bonds	13,764.4	49.3

On July 2, 2019, we entered into a framework agreement with the Export-Import Bank of Korea ("EIBK"), as lender, pursuant to which EIBK agreed to make available funds of up to $1.5 billion by way of an uncommitted line of credit to enable us to make payments under certain contracts entered into by us and a Korean entity. We may utilize such funds by negotiating and entering into loan agreements under the framework agreement subject to certain conditions relating to the maximum commitment amount permitted under each individual loan facility depending on its use of proceeds. Once an amount has been utilized, such sum may not be reutilized under the framework agreement. The framework agreement contains customary representations, warranties, undertakings and events of default for an agreement of this nature. This framework agreement aims to fund our infrastructure projects, such as new refineries and expansion of existing plants, contribute to our downstream expansion drive and facilitate the involvement of South Korean companies as partners in our projects, including the RDMP and the Balikpapan refinery upgrade in east Kalimantan province. The line of credit is valid for two years and tenor of each individual loan facility cannot exceed 15 years.

In 2017, Etablissements Maurel et Prom entered into a US$600.0 million syndicated loan facility, as parent and guarantor, with two national banks and seven overseas banks, with The Bank of Tokyo Mitsubishi UFJ, Ltd., Hong Kong Branch acting as the facility agent, and PT Pertamina Internasional Eksplorasi dan Produksi ("PIEP") acting as the sponsor, for indebtedness refinancing. The syndicated loan facility bears interest at LIBOR plus 1.5% margin and must be repaid on a quarterly basis from March 2020 through to its maturity in December 2023. This syndicated loan facility is unsecured and requires that we provide certain information undertakings as well as financial covenants.

On October 19, 2016, we entered into a facility agreement with Sumitomo Mitsui Banking Corporation, as mandated lead arranger and bookrunner, the original lenders named therein as original lenders, Sumitomo Mitsui Banking Corporation Singapore Branch, as facility agent and Sumitomo Mitsui Banking Corporation (China) Limited as sinosure agent. Under the facility agreement, we are granted covered term loans of up to US$77.8 million and a commercial term loan of up to $13.7 million, to finance the acquisition of three medium range tankers and related equipment. Each utilization under the facility agreement is to be repaid in installments with final maturity dates falling seven to nine years after the date of drawdown. The loans carry interest rates of LIBOR plus a margin ranging between 1.0% and 1.2% per annum. The facilities agreement contains customary undertakings and events of default for a facility of this nature, subject to agreed exceptions, limitations and qualifications. In addition, we are required to maintain a Consolidated EBITDA to Consolidated Interest Payable ratio that is not less than 3.0 to 1.0 and ensure that our Consolidated Net Debt does not exceed 2.0 times our tangible net worth at the end of each half and full financial year.

On August 31, 2016, we entered into a facilities agreement with the Bank of Tokyo — Mitsubishi UFJ, Ltd. as the facility agent, BNP Paribas, Sumitomo Mitsui Banking Corporation, Citigroup Global Markets Singapore Pte. Ltd., DBS Bank Ltd., Mizuho Bank, Ltd., PT Bank Negara Indonesia (Persero), Tbk., Bank of Tokyo-Mitsubishi UFJ, Ltd., as the mandated lead arrangers and bookrunners, and the lenders that are party to that agreement from time to time. Under the facilities agreement, as amended on November 2, 2016, we are granted four facilities in an aggregate principal amount of term loans up to US$1.5 billion, which may be used for general corporate purposes (including in connection with any refinancing of existing indebtedness). Each utilization under the facilities agreement is to be repaid in installments with the final maturity date falling five years after the date of drawdown. The facilities carry an interest rate of LIBOR plus a margin ranging between 1.1% and 1.2% per annum. The facilities agreement contains customary undertakings and events of default for a facility of this nature, subject to agreed exceptions, limitations and qualifications. In addition, we are required to maintain a Consolidated EBITDA to Consolidated Interest Payable ratio that is not less than 3.0 to 1.0 and ensure that our Consolidated Net Debt does not exceed 2.0 times our tangible net worth at the end of each half and full financial year.

In December 2015, we entered into a US$150.0 million loan facility with PT Sarana Multi Infrastruktur (Persero). The loan facility bears interest at one, three or six months LIBOR plus a

margin of 1.65% per annum. The principal payment is due to be fully paid at the end of the facility in December 2025.

We have also received financing from the Government in the form of a two-step loan from the Overseas Economic Cooperation Fund ("OECF") Japan. The Government originally lent to OECF an amount of ¥11,816.0 million (US$104.9 million), pursuant to a loan agreement between the Government and OECF dated November 29, 1994. We, in turn, borrowed ¥1,172.9 million (US$10.4 million) from OECF under a two-step loan agreement dated May 7, 2007 among us as borrower, the Government as co-obligor and OECF as lender. The proceeds of this loan were used to finance the construction of the Airport Fuel Filling Depot of Ngurah Rai International Airport in Bali. The two-step loan matures 30 years from November 29, 1994, the date of the loan agreement between the Government and OECF. There is no collateral given by the Company for the two-step loan, as the Government remains the primary obligor of the loan. The two-step loan bears interest at 3.1% per annum. Any late principal payments will be subject to a 2% per annum penalty.

We have also received financing from the Government in the form of a two-step loan from the Japan International Cooperation Agency ("JICA"). The Government obtained a loan of ¥26,966.0 million (US$239.3 million) from JICA under which we were appointed as executing and implementing agency, pursuant to a loan agreement between the Government and JICA dated March 29, 2011. The loan is to be utilized for the implementation of the Lumut Balai geothermal power plant project. There is no collateral given by the Company for this two-step loan, as the Government remains the primary obligor of the loan. The two-step loan is available as two loan facilities, one of which is ¥25,834.0 million (US$229.3 million) and is related to the construction of the project and bears interest at 0.6% per annum and the other facility is ¥1,132.0 million (US$10.0 million) and is related to consultants for the project and bears interest at 0.02% per annum. Any late principal payments will be subject to a 2% per annum penalty.

We received financing from the Government in the form of a two-step loan from the World Bank's International Bank for Reconstruction and Development ("IBRD"). The Government obtained a loan of US$300.0 million from IBRD under which we were appointed as executing agency, pursuant to two loan agreements, each between the Government and IBRD dated December 5, 2011. One loan amounted to US$175.0 million and the other amounted to US$125.0 million. The loans are to be utilized for the implementation of the Ulubelu and Lahendong geothermal clean energy investment project. There is no collateral given by the Company for this two-step loan, as the Government remains the primary obligor of the loan. Repayment of the loan principal will be on a semi-annual basis, commencing on October 10, 2020 until October 10, 2035 for the US$175.0 million loan, and commencing on October 10, 2021 until April 10, 2051 for the US$125.0 million loan. The interest rate for the tranche of US$175.0 million is LIBOR plus 0.45% and an additional variance spread, and the interest rate for the tranche of US$125.0 million is 0.5%.

We received financing from the Government in the form of a two-step loan from the Japan Bank for International Cooperation ("JBIC"). On May 28, 2003, the Government obtained two loans consisting of ¥44,702.0 million (US$402.3 million) and ¥4,386.0 million (US$39.5 million), with interest rates of 1.45% and 1.25% per annum respectively. The loans are to be utilized for the implementation of the development of a gas transmission and pipeline from South Sumatra to West Java and a distribution pipeline in West Java.

We received financing from the Government in the form of a second two-step loan from IBRD. On April 3, 2006, the Government obtained a loan of US$80 million to finance a domestic gas market development project. The IBRD's interest rate to the Government is LIBOR plus 1.00% per annum.

On September 15, 2000, PGN and the Government entered into a loan agreement, which provides for the Government's relending of EIB loan proceeds not exceeding €70.0 million (US$81.0 million) to

PGN as part of the financing of the gas transmission and distribution project phase II. The loans consist of €44.3 million (US$51.3 million) and €10.3 million (US$11.9 million), with interest rates of 4.9% and 5.3% respectively.

Our bank loans are to finance our capital expenditures and to provide working capital. Our subsidiaries' long-term bank loans are collateralized by certain of our subsidiaries' assets such as receivables, inventories, long-term assets and other assets.

Bonds

As of March 31, 2019, we have issued US$1,000.0 million 2021 Notes, US$500.0 million 6.50% senior notes due 2041, US$1,250.0 million 2022 Notes (of which US$1,242.0 million 2022 Notes remains outstanding), US$1,250.0 million 6.00% notes due 2042, US$1,350.0 million 5.125% notes due 2024 and US$625.0 million 4.450% notes due 2024.

We established the Program on May 3, 2013 and increased the Program Limit from US$5,000 million to US$10,000 million in 2014. As of March 31, 2019, we have issued, under the Program, US$1,625.0 million 4.30% senior notes due 2023, US$1,625.0 million 5.625% senior notes due 2043, US$1,500 million 6.45% senior notes due 2044 and US$750.0 million 6.50% senior notes due 2048. We regularly evaluate our current and future financing needs and may opportunistically pursue financing opportunities from time to time, including through further issuances of Notes under the Program, if we consider market conditions to be favorable.

As of March 31, 2019, our subsidiary PGN has issued US$1,350.0 million senior notes 5.125% due 2024 and our subsidiary PT Saka Energi Indonesia has issued US$625.0 million senior notes 4.45% due 2024.

All of these notes are unsecured.

The interest rates on our long-term banks loans and bonds during 2017, 2018 and 2019 are set forth in the table below. All bonds were issued by the Issuer unless otherwise noted.

	2017	2018	2019
Rupiah long-term loans	7.25% – 13.00%	2.35% – 13.00%	2.35% – 13.00%
U.S. dollar long-term loans	1.37% – 3.51%	1.37% – 5.60%	1.37% – 5.60%
Senior notes due 2021	5.25%	5.25%	5.25%
Senior notes due 2041	6.50%	6.50%	6.50%
Senior notes due 2022	4.88%	4.88%	4.88%
Senior notes due 2042	6.00%	6.00%	6.00%
Senior notes due 2023	4.30%	4.30%	4.30%
Senior notes due 2043	5.63%	5.63%	5.63%
Senior notes due 2024[(1)]	4.45%	4.45%	4.45%
Senior notes due 2024[(1)]	5.13%	5.13%	5.13%
Senior notes due 2044	6.45%	6.45%	6.45%
Senior notes due 2048	n/a	6.50%	6.50%

Note:

(1) Issued by our subsidiaries.

Capital Expenditures

Our capital expenditures relate primarily to our exploration, development and production projects, to purchase interests in other companies engaged in exploration, development and production projects,

the maintenance and upgrading of our refineries and repayments of outstanding debt. Our principal sources of funding for our capital expenditures consist of cash flows generated from operating activities, project financing arrangements and other debt financing, and our existing cash, cash equivalents and bank deposits.

The following table sets out our actual capital expenditures by business segment for each of the years ended December 31, 2016, 2017 and 2018 and for the three-month periods ended March 31, 2018 and 2019.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(US$ in millions)	(Unaudited)	
Upstream	1,579.2	3,672.7	3,110.8	23.2	494.5
Downstream	801.3	1,529.1	1,135.6	229.6	171.6
Others	644.5	221.4	287.1	50.9	2.7
Total	**3,025.0**	**5,423.2**	**4,533.5**	**303.7**	**668.8**

We consider any purchase orders which are outstanding as of a fiscal year or period to be our outstanding capital expenditure commitments for such year or period. In addition, in 2016, we had a one-time increase in upstream capital expenditures due to a capital injection of US$2.8 billion into PIEP, which was used to partially finance our acquisition of Etablissements Maurel et Prom ("M&P"), a French multinational oil and gas company listed on the Paris Stock Exchange with exploration and production assets in Africa, Europe and Latin America. In 2017 and 2018, our capital expenditures were US$5.4 billion and US$4.5 billion, respectively. Our capital expenditure in 2017 included expenditures for the acquisitions of M&P, the Mahakam block and the Offshore North West Java block in 2017.

The following table sets out our budgeted capital expenditures by business sector for the year ending December 31, 2019 excluding PGN. Our budgeted capital expenditures include amounts budgeted for upstream exploration and drilling, investments in grass roots refineries, upgrades to existing refineries and gas infrastructure and potential growth through domestic and international acquisitions in each year and other uncommitted capital expenditures. This information reflects our current expectations only and our actual capital expenditures in any such year may differ materially from the projections set out below. See "Risk Factors — Risks Relating to Our Company — We may be unable to accomplish our development plans on schedule or within our budgeted costs or that these plans, if completed, will achieve our development aims" and "Risk Factors — Risks Relating to our Company — Our business is capital intensive, and if we are unable to obtain financing on reasonable terms to fund future capital expenditures, we may be unable to implement our development plans."

	For the Year Ending December 31, 2019
	(US$ in millions)
Upstream	
Oil and gas exploration and production	2,412.8
Geothermal	152.6
Drilling services	33.0
Total	2,598.4
Downstream	
Refining	574.3
Marketing and trading	494.2
Shipping	6.5
Total	1,075.0
Gas	416.0
Non-Core businesses	110.6
Total	4,200.0

As of March 31, 2019, our unrealized total outstanding capital expenditure commitments amounted to US$3,709.4 million.

We expect our capital expenditures for 2020 to be significantly higher than 2019 in terms of budgeted amount and intended purposes, based on our current estimates of various major project development timelines and subject to the finalization of, and any subsequent updates to, our annual budget for 2020.

We expect that investment in oil and gas exploration and development and our refineries will continue to represent the majority of our capital expenditures. Such capital expenditures are expected to relate to domestic and international acquisitions of new fields and development of existing fields or interests therein and expansion of our existing refineries and construction of new refineries in East Java and Balongan. In our upstream business sector, we intend to boost levels of production and to increase the number of new oil and gas reserves organically through recovery of existing assets or inorganically through mergers and acquisitions of oils and gas blocks both at home and abroad. In our downstream business sector, we also intend to expand our shipping fleet, construct a refrigerated LPG terminal and expand our network of retail fuel stations which are owned and operated by us. For more information, see "Business — Pertamina Upstream Business — Upstream Strategy" and "Business — Pertamina Downstream Business — Downstream Strategy."

We plan to fund the capital and related expenditures principally through cash provided by operating activities and long-term debt. See "Risk Factors — Risks Relating to Our Company — We may seek to incur additional indebtedness in the future, which could adversely affect our business or financial condition."

Contractual Obligations

The following table summarizes our contractual financial liabilities (including anticipated interest payable) and operating lease commitments as of March 31, 2019.

	Total	Less than 1 year	1-5 Years	More than 5 Years
		(US$ in millions)		
Short-term loans	3,671.4	3,671.4	—	—
Trade payables	3,290.1	3,290.1	—	—
Due to the Government	2,658.3	1,726.2	328.2	603.9
Accrued expenses	2,115.1	2,115.1	—	—
Other payables	1,468.5	1,468.5	—	—
Long-term liabilities	2,175.4	456.5	1,384.8	334.2
Bonds payables	20,587.6	611.4	5,888.0	14,088.1
Other non-current payables	118.1	—	78.5	39.6
Total	**36,084.6**	**13,339.2**	**7,679.6**	**15,065.8**
Operating lease commitments	1,121.8	498.8	557.7	65.3

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that we believe have or are reasonably likely to have a current or future material effect on our financial condition, change in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Inflation

According to the Central Bureau of Statistics (Badan Pusat Statistik, formerly known as Biro Pusat Statistik) Indonesia, Indonesia's annual overall inflation rate as measured by the consumer price index was approximately 3.0% in 2016, 3.6% in 2017, 3.13% in 2018 and 2.48% as at March 31, 2019. An increase in inflation may affect our cost of doing business, borrowing money and the selling prices of our products.

Market Risks

Our primary market risk exposures are to fluctuations in exchange rates, oil and gas prices and interest rates.

Foreign Exchange Risks

We conduct our business primarily in U.S. dollars, which is our functional and reporting currency. Our payments within Indonesia are conducted in Rupiah due to compliance with applicable laws in Indonesia requiring payments to be denominated in Rupiah, while most of our operating costs, particularly in relation to the procurement of crude oil and oil products, are made in U.S. dollars. As a result, we are exposed to the fluctuations of the exchange rate of the Rupiah to the U.S. dollar, particularly for cash and cash equivalents and trade receivables due from the Government and trade payables and short-term loans due to the Government and long-term liabilities. As export sales of crude oil, condensate and gas are determined and paid in U.S. dollars, while domestic sales of refined products are conducted in Rupiah, but based on market prices denominated in U.S. dollars, approximately 80% of our revenues are directly or indirectly denominated in U.S. dollars which reduces our exposure for foreign exchange risks.

A significant portion of our long-term total debt is denominated in U.S. dollars. The following table sets forth certain information regarding our U.S. dollar long-term total debt exposure for the periods indicated.

	As of December 31,			As of March 31,
	2016	2017	2018	2019
				(Unaudited)
	(US$ in millions, except percentages)			
Total U.S. dollar long-term liabilities — bank loans — net (including current portion) and bonds payables	13,180.9	12,853.4	13,320.0	13,293.1
Total U.S. dollar long-term liabilities — bank loans — net (including current portion) and bonds payables as a percentage of total long-term bank loans (including current portion) and bonds payables	96.5%	96.1%	95.8%	96.6%

We naturally mitigate foreign exchange risk through effective management of cash flows. We have entered into forward and currency option contracts that are used as a hedge for the exposure to changes in cash flows. In accordance with PBI 16/21/2014 (as defined below), our policy is to hedge a minimum of 25% of the difference between our foreign currency assets and foreign currency liabilities. See "Indonesian Regulatory Framework — Indonesian Regulation of Offshore Borrowings."

The Rupiah is a generally freely convertible currency but as a state-owned company, we are subject to Bank Indonesia requirements which restrict our ability to source U.S. dollars to three Indonesian state-owned enterprise banks, PT Bank Mandiri (Persero) Tbk, PT Bank Negara Indonesia (Persero) Tbk and PT Bank Rakyat Indonesia (Persero) Tbk.

A strengthening or weakening of the Rupiah against the U.S. dollar would have increased or decreased equity and profit or loss by the amounts shown below. This analysis is based on foreign currency exchange rate variances that were considered to be reasonably possible at the dates indicated below. The analysis assumes that all other variables, in particular interest rates, remain constant and excludes any impact on forecasted sales and purchases.

	Strengthening		Weakening	
	Equity	Profit or loss	Equity	Profit or loss
	(US$ in millions)			
March 31, 2019 (Rupiah 3% movement)	101.1	96.1	(95.2)	(90.9)
December 31, 2018 (Rupiah 3% movement)	364.0	358.9	(342.8)	(338.0)
December 31, 2017 (Rupiah 3% movement)	272.2	267.0	(256.3)	(251.5)
December 31, 2016 (Rupiah 7% movement)	869.0	866.6	(755.3)	(753.2)

Commodity Price Risks

Although we believe that the oil and gas price assumptions on which we have based our long-term development, budget projections, and reserves estimates are realistic and sustainable, we are exposed to fluctuations in prices of crude oil, natural gas, and refined products whose prices are determined by reference to international market prices which are volatile.

We purchase substantial volumes of crude oil from international suppliers in connection with our downstream operations and sell substantial volumes of refined products and petrochemicals to

domestic and international buyers. We do not currently enter into commodity derivative instruments or futures to hedge the potential price fluctuations of these products or for other purposes. Therefore, fluctuations of prices of crude oil, natural gas, refined products and petrochemicals may have a significant effect on our operating expenses other non-operating income/(expenses) and net income. However, the cost recovery provided to us under our production sharing arrangements and cooperation contracts gives us a partial natural hedge against commodity price fluctuations. We are considering hedging arrangements to manage our commodity price risks and may enter into such arrangements in the future.

See also "Risk Factors — Risks Relating to Our Company — The volatility in the prices of crude oil, natural gas and our refined products and the uncertainty of the market dynamics for oil and gas could adversely affect our business, financial condition, results of operations and prospects."

Interest Rate Risks

We are exposed to cash flows interest rate risk resulting from fluctuations in interest rates on our short-term and long-term debt, cash and cash equivalents, long-term investments and long-term liabilities with floating interest rates. In addition, we are exposed to fair value interest rate risk on our bonds payables, cash and cash equivalents, amounts due to the Government, short-term investments, long-term liabilities and other assets and liabilities with fixed interest rates. As of December 31, 2018, US$5,458.8 million, or 27.2%, of our financial assets and US$6,412.9 million, or 24.9%, of our financial liabilities carried floating interest rates, and US$4,297.7 million, or 21.4%, of our financial assets and US$12,074.5 million, or 46.8%, of our financial liabilities carried fixed interest rates. As of March 31, 2019, US$4,118.4 million, or 19.8%, of our financial assets and US$5,629.5 million, or 22.3%, of our financial liabilities carried floating interest rates, and US$7,868.2 million, or 37.8%, of our financial assets and US$12,062.4 million, or 47.8%, of our financial liabilities carried fixed interest rates. See "Liquidity and Capital Resources — Indebtedness." Borrowings issued at variable rates expose us to cash flow interest rate risk. We monitor interest rates to assess the potential impact of changes in these rates on our financial position. We do not currently engage in any hedging activities against interest rate risk.

A change of 0.3% and 0.2% in floating interest rates as of December 31, 2018 and March 31, 2019 would have increased or decreased income before tax by US$2.9 million and US$3.0 million, respectively. This analysis assumed that all other variables, in particular foreign currency rates, remain constant.

Credit Risk

We are exposed to counterparty credit risks on unpaid receivables, cash and cash equivalents and investments in debt securities. As of December 31, 2018, we had trade receivables of US$3,231.1 million, 40.2% of which was owed to us by our related parties. Our largest trade receivable balances were due from PLN and its subsidiaries, in the amount of US$381.6 million, and the Indonesian Armed Forces and Ministry of Defense, in the amount of US$318.1 million. As of March 31, 2019, we had trade receivables of US$3,724.2 million, 41.3% of which was owed to us by our related parties.

We make impairment provisions for our trade receivables in accordance with our accounting policies. Impairment provisions are made for commercial trade receivables based on receivable aging analysis at the end of each accounting period. As of December 31, 2018 and March 31, 2019, we made provisions for impairment of trade receivables from third parties of US$228.0 million and US$212.1 million, respectively, and for impairment of trade receivables from related parties of US$32.7 million and US$33.2 million, respectively. Based on our management's review of the collectability of each balance of trade receivables as of December 31, 2018 and March 31, 2019, our management was of the view that the provision for impairments of trade receivables was adequate.

We have procedures such as credit scoring, collateral requirement and regular confirmation and reconciliation, to monitor and limit exposure to credit risk on our outstanding trade receivables. Through this process, a portion of our credit sales are secured with customer collateral and/or bank guarantees. We have also implemented a credit management system that monitors customer usage of credit limits and automatically blocks credit lines beginning on the seventh day of nonpayment after a maturity date, and we impose penalties on overdue payments on a case-by-case basis.

Liquidity Risk

The amount of liquidity we require for our operations is uncertain and our operations may be adversely affected if we do not have sufficient working capital to meet our cash and operational requirements. This may occur as a result of, amongst other reasons, delays in the payment of the Government's subsidies. We use a significant amount of cash in our operations, primarily to procure commodities and raw materials. In particular, one of our principal operating costs is the acquisition of feedstock for our refineries. Due to the volatility in market prices for crude oil, natural gas and their refined products and fluctuations in exchange rates, our working capital and costs for our upstream and downstream operations tend to be uncertain.

We fund our operations principally through cash flow from operations, a significant portion of which comprises sales, subsidy payments, short-term working capital facilities (including bank overdrafts, letters of credit and revolving credits), and long-term bank loans. In accordance with the terms of the PSO mandate, we are required to submit our claim for subsidy to the Government on a monthly basis for the subsidized fuel that we distributed in the preceding month.

As of December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we had cash and cash equivalents of US$6,721.6 million, US$6,409.8 million, US$9,112.3 million and US$8,322.1 million, respectively.

We manage our liquidity risk by continuously monitoring forecast and actual cash flows and matching the maturity profiles of account receivables and payables.

Recent Accounting Pronouncements

We have not adopted the following standards that have been issued but will not become effective until January 1, 2020:

- *SFAS 71: Financial Instruments*, which revised the requirements related to the classification and measurement of financial instruments, including the expectation credit loss model for calculation of impairment of financial assets and implemented new general hedging accounting requirements. Earlier application of this SFAS is permitted.

- *Amendment of SFAS 62: Insurance Contract*, which is a consequential amendment due to the issuance of SFAS 71. The amended standard provides guidance for an entity who is issue insurance contracts, especially insurance companies, on how to implementing SFAS 71.

- *SFAS 72: Revenue from Contracts with Customers*, which sets out a comprehensive framework to determine how, when, and how much revenue can be recognized. SFAS 72 supersedes certain current revenue accounting standards, including *SFAS 23: Revenue, SFAS 34: Construction Contracts and IFAS 10: Customer Loyalty Programs*. Earlier application of this SFAS is permitted.

- *SFAS 73: Lease*, which establishes the principles of recognition, measurement, presentation, and disclosure of leases by introducing a single accounting model specifically for lessees. Lessees are required to recognize right-of-use assets and lease liabilities. Earlier application is permitted only for entities that apply SFAS 72.

- *Amendment of SFAS 15: Long-term Interest in Associates and Joint Ventures*, which requires the implementation of SFAS 71 on financial instruments at associates and joint ventures when the equity method is not applied. This includes long-term interest which substantially form net investment in associates and joint ventures. Earlier application of this amendment is permitted.

- *Amendment of SFAS 71: Financial Instruments* regarding prepayment features with negative compensation, which stipulates that financial assets with repayment acceleration features that generate negative compensation be classified as contractual cashflows that are solely derived from payments of principal and interest from outstanding principal. Earlier application of this amendment is permitted.

- *Amendment of SFAS 1: Presentation of Financial Statements and SFAS 25:* Accounting Policies, changes in accounting estimates and errors which clarifies the definition of material with the aim of harmonizing the definition used in the conceptual framework and some relevant SFASes.

We are currently evaluating and have not yet determined the effects of these accounting standards on our consolidated financial statements.

The following section contains the Wood Mackenzie Report, which was commissioned by us and prepared by our energy industry consultant, Wood Mackenzie. Other than information about Pertamina that was provided by us to Wood MacKenzie, the industry and market data in the Wood Mackenzie Report has not been independently verified by us, the Arrangers or the Dealers, and neither we, except with respect to information which we have provided, nor the Arrangers or any Dealer make any representation as to the accuracy or completeness of such data or any assumptions relied upon therein.

This section contains or refers to forward-looking statements made by Wood Mackenzie based on current expectations, including, but not limited to, information regarding energy demand, energy production, and oil and gas reserves. Forward-looking statements are subject to significant risks and uncertainties, as actual outcomes may differ materially from such forecasts.

1. Indonesia Overview

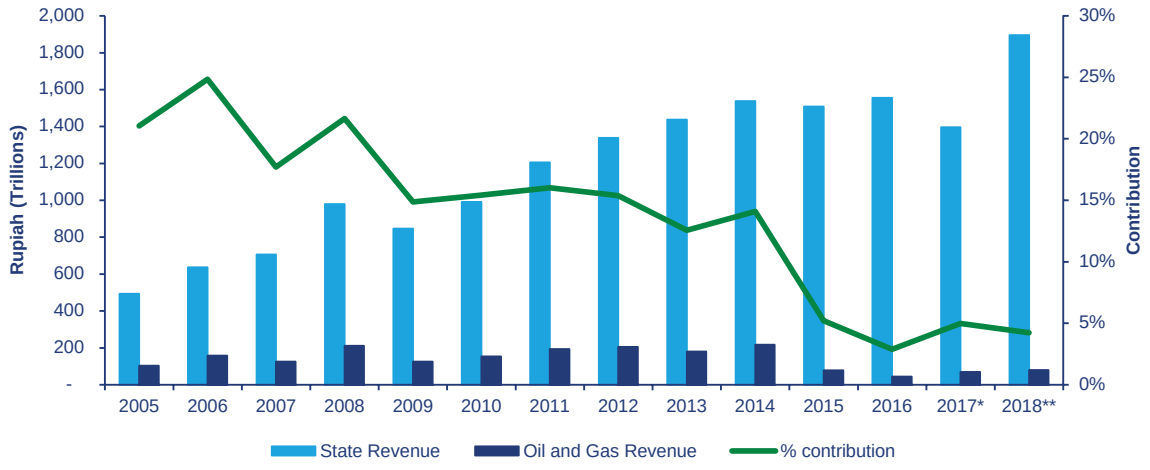
1.1. Macroeconomic overview

Indonesia is the largest economy in Southeast Asia, both in terms of domestic value-added GDP and population size. Registering real GDP growth of 5.1% in 2018, Indonesia is poised for robust long-term growth with its expanding working age population and relatively competitive cost environment for businesses.

Indonesia's long-term GDP outlook is based on Wood Mackenzie's assessment of its labour, capital stock (which is driven by investment) and productivity growth. From a labour input perspective, Indonesia will enjoy favourable demographics over the long term, as the healthy expansion of the working age population will decrease its dependency ratio and increase domestic savings. Secondly, productivity growth is another key driver of long-term GDP growth.

Therefore, Wood Mackenzie expects Indonesia's GDP to grow from US$1,146 billion (in 2010 dollars) in 2018 to US$1,449 billion by 2023, a compound annual growth rate ("CAGR") of 4.7%. Wood Mackenzie expects this to be supported by an increase of 13 million in population size from a population of 267 million in 2018. The oil and gas industry remains a relatively important factor for the Indonesian economy, contributing to 4% of the total revenue of the Government in 2018.

Figure 1 Upstream Contribution to Indonesia's State Revenue



**Note: 2017 audited data is limited to November as contribution from December has not yet been audited at the time of report publishing*

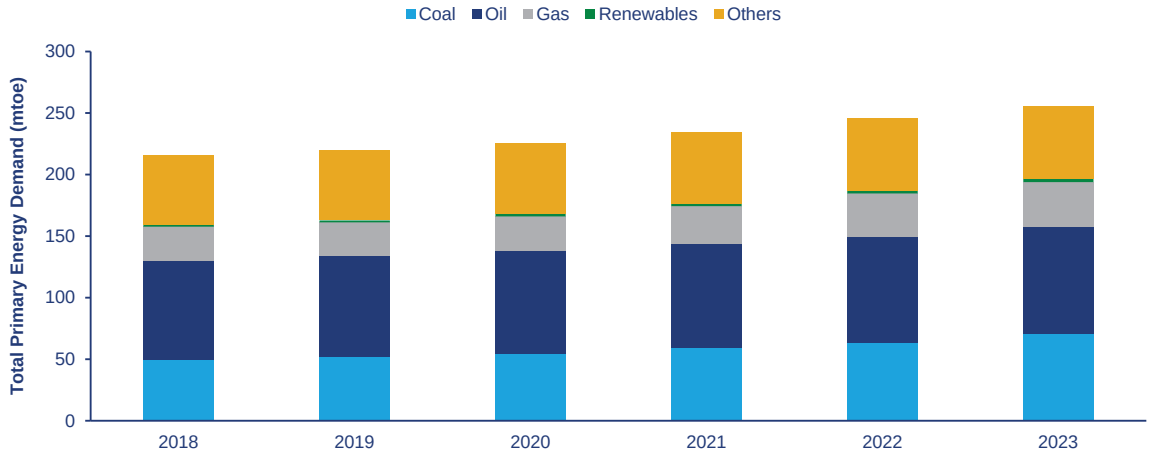
***Note: 2018 is target of state budget*

Source: PWC 2018 Indonesia Oil and Gas

Indonesia's total energy consumption is currently dominated by oil (37% of total demand in 2018) which is mainly used in the transport sector. The use of other solid fuels, which consists mainly of non-commercial biomass used for cooking in the residential, commercial and agricultural sectors, also features prominently in the current energy mix given that a large proportion of Indonesians reside in rural areas and remain unconnected to the power grid. As urbanisation continues, and the power grid connectivity improves, this is expected to reduce other solid fuel demand from 26% in 2018 to 23% by 2023.

The abundance and cost competitiveness of indigenous coal means that it will see continued and growing use in the power and industry sectors, rising from 23% in 2018 to 27% in 2023.

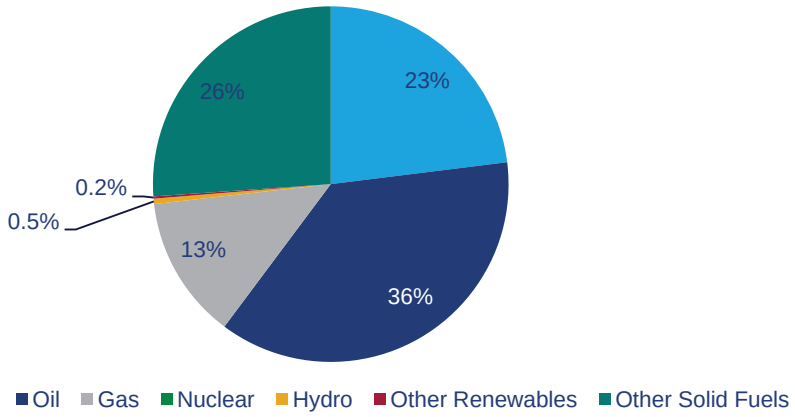
Figure 2 Indonesia Energy Consumption by Fuel



Source: Wood Mackenzie

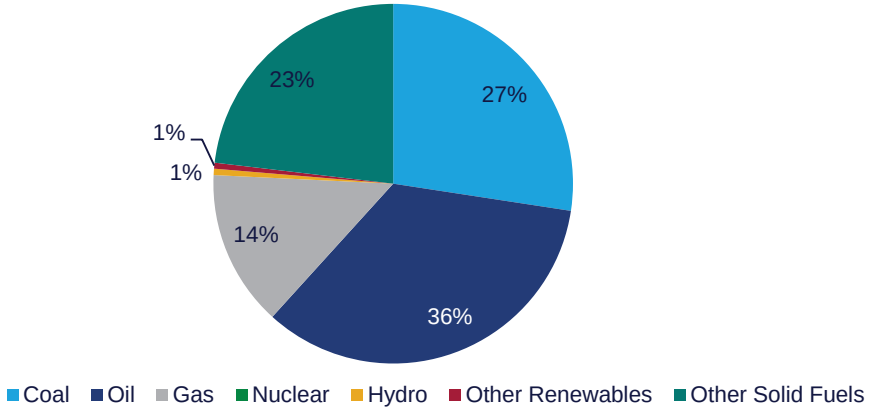
Wood Mackenzie expects Indonesia's total energy demand to increase from 215 mmtoe in 2018 to 255 mmtoe by 2023, representing a CAGR of 3.5%. While the industrial and transport sectors are expected to maintain their shares in total demand throughout the forecast period, it is the robust growth of the power sector which is expected to drive total demand.

Figure 3 Indonesia Fuel Mix 2018



Source: Wood Mackenzie

Figure 4 Indonesia Projected Fuel Mix 2023



Source: Wood Mackenzie

1.2. Regional comparison

1.2.1. Reserves

Wood Mackenzie categorises oil and gas reserves as:

Commercial reserves — These are fields which are currently in production, under development or regarded as probable developments. Fields under development are those with development plans that have been approved by the government authorities and the field participants have made the final investment decisions for the projects to proceed. Probable developments are discoveries where reserve estimates have been sufficiently proved-up and where any development plan would be economically viable. Wood Mackenzie would expect probable developments to be either on-stream or under development within a five-year timescale. As such, Wood Mackenzie regards these as commercial reserves. Using Wood Mackenzie's methodology, commercial reserves are broadly equivalent to proved and probable reserves.

Technical reserves — These are discoveries which have been made, but are not regarded as probable developments by Wood Mackenzie. This may be due to the discovery requiring further appraisal to confirm reserve estimates. In some cases the discovery may be too small and/or too expensive to be developed in order to give the participants an adequate return on their investment. Some discoveries — particularly for gas — may be stranded, with no current viable markets for any production from the discovery. Many of the technical reserves will become commercial reserves and production as and when these issues are resolved.

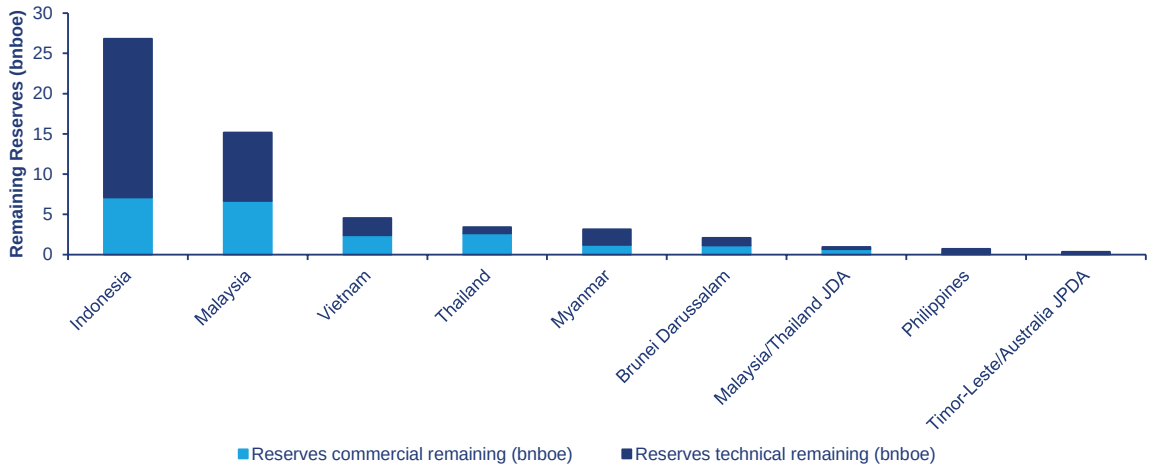
Wood Mackenzie has been publishing analyses of commercial reserves on a field-by-field basis for over 40 years in its Upstream Service. The analysis and supporting data, such as reserves, production profiles and timings, are Wood Mackenzie's own opinion. These are developed based on Wood Mackenzie's conversations with the operator of each field (and often with the non-operating partners as well). This research is supplemented by an assessment of materials in the public domain, including government estimates of reserves, and documentation released by oil companies for public relations and regulatory purposes.

Technical reserves are estimated on a discovery-by-discovery basis by Wood Mackenzie. As with the commercial fields, Wood Mackenzie discusses the size of the technical reserves in each discovery with the operator and often the non-operating partners. Where this information is confidential for a

discovery, Wood Mackenzie estimates the size of the technical reserves based on recent discoveries in the region. In addition, technical reserves may change as appraisal is carried out on a discovery. Procedures used to estimate technical reserves are less rigorous than those used for commercial reserves.

As at March 2019, Indonesia had the largest commercial oil and gas reserves in Southeast Asia with around 7.1 billion boe, 71% of which is gas (c. 28.9 tcf). Malaysia is the next largest holder of reserves with commercial reserves of around 6.7 billion boe, 75% of which is gas (c 28.6 tcf). The other countries in Southeast Asia have significantly smaller volumes of commercial reserves. Including technical resources, Indonesia also has the largest reserves and resources base in Southeast Asia, with 27.2 billion boe, of which 86% is gas.

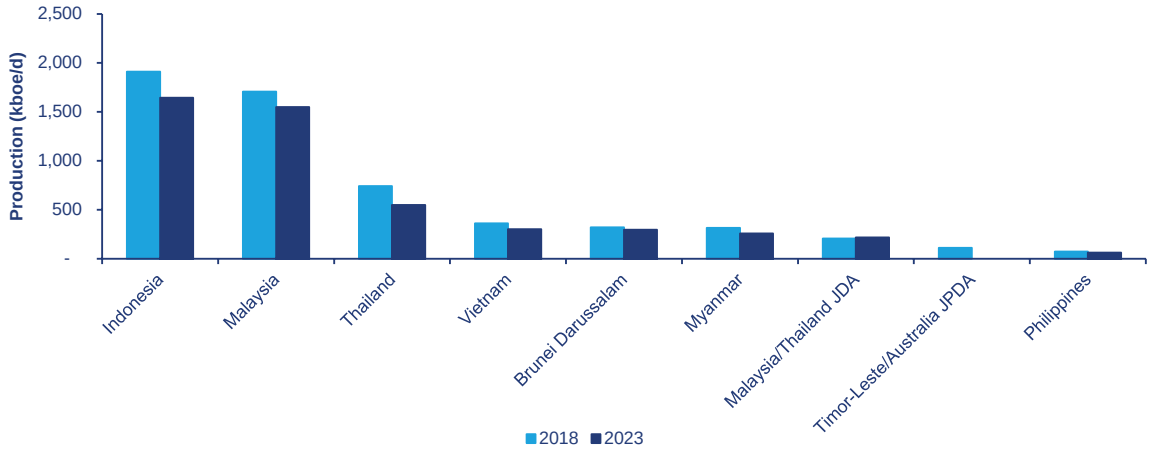
Figure 5 Regional Reserves Remaining



Source: Wood Mackenzie

1.2.2. Production

Figure 6 Regional Production



Source: Wood Mackenzie

Indonesia had the highest oil and gas production in Southeast Asia in 2018, in line with its leading regional position as the largest holder of commercial reserves. In 2018, Indonesia produced 1.9 Mboe/d

of oil and gas, of which 61% was gas. Malaysia produced around 1.7 Mboe/d with 64% being gas. The other countries in Southeast Asia had significantly lower production levels than Indonesia and Malaysia.

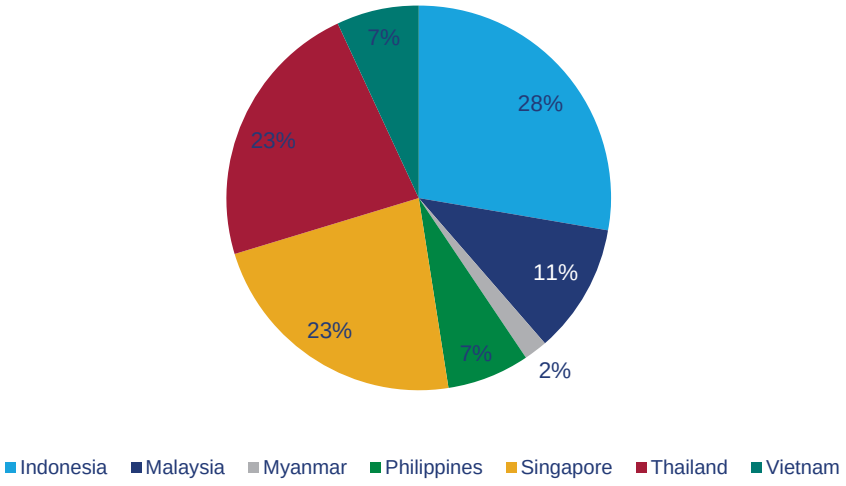
In the five-year forecast view, by 2023, production from Indonesia's existing commercial fields is expected to fall to around 1.6 Mboe/d, with gas expected to make up around 69% of total commercial production. Malaysia's commercial production is also expected to decline by 2023, to 1.6 Mboe/d, with 71% being gas.

By 2022, Wood Mackenzie expects that some of Indonesia's technical reserves would have matured into commercial developments. These future commercial fields are excluded from the 2023 production forecast, but may have a positive impact on future production levels.

1.2.3. Consumption

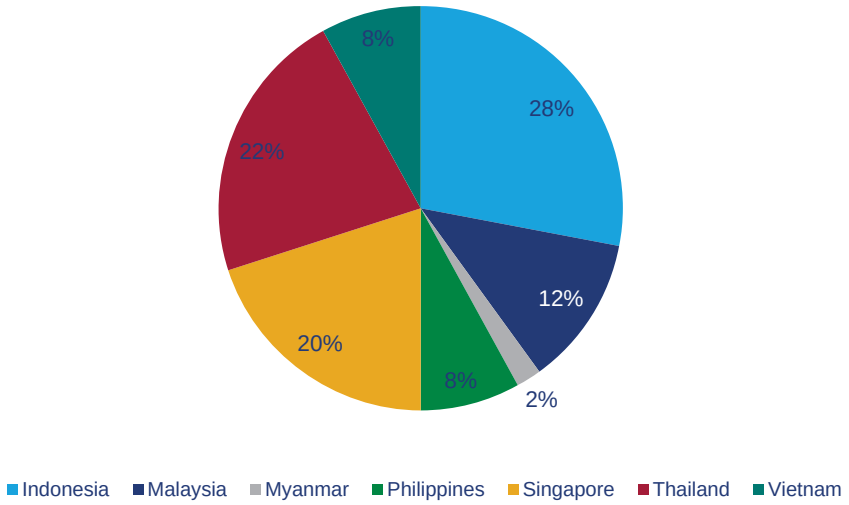
The Southeast Asian region, comprising of Singapore, Thailand, Philippines, Vietnam, Malaysia, Indonesia, and Myanmar accounts for about 18% of total Asia Pacific demand for oil products in 2018. Total demand for oil products in Southeast Asia is forecasted by Wood Mackenzie to grow from 6.4 Mb/d in 2018 to over 6.8 Mb/d by 2023; this 1.4% CAGR is close to the projected CAGR of 1.6% for the whole of Asia Pacific during the same period. Among the countries in Southeast Asia, Vietnam is expected to have the highest rate of growth in demand, with a CAGR anticipated at .6% between 2018 and 2023. Indonesia is expected to see a CAGR of 1.9%.

Figure 7 Southeast Asia Oil Demand in 2018



Source: Wood Mackenzie

Figure 8 Forecast Southeast Asia Oil Demand in 2023



Source: Wood Mackenzie

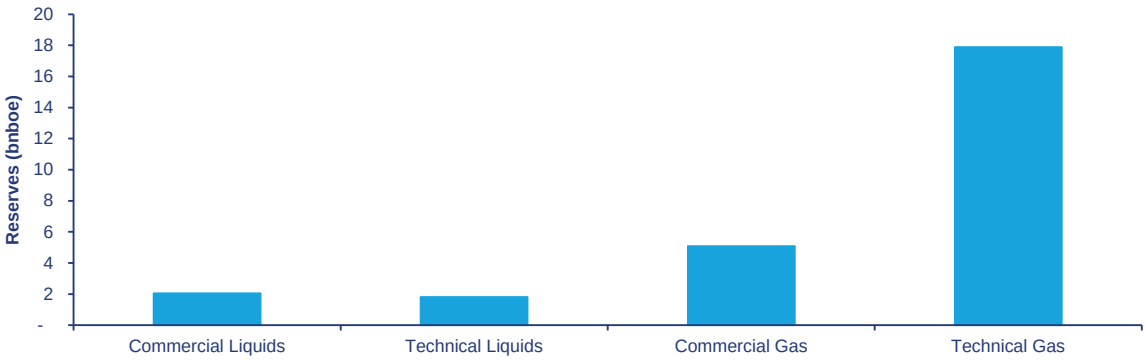
2. Indonesia Upstream Oil & Gas Overview

2.1. Oil and gas reserves

By Wood Mackenzie's estimates, Indonesia has remaining liquids reserves (both commercial and technical) of 3.8 billion barrels, of which around 2.0 billion barrels are commercial reserves and 1.8 billion barrels are technical reserves. Indonesia has remaining gas reserves & resources of 23.0 billion barrels equivalent (c 130.5 tcf), of which around 5.1 billion barrels equivalent (c. 28.9 tcf) are commercial reserves and 17.9 billion barrels equivalent (c. 101.7 tcf) are technical reserves.

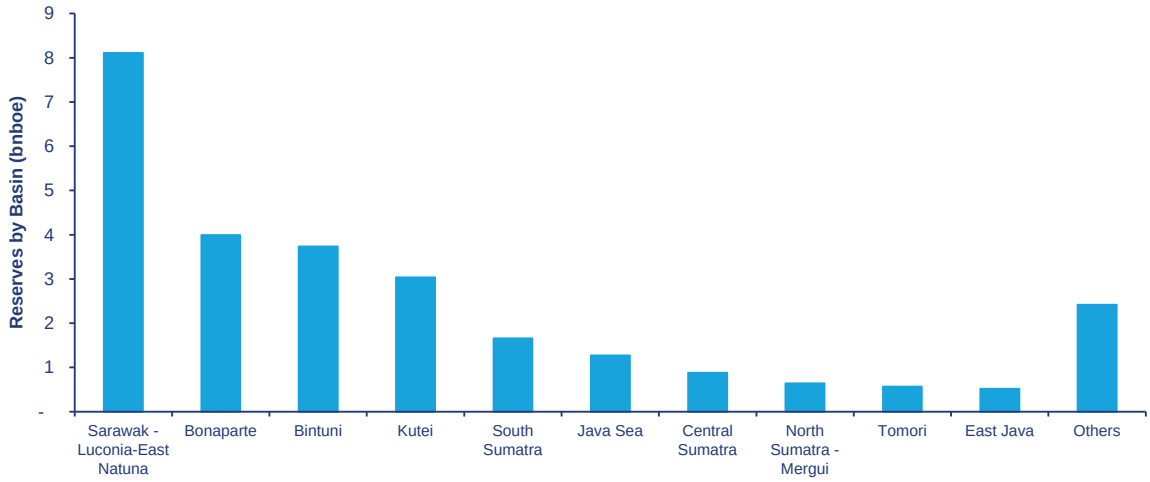
Commercial liquids reserves are concentrated in the Central Sumatra (674.4 mmboe) & Java Sea (634.1 mmboe) basins. Other basins play a smaller part in contributing to liquids reserves. By contrast, the majority of commercial gas reserves are found in the Bintuni (10.4 tcf) and Kutei (8.4 tcf) basins. In terms of technical resource, Sarawak East Natuna is the most prolific gas basin, hosting the Natuna D Alpha PSC, which has c. 46.0 tcf of currently technical gas.

Figure 9 Remaining reserves by category



Source: Wood Mackenzie

Figure 10 Remaining reserves by basin

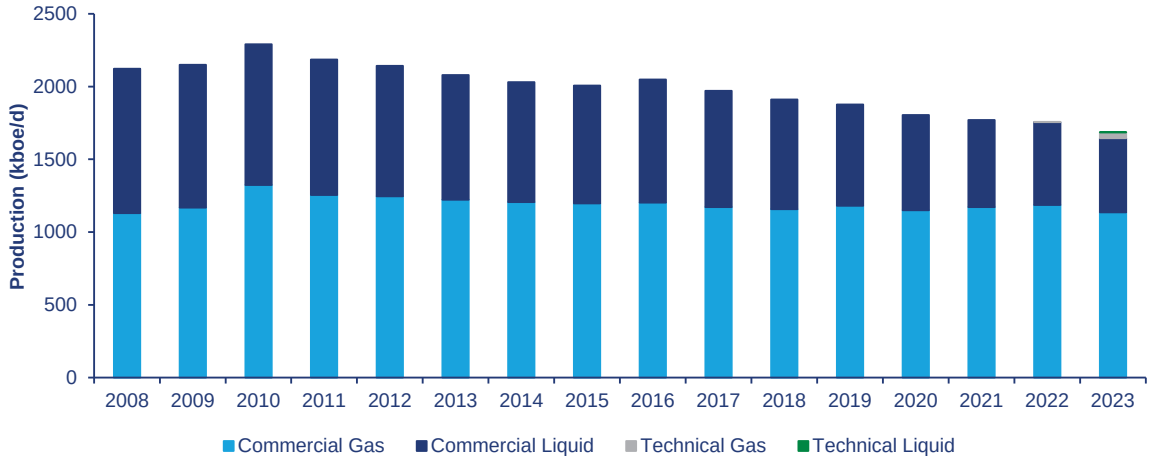


Source: Wood Mackenzie

2.2. Oil and gas production

Total oil and gas production in Indonesia in 2018 amounted to 1.9 Mboe/d (39% liquids). While liquids production declined from 992 kb/d in 2008 to 755 kb/d in 2018, gas production has increased over the same time period from 1.1 Mboe/d to 1.2 Mboe/d.

Figure 11 Indonesia Production



Source: Wood Mackenzie

Overall oil and gas production from existing commercial fields in Indonesia is in decline and will not surpass the peak production of 2.3 Mboe/d in 2010. Production from commercial fields is expected to decline to 1.8 Mboe/d by 2020 and 1.6 Mboe/d by 2023, led by a decline in liquids production from 755 kb/d in 2018 to 508 kb/d in 2023.

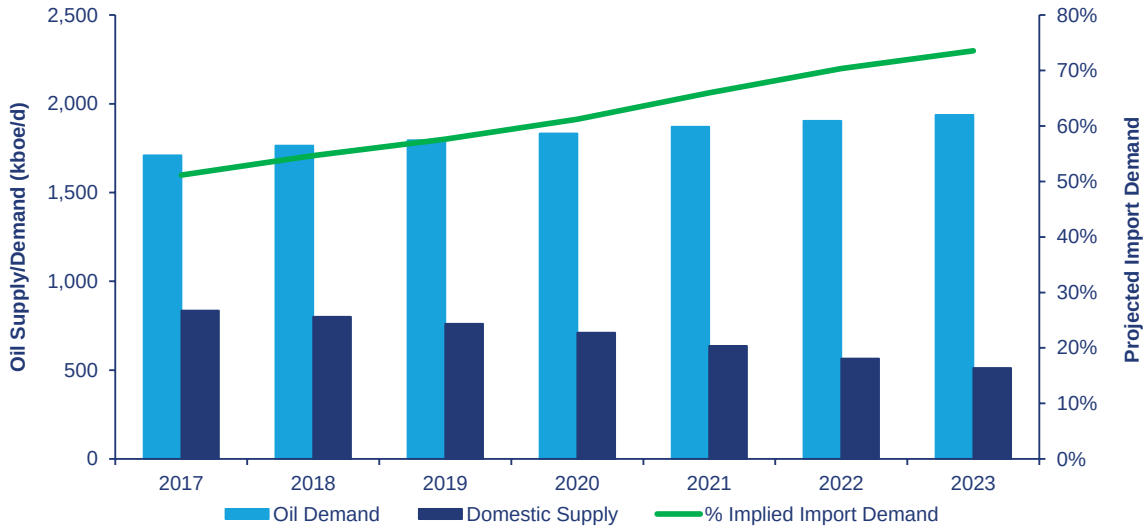
Taking into account fields currently classified as technical reserves, Wood Mackenzie forecasts that gas production will remain relatively stable (~ 1.1 Mboe/d) until 2023; technical discoveries have a limited impact on liquids production profiles due to the prevalence of gas.

2.3. Oil supply and demand balance

Indonesian oil products demand is projected to increase from 1.8 Mb/d in 2018 to 1.9 Mb/d in 2023, growing at a 5-year CAGR of 1.9%. The main driver of this demand growth is expected to be the transport sector (road, aviation and maritime), which accounted for 62% of oil demand in 2018. Industrial and RCA demand will provide a small source of demand growth (0.5% and 2.2% 2018-2023 CAGRs respectively).

With Indonesian domestic oil production in decline, the supply-demand gap is growing larger through the forecast period. Indonesia switched from being a net crude oil exporter to being a net importer around 2003. In 2018, the country was estimated to have imported over 900 kb/d (net) of oil (inclusive of all crude and refined oil products), an estimated 55% of its overall demand. Based on Wood Mackenzie's (commercial fields) supply and demand assumptions, Indonesia will be importing around 1.1 Mb/d of oil by 2020, which will constitute 61% of its oil demand requirements.

Figure 12 Indonesia Oil Supply-Demand Balance



Source: Wood Mackenzie

2.4. Gas supply and demand balance

Indonesia's gas market expanded slightly in 2018, driven by strong economic growth. This has consequently brought about a strong year for LNG demand, which grew by 0.4 Mt in 2018 to 2.8 Mt. While demand is expected to decline slightly during the 2018-2019 period underpinned by the start-ups of several coal-fired power plants, we expect the country's gas demand to increase by 0.8 bcfd from 3.3 bcfd in 2018 to 4.1 bcfd in 2023. Given declining domestic production longer term, by 2023 we expect around 33% of the country's gas demand to be met by LNG. The growing share of LNG in total gas demand offers new opportunities in both LNG procurement and regases infrastructure projects, although there are challenges unique to the Indonesian market.

Gas production is forecast to remain stable through 2019 following last year's decline in production. Indonesia's commercial gas production is expected to remain at around the 6.6 bcfd level on average until it declines in 2023. The commercial gas production includes the export and LNG projects figures. The Domestic consumption continues to surpass export, with its share of contracted gas supply increasing from 52% in 2018 to 55% over the next three years.

Regionally, supply from Central Java is expected to drop in the near to medium term outlook (2018-23) due to the Kepodang field in the Muriah block falling from 100 mmcfd in 2016 to 22 mmcfd on average between 2018 and 2023, creating a supply issue at PLN's Tambak Lorok power plants in Semarang. In South Sulawesi, the Sengkang LNG project is facing another delay as the project has yet to reach an agreement with PLN on the offtake agreement for LNG sales. Construction activities have been put on hold and we have deferred the start-up date estimate to late 2019.

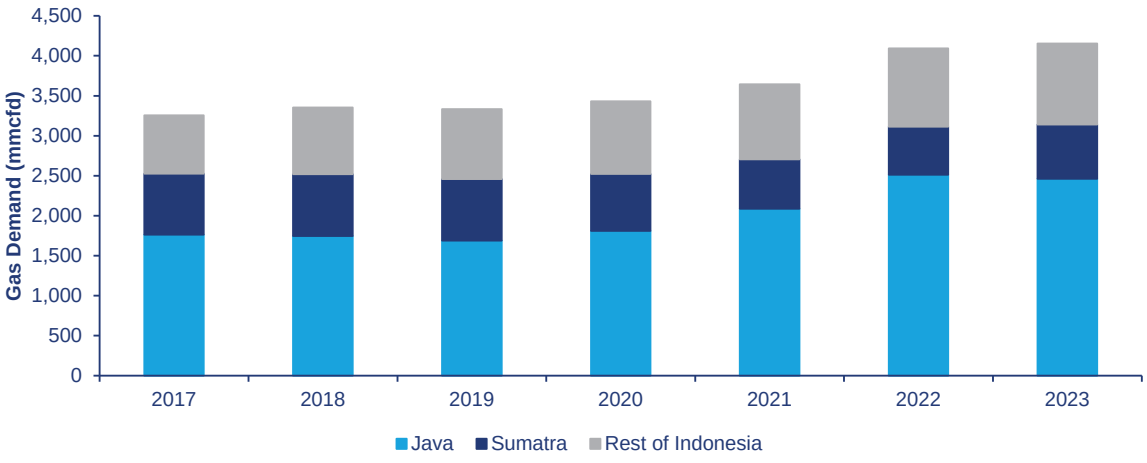
In terms of supply-demand balance, several markets will face supply constraints in the near term. West Java and North Sumatra will continue to face supply constraints due to the decline in the existing piped gas supply into the markets. West Java and North Sumatra will increasingly rely on LNG volumes to meet their gas demand, despite the recent weak trend in LNG consumption. LNG demand growth will pick up post-2025, driven by strong growth in power demand. The development of small-scale LNG projects across the country could provide additional upside to LNG demand in the longer term.

New gas reserves are needed in key producing regions. Indonesia's key gas producing regions, such as South Sumatra and East Kalimantan, are at risks of facing supply constraints unless new upstream projects progress on time and additional reserves are discovered. Both South Sumatra and East Kalimantan have been exporting gas out of their markets, but the decline in gas production and increase in local demand may threaten the sustainability of gas exports from the regions.

Recently, a confirmed gas discovery at the Sakakemang PSC onshore South Sumatra was made and preliminary assessment suggesting at least 2 tcf of recoverable dry gas, with upside potential from future appraisal. The discovery is good news for Sumatra's gas supply outlook, as it is expected to mitigate the decline by adding 24,000 boe/d of production after 2026.

In July 2019, the Government of Indonesia approved the revised Plan of Development for the Abadi LNG project. INPEX (operator, 65%) and Shell (35%) will develop Abadi via an offshore production facility and an 9.5 mmpta onshore LNG plant, at an estimated cost of US$20 billion. The revised Plan of Development also details amendments to the Masela PSC to improve the commercial viability of the project, including a 20-year extension, a further 7 years to compensate previous delays, and enhanced fiscal terms. INPEX aims to take FID within three years, and we expect first gas in 2028.

Figure 13 Indonesia Gas Demand by Region



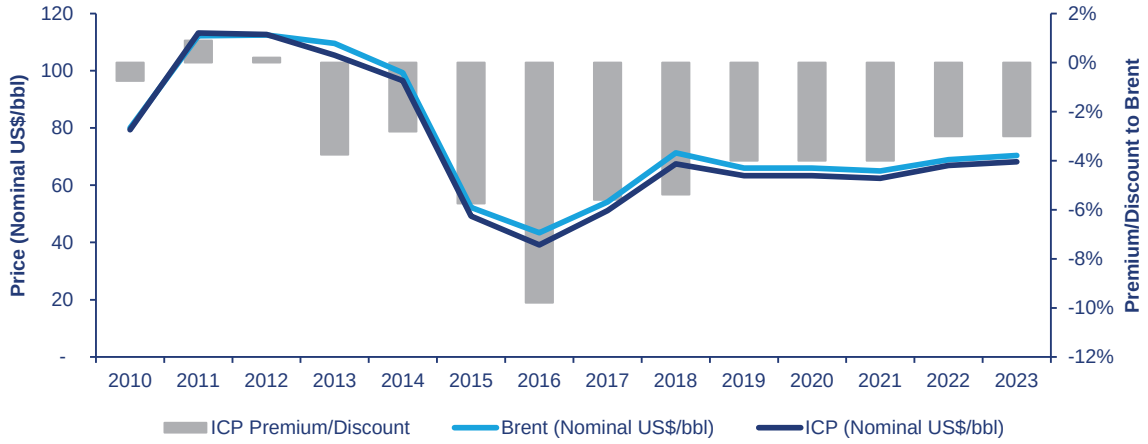
Source: Wood Mackenzie

2.5. Oil pricing

Traditionally, Indonesia has followed the OPEC line when pricing its crude for export, via an official Government Selling Price (GSP). In March 1989, the new Indonesian Crude Price (ICP) formula was introduced and was calculated as a 52-week historic average of the Asian Petroleum Price Index (APPI) for the Minas, Tapis, Dubai, Oman and Gippsland crudes.

In October 1999, the formula for calculating the ICP was changed. It was calculated as 40% of the month's average of Platts' price assessments, 40% of the month's average of RIM assessments and 20% of the month's average of the APPI assessments. This was changed again in 2007, with the weight of APPI assessments reduced to 5% and Platts and RIM increased to 47.5% each. In 2008, the Indonesian government removed APPI assessments all together, and derived ICP prices from 50% of the month's average of Platts' price assessments, and 50% of the month's average of RIM assessments. In July 2016, the ICP was switched to a dated Brent formula. As of July 2018, the ICP was further revised to a Dated Brent plus/minus an alpha, with the Banyu Urip grade being assigned a premium to Brent.

Figure 14 ICP vs Brent Pricing Assumption



Source: Wood Mackenzie

2.6. Gas pricing

In May 2016, the government released Presidential Regulation no. 40/2016 on reference gas prices for industrial buyers, followed by MEMR Regulation No. 40/2016. Under the MEMR regulation, the reference gas prices for three sectors — fertilisers, petrochemicals and steel, are set at US$6/mmbtu. Higher prices above this level are still possible at the energy minister's discretion. We view the current price measure as unsustainable in the longer term, considering that LNG will be increasingly needed by the market.

In January 2017, MEMR released regulation no 11/2017 setting 8% ICP and 11.5% ICP (Indonesian Crude Price) as price ceiling in the power sector for wellhead and non-wellhead power plants, respectively. This was revised in July 2017 under regulation no 45/2017. The new regulation raised the gas price ceiling for PLN and IPPs from 11.5% ICP to 14.5% ICP. However the reference point for LNG volumes was also changed from the port to the power plant gate, thus the new ceiling includes regasification and pipeline tariffs. The regulation also allows PLN and independent power producers (IPPs) to import LNG from the international market if they can't secure domestic LNG below 14.5% ICP at the power plant gate.

Despite the current weakness in LNG demand, gas prices in key demand centres will be increasingly influenced by LNG prices, which range from 11% to 11.5% ICP, or JCC for domestic LNG, and 11% to 13.1% JCC for the international volumes, as piped gas supply declines. These result in an ex-regas price outlook of US$ 10.4/mmbtu on average between 2017 and 2020, and US$ 10.5/mmbtu for the 2021-2025 period (including regasification costs). In the power sector, prices of oil products and domestic coal will continue to set the upper and lower boundaries.

2.7. Upstream licensing trends

Prior to 1960, there were three foreign companies operating in Indonesia under concession agreements (Caltex Pacific Indonesia, Stanvac, and Shell). In 1963, these concessions were converted to Contract of Work agreements whereby each of the contract holders became a contractor to the State. New companies who wanted to operate in Indonesia, however, were offered the then-new concept of Production Sharing Agreement. Most companies now operating in Indonesia do so under the terms of a Production Sharing Contract (PSC).

In addition to the PSC, a number of other types of contracts have been employed, which are variations on the PSC format and include Technical Assistance Contracts (TAC); Joint Operating Agreements (JOA); Enhanced Oil Recovery Contracts (EOR); and Operation Cooperation Contracts (KSO).

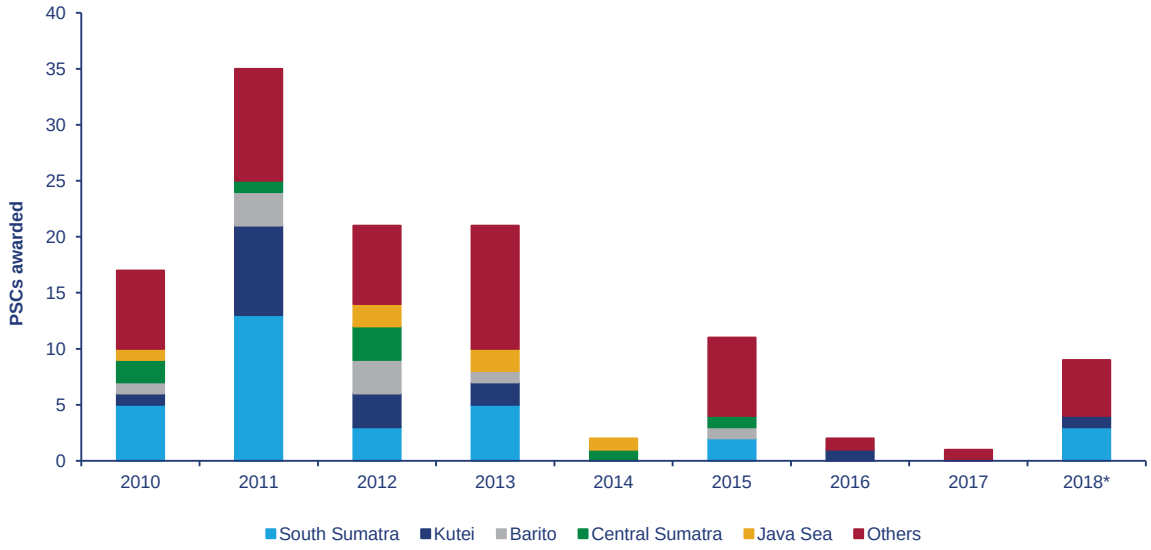
In January 2017 the MEMR introduced the Gross Split PSC terms through decree 8/2017. The Gross Split PSC removes the cost recovery mechanism, and the government and contractors split gross revenues. Upstream operations will continue to be supervised and managed by SKKMIGAS, but the new terms promise the operators a greater degree of freedom in managing the budget, costs and asset operations. The new terms are applied to future licence awards and contract extensions. Contractors may also choose to adopt the new terms for existing PSCs.

In September 2017, the MEMR enacted a new regulation (MEMR 52/2017), that revises the Gross Split PSC that was released earlier. The Contractor's base share of revenues is kept at the same level, but the revision includes improved revenue share and higher thresholds for cumulative production, the introduction of sliding scale progressive revenue share based on oil and gas prices and additional revenue share for the second and subsequent PODs on the same PSC.

The government's base share of revenues will be 57% for oil production and 52% for gas production. The contractor share of revenues can be increased, depending on field complexity. For example, a deepwater or an unconventional field will see the contractor's share of gross revenues increase by 16%. The prevailing rules of taxation are understood to apply. DMO oil will receive full market price.

The removal of the cost recovery mechanism will have to be clarified by further regulatory changes, particularly on the taxation and procurement aspects. Initial tax rules were enacted through GR 53/2017, confirming currently applicable tax rates.

Figure 15 Indonesian PSC awards by year and basin



Source: Wood Mackenzie

**Note: 2018 excludes PSC extensions from existing producing blocks*

Exploration blocks are offered via regular tender and direct offer during the annual bid rounds. The direct offer scheme allows operators to submit bids for unlicensed blocks from previous rounds, or propose open areas for license. To propose an open area for licensing, a preliminary survey and study are usually required in the form of a Joint Study with the Directorate General of Oil and Gas (MIGAS), a directorate within the Ministry of Mining and Energy (MEMR). All blocks offered are then advertised and interested companies have one month in which to submit bids. Under the second 2012 petroleum bidding round, 23 blocks were announced as on offer, with much of the acreage focused on onshore Kalimantan. Seven blocks were available under the regular tender system, and 16 blocks were available under the direct offer mechanism.

Exploration activity at the start of the decade was boosted by high interest in Indonesia's unconventional potential, with a record number of CBM licences awarded in 2011 and the first shale gas acreage awarded in 2013. However, conventional licensing activity has failed to excite, with a lack of established E&P players entering the country and low levels of frontier acreage awards.

Of the 11 blocks awarded in 2014, nine (six conventional, three unconventional) were awarded through direct offer, and two under regular tender. 24 bids were received for 14 of the 16 blocks on offer. Both Shell and Statoil have added new acreage to their deepwater positions in East Indonesia. Shell's Pulau Moa Selatan block marks its return as an operator in Indonesia after almost two decades, while Statoil's Aru Trough I block builds on existing interests in the Kai-Aru Basin. The licenses for these blocks were signed in 2015.

PETRONAS and ConocoPhillips have consolidated existing positions in offshore Java and onshore Kalimantan respectively. The North Madura II licence adjoins PETRONAS' Ketapang PSC, and ConocoPhillips, via its ownership of Petcon Resources, has added new acreage close to its acreage in Palangkaraya block.

The 2015 conventional licensing round offered six blocks under regular tender and two blocks under direct offer. The post-tax profit sharing for oil in the round ranged from 70:30 to 65:35 in favour of the government. Post-tax profit sharing for gas production will be 60:40, with the exception of Southwest Bengara at 65:35. Despite the post-tax profit split increase for investors, there were no awards made for this bid round.

The 2016 conventional licensing round was announced in July 2016, with seven blocks under regular tender and seven blocks through direct offer. Bidders were invited to bid on signature bonus and profit share splits, which have been fixed in the past. Most of the blocks offered fall within the frontier region.

The 2017 licensing round saw five out of the ten conventional blocks offered attracting bids — all through regular tender. No unconventional blocks were awarded. This was the first bid round to incorporate the Gross Split PSC terms. Five different companies were awarded acreage, all of which have existing positions in the country.

Indonesia carried out three rounds of licensing in 2018. The first round offered 24 conventional and two unconventional blocks. In August 2018, Indonesia launched the second licensing round, offering three exploration blocks and three PSC extensions. Finally, the third licensing round offered four conventional blocks through the direct proposal scheme. Overall in 2018, 9 exploration blocks were awarded.

In the first half of 2019, Indonesia completed its first bid round for the year offering two production blocks onshore Sumatra, and three exploration blocks across Natuna, Kalimantan and West Papua. Two of the five blocks were awarded to Kufpec Regional Ventures and the combined Sonoro Energy and PT Menara Global Energy; the remaining three blocks were not awarded as the bidders had not met the auction requirements. Subsequently, Indonesia has recently launched its second bid round, comprising of four blocks; West Kampar, West Ganal, Kutai and Bone blocks. Bids for the second licensing round are expected to be due by 31 July 2019.

CBM

The first Indonesian CBM licences were awarded in 2008, with seven blocks going to a mix of local and international companies. This was followed by a further 13 awards in 2009, three in 2010 and 23 in early 2011. Acreage awards to date have been focused on Kalimantan or Sumatra, involving companies of varying stature — from ExxonMobil, BP, Total, Medco Energi, Dart Energy and VICO, to small indigenous companies. However, poor initial results from test drilling have led to a number of the larger players relinquishing their interests, particularly in Kalimantan.

Shale

Plans for the award of shale gas unconventional acreage were announced in December 2012. Six blocks believed to be prospective for shale gas were announced as a part of a regular tender offer for 2013, and PERTAMINA was awarded the Sumbagut PSC in May 2013. Two further shale gas blocks were offered up in December 2013 as part of the first unconventional petroleum bidding round for 2013. The Kisaran, Palmerah and Selat Panjang unconventional PSCs were awarded in March 2015. All three blocks have underlying conventional licenses which share the same acreage.

TAC and KSO contracts

PERTAMINA regularly offers a number of areas across its own-operated acreage to contractors. These areas, which cover either discrete mature fields, or under-explored non-productive acreage, are operated under a Technical Assistance Contract (TAC). After PERTAMINA EP was formed, new areas have been offered under an Operation Cooperation (KSO) contract. It is understood that expiring TAC contracts will be transformed into KSO contracts, should they be extended.

The KSO contract is effectively a subcontract whereby PERTAMINA EP still holds the licence for the block, and the contractor conducts exploration activities or operations on an existing discovery.

There are two subdivisions of this contract type: production and exploration. The contracts last for up to 15 and 20 years respectively, but may be cancelled after set periods early in the contract. The contractor earns its fees from any incremental hydrocarbons produced above an agreed baseline.

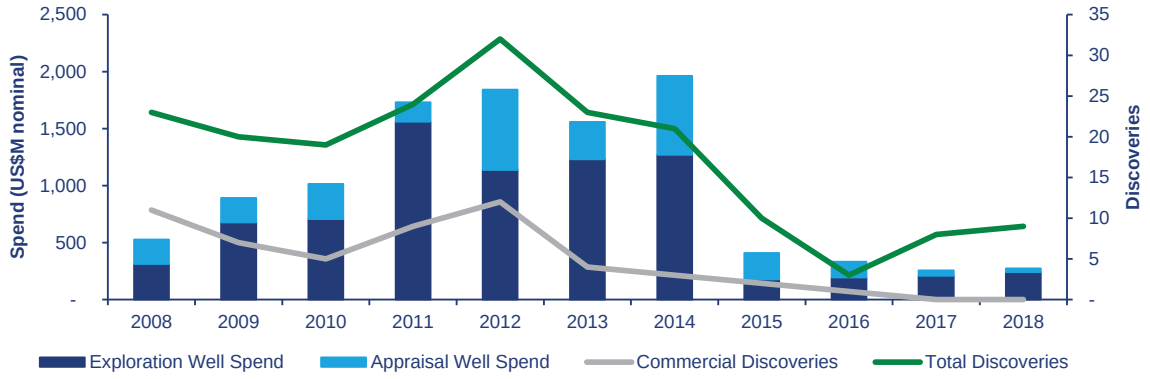
Of the 14 blocks offered in 2006, seven were for exploration acreage and seven for production areas. All awards were made to Indonesian companies. In total, 10 blocks were awarded on 24 April 2007. Three exploration blocks were awarded: Suci and Kendal in Java and Kamundan in West Java. The seven production areas were Perlak, in North Sumatra, Ibul Tenggara, Sungai Lilin and Tanjung Tiga Timur in South Sumatra, Sambidoyong in Java, Bangkudulis in northern Kalimantan, and Wiriagar (Oil) in West Java.

The contracts for operating the Sambidoyong and Wiriagar (Oil) areas, awarded to Elnusa, were later cancelled by PERTAMINA EP. A small number of KSOs are awarded on a regular basis with the most recent being the award of Trembul to GSS Energy in 2016.

2.8. Exploration spending and activity

Between 2009 and 2018, Wood Mackenzie estimates that US$10.3 billion (nominal terms) has been spent on exploration drilling in Indonesia. A further US$2.8 billion (nominal terms) is estimated to have been spent on appraisal drilling during this period. Unfortunately, wildcat exploration in Indonesia's frontier basins has initially proved disappointing, with a number of operators re-evaluating their exploration plans. Several companies including Anadarko, Marathon, Murphy and Hess, have either exited Indonesia or reduced their exposure to the countries' highly prospective but high risk frontier regions.

Figure 16 10-Year Exploration and Appraisal Spend and Discoveries



Source: Wood Mackenzie

Over the past 10 years, discoveries (both commercial and technical combined) peaked in 2012 with 32 discoveries. While Indonesia has only seen one commercial discovery that has achieved commerciality since the start of 2016.

Exploration activity in terms of wells drilled had already started to decline in Indonesia since 2012 (exploration wells dropped from 131 to 88 over 2012 to 2013). Drilling has continued to decline year on year, to a nadir of 27 wells in 2017, a figure ~20% of the 10 year peak. Drilling has continued to focus on the traditional producing basins of Sumatra, Java and East Kalimantan, but in recent years, activity has begun to test the deeper waters and underexplored basins of Eastern Indonesia.

Indonesia is viewed by many as having considerable oil and gas potential, particularly in the eastern basins, where large areas, both onshore and offshore, remain relatively unexplored. The major problem faced by potential explorers in these basins is the sheer size of the area to be explored. This, in combination with the lack of infrastructure and the harshness of the terrain, makes it difficult for oil and gas potential to be realized. For example, many of the prospective onshore areas are in remote jungle regions. The lack of infrastructure makes the logistics of petroleum exploration very difficult.

In 2019, Repsol made the Kali Berau Dalam discovery in the Sakakemang PSC block, which had an estimated 2 tcf recoverable dry gas (350 mmboe), with upside potential from future appraisal. This is one of the largest exploration discoveries in recent years, which has revived the exploration sentiments in Indonesia.

2.9. Development spending and activity

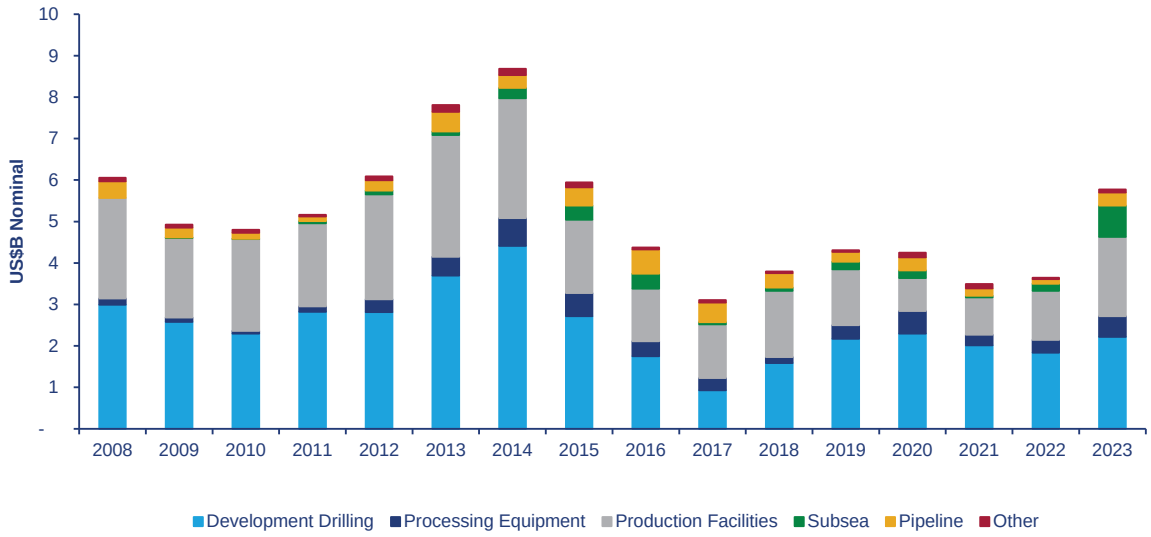
Over the last 10 years between 2009 and 2018, Wood Mackenzie estimates that US$54.7 billion (nominal terms) was spent on capital expenditure on Indonesian oil and gas fields and associated infrastructure, with a forecast five-year outlook (2019-23) of US$21.5 billion (nominal terms). The key developments during the five-year forward outlook are the post expiry Offshore Mahakam PSC and the Jambaran — Tiung Biru field within the Cepu PSC, and Tangguh Phase 2 (combined US$6.5 bn, nominal terms).

Development spend in Indonesia picked up significantly between 2010 and 2014 (from US$4.8 bn to US$8.7 bn, nominal terms). The largest contributors to this increase were the Rokan PSC area, where a continued program of infill drilling and EOR techniques (steam- and water-flood) drove higher capex, and increased development drilling activity at the Offshore Mahakam PSC.

While Rokan and Offshore Mahakam drove the increased spend from 2010-2014, declining spend on these two areas also contributed to the sharp fall in development activity in Indonesia from 2015-17 (from US$5.9bn to US$3.1 bn). Spend at other smaller contract areas and fields such as the Corridor PSC and PERTAMINA's Java fields fell, largely in response to the oil pricing environment, and were not replaced with new projects given the limited upstream sanctions over this period.

With limited near term growth opportunities in Indonesia, we do not forecast a significant growth in development expenditure out to 2023 (reaching US$5.7 bn in nominal terms). Spend is expected to be concentrated in developing incremental brownfield upside at the larger PSCs, and sustaining feedgas supply into Indonesia's LNG liquefaction facilities (e.g. field like Vorwata). We expect a notable increase in development spend beginning 2023 due to higher development spending for production facilities (e.g. in Rokan, Dara, Ganal PSC) and subsea facilities (Ganal, Masela and Rapak PSC).

Figure 17 Indonesian Development Spend

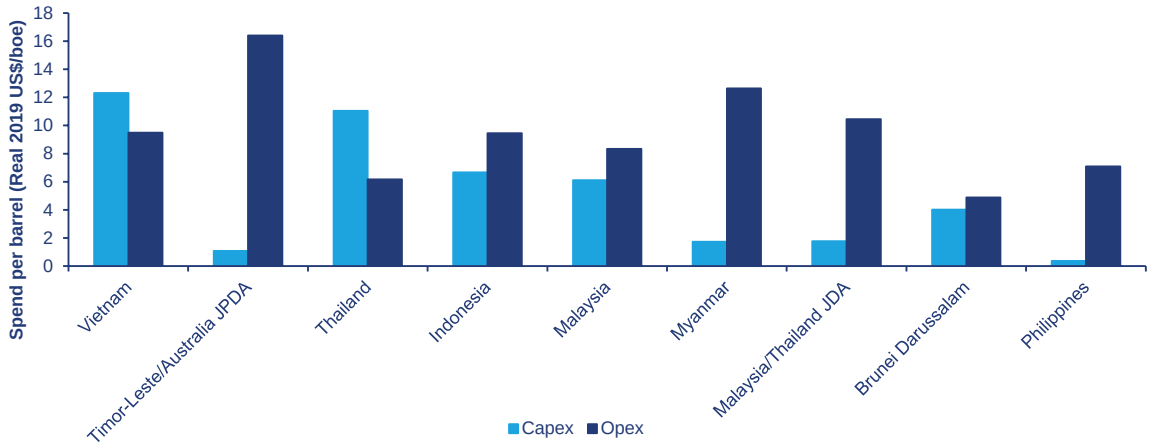


Source: Wood Mackenzie

2.10. Regional cost competitiveness

Cost competitiveness is defined here as current year (i.e. forecast full year 2019) capex and opex per barrel, in real 2019 US$ terms. Indonesia ranks as the fourth highest cost province behind Vietnam, Australia-Timor Leste JPDA and Thailand. Individually for unit capex and opex, Indonesia ranks as third and fifth highest in the region in both categories respectively.

Figure 18 Capex and opex spend per barrel by country



Source: Wood Mackenzie

2.11. Oil infrastructure

Indonesia has a total of nine active oil refineries of which six have a refining capacity of >100 kb/d. These refineries are located in East Kalimantan, Java, Sumatra and West Papua, six of which are wholly owned and operated by PERTAMINA. PERTAMINA is also understood to be major shareholder for the TPPI refinery in Indonesia.

PERTAMINA began oil refining through its first refinery at Sungai Pakning in Riau, which started operations in 1969, with a capacity of 50 kb/d. Through a series of acquisitions and capacity expansions, PERTAMINA has a current refining capacity of over 1,000 kb/d.

To reduce its reliance on imported petroleum products, Indonesia is increasing domestic product supply by increasing refining capacity through refinery expansions and construction of new grassroots refineries. An upgrade of residual cracking capacity at the Cilacap refinery was brought onstream in October 2015, and a continuous catalytic reformer upgrade along with the addition of an isomerisation unit under the Blue Sky project was completed in 4Q18.

Further upgrades and expansions are also planned for the Balikpapan, Dumai and Balongan refineries. The 5 existing refineries of Balongan, Cilacap, Dumai, Balikpapan and Musi are part of the government's Refinery Development Master Plan (RDMP) to improve their capacity and competitiveness, on the back of increasing national energy security and self-sufficiency. With the exception of Balikpapan for which we expect its expansion to be completed in mid-2021, the expansion and refurbishment of the other four refineries is expected to be completed post-2023.

Previous efforts for new grassroots refineries were set back by the subsidised domestic market, as it did not provide a sufficient rate of return. However, the Indonesian government has withdrawn subsidies in the retail sector in January 2015 with the fall in global crude oil price. This may again generate interest in new grassroots refinery projects in Indonesia. In August 2016, the Indonesian government launched a regulation enabling the development of private-owned mini-refineries, with capacities up to 20 kb/d, near upstream production facilities.

2.12. Gas infrastructure

Gas in Indonesia has historically been developed for export and accordingly most of the infrastructure investment has been in LNG facilities. There are three LNG plants in operation: Bontang in East Kalimantan, Donggi-Senoro in Sulawesi and Tangguh in West Papua. The Arun facility in North Sumatra ceased operation in 2014 and has been converted into a regasification plant.

Indonesia's first LNG was produced by the Bontang plant. The plant is owned by the Government of Indonesia. There are currently eight processing trains, with a capacity of 22.2 mmtpa. The Offshore Mahakam PSC supplies over 50% of the feedstock for the plant which has struggled with under-supply since 2005. The Arun LNG plant started production in 1978. The liquefaction plant was operated by PT Arun. At peak there were six trains onstream, with a capacity of 12.3 mmtpa. Following depletion of the fields that supplied the plant, and the expiry of the last export contracts in 2014, Arun LNG has been converted into a 1.5-mmtpa regasification facility. The plant received its first LNG cargo in February 2015 from the Tangguh LNG plant, with gas delivered to local industry via the Pertagas-operated Arun-Belawan pipeline. The regas facility is operated by PERTAMINA.

First LNG was shipped from the Tangguh LNG plant in July 2009. Gas from fields located on the Berau, Muturi and Wiriager PSCs supply two trains with a total capacity of 7.6 mmtpa. In September 2012, BP submitted plans for the construction of a third LNG train, to take total production capacity up to 11.4 mmtpa. Tangguh LNG train 3 is expected onstream in 2021, with 40% of the additional capacity expected to be allocated to the domestic market. The Donggi-Senoro LNG plant in Sulawesi shipped its first LNG cargo in August 2015. Traditionally, Indonesian LNG projects have been integrated, with the LNG plant owned by the government and operated on a non-profit basis. In these projects the government took on lending risk to effectively debt-finance the project. However, the 2-mmtpa DSLNG plant, which is supplied by gas from the PERTAMINA Sulawesi and Senoro-Toili blocks, is the first LNG facility in Indonesia where the project financing risk lies with the project consortium.

Third party access on current regasification terminals in Indonesia are expected to be limited, as PERTAMINA and PGN also act as gas aggregators. The Benoa terminal is used solely for PLN's power plant operations. A number of other regas terminals have been proposed, but have not been sanctioned.

In the meantime, small-scale LNG is proceeding in East Kalimantan. The Sambera gas power plant saw its own small-scale onshore LNG storage and regasification facility in July 2018, led by PLN and Pertagas operating on a five year Build, Operate, Transfer (BOT) scheme.

In terms of pipelines, the lack of gas interconnection infrastructure divides Indonesia into several regional markets. Java Island is separated into the West Java, Central Java and East Java markets, while Sumatra Island is segregated into the Aceh/North Sumatra and Central/South Sumatra markets. Pipeline infrastructure outside Java and Sumatra is very limited, except in the East Kalimantan region around the Bontang LNG plant.

Existing inter-regional pipeline connections include the Grissik-Duri and the Grissik-Singapore pipelines connecting South Sumatra with Central Sumatra, Batam, and Singapore, and the SSWJ I and II pipelines connecting South Sumatra with West Java. In North Sumatra, the Arun-Medan pipeline was completed in December 2014, connecting the gas markets in Aceh and Medan. Export pipelines also exist in the Natuna Sea, delivering gas to Singapore and Malaysia.

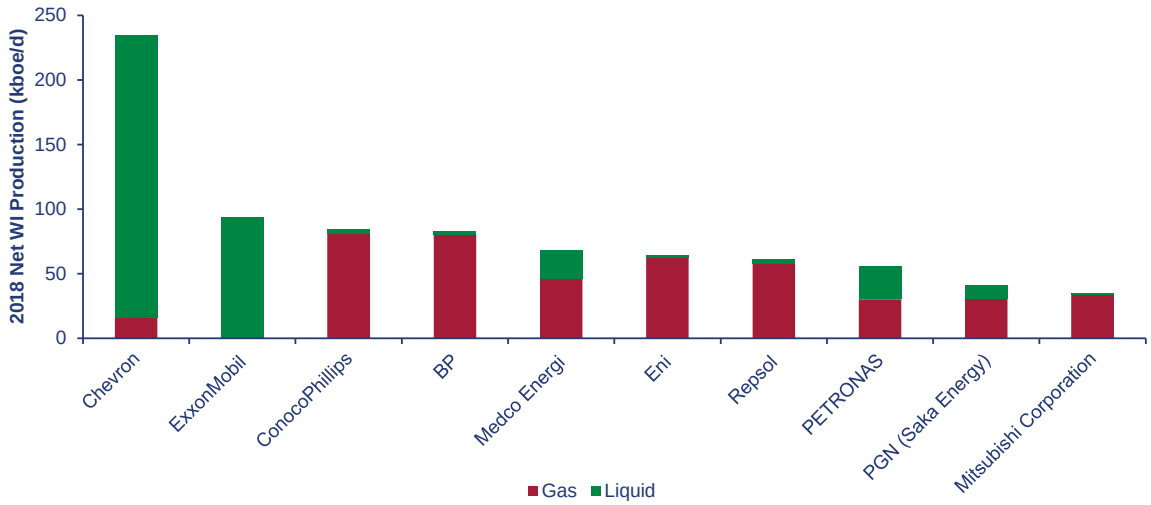
The market is growing as additional pipelines are being built. The Gundih-Tambak Lorok pipeline was commissioned in September 2014, supplying gas to Semarang. Another pipeline to Semarang from Muriah was completed in August 2015. The Cilegon-Bitung pipeline, part of PGN's gas pipeline expansion in West Java, began operating in 2015. In 2016, the Arun-Medan pipeline was extended further to Sei Mangke. Also in 2016, the spur line from Muara Karang to Muara Tawar in West Java was completed and is being extended further. In 2018, the Duri-Dumai pipeline went into operation, supplying gas from the Corridor and Bentu PSC to PERTAMINA's Dumai refinery. More pipelines will be completed in the near future, such as the Gresik-Semarang and Grissik-Palembang pipelines which are expected to be completed in 2019.

2.13. Competitive analysis

The following charts illustrate companies in Indonesia (excluding PERTAMINA) ranked by Wood Mackenzie's estimates of oil equivalent production in 2018 and block and net acreage positions as at March 2019.

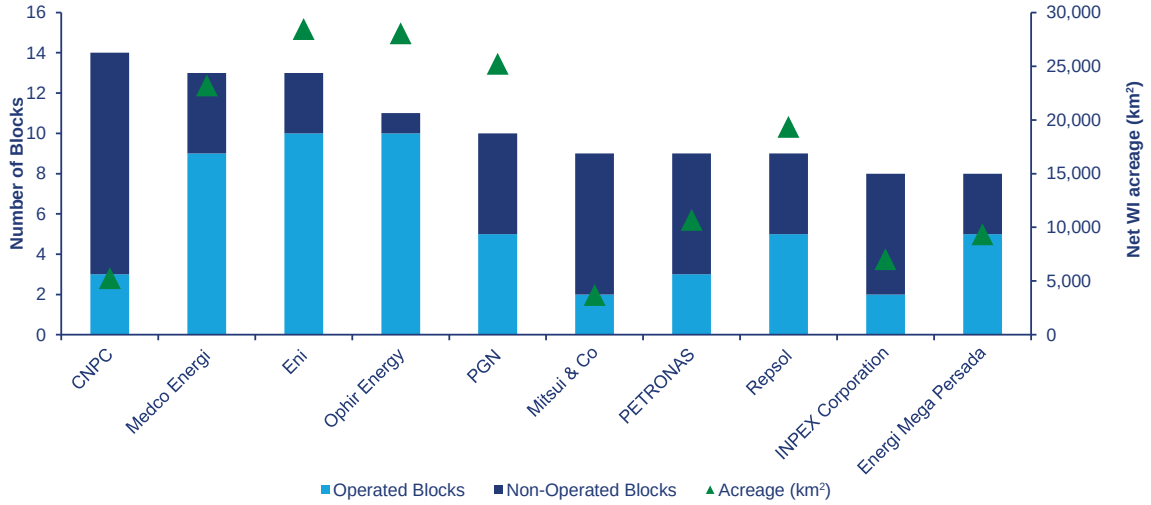
As at March 2019, PERTAMINA is the largest E&P player in Indonesia in terms of active blocks, net acreage, commercial reserve and production; PERTAMINA currently holds the most number of blocks of 90 (of which 34 are active blocks) and has the largest net acreage of 214,284 km^2 in the country. PERTAMINA also owns the largest oil and gas commercial reserve base in Indonesia. PERTAMINA is also the largest oil and gas producer with 661 kboe/d of net working interest production.

Figure 19 Top 10 (excluding PERTAMINA) E&P positions by production



Source: Wood Mackenzie

Figure 20 Top 10 (excluding PERTAMINA and private investors) E&P positions by block and acreage*



Source: Wood Mackenzie

**Note: Sugico Graha has been excluded from this analysis as they largely procure relinquished blocks from exiting companies, as opposed to other companies which competitively bid for blocks*

3. Indonesia Geothermal Industry Overview

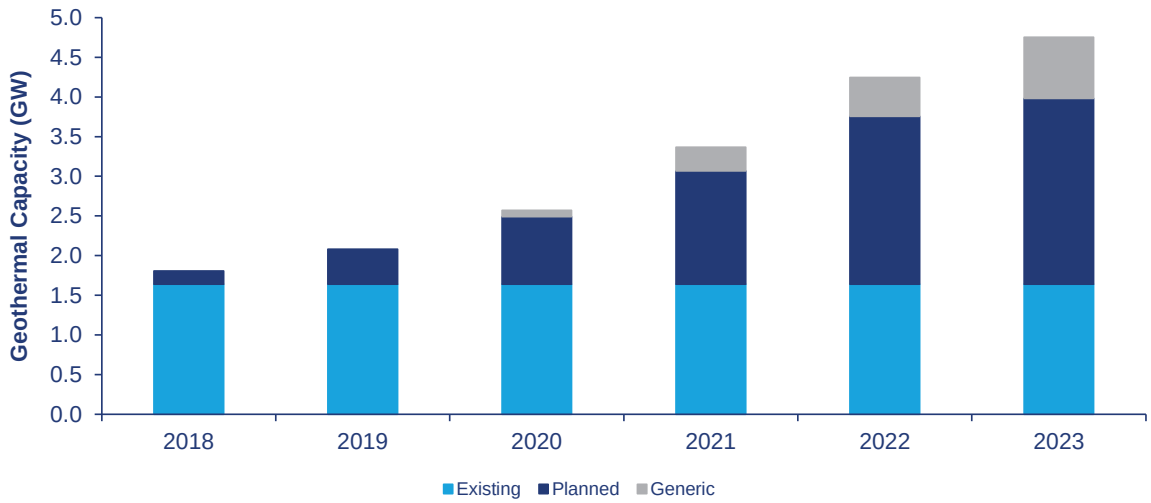
The share of renewable energy capacity in Indonesia has declined from 18% in 2005 to 15% in 2018, due to the development of large-scale coal power plants under the Crash Build I programme. We expect the share of renewable energy capacity to increase gradually, reaching 17% in 2023, as we expect more geothermal plants from the Crash Build II programme will be commissioned, together with additional hydro, biomass, solar and wind capacities.

Hydro and geothermal are the two biggest sources of renewable energy in Indonesia. In 2016, there were 4.6 GW and 1.6 GW of installed hydro and geothermal power plants, respectively. The

Crash Build II programme, introduced in 2009, includes the development of 4.8 GW of geothermal capacity. But progress has been slow, with only less than 5% capacity completed to date. We estimate Indonesia's geothermal capacity to reach 4.7 GW by 2023, out of the estimated 27 GW potential.

Geothermal is a potential abundant source of renewable energy in Indonesia. Although policies were improved in the past few years to make it more attractive to private investors, challenges in financing and connecting the plants to the main grid are still hampering development. The new geothermal law and regulation announced at the end of 2014 were expected to expedite geothermal development in Indonesia, but progress so far has been minimal.

Figure 21 Indonesia Geothermal Capacity by Status



Source: Wood Mackenzie

3.1. Geothermal Projects

The application of geothermal power started in 1982 when PERTAMINA developed the first unit of the Kamojang geothermal plant in West Java. Development of geothermal projects has gradually increased since 1997. Overall geothermal capacity increased further when Salak, Darajat, Wayang Windu, Lahendong, and Dieng generation plants came online in 2000. Since 2017, four projects have came online, adding 360 MW of capacity.

Figure 22 List of Existing Geothermal Projects

Plant	Start Date*	Retirement Date*	Available capacity	Owner	Zone
Sarulla GEO2 IPP	2018	2040	110	Medco Power	North Sumatra
Lumut Balai GEO1	2018	2040	110	PGE	South Sumatra
Karaha Bodas Geo1	2017	2040	30	PGE	West Java
Sarulla GEO1 IPP	2017	2040	110	Medco Power	North Sumatra
Kamojang GEO5	2016	2040	40	PGE	West Java
Ulubelu GEO3,4	2016	2040	110	PGE	South Sumatra
Cibumi GEO1	2015	2040	2	PLN	West Java
Patuha GEO1	2015	2040	55	Geo Dipa Energy	West Java
Ulubelu GEO2	2013	2040	55	PGE	South Sumatra
Ulumbu (APBN)	2013	2040	10	PLN	East Nusa Tenggara
Ulubelu GEO1	2012	2040	55	PGE	South Sumatra
Lahendong 4	2012	2040	20	PLN	North Sulawesi
Mataloko	2012	2040	2	PLN	East Nusa Tenggara
Wayang Windu GEO2	2009	2040	117	Star Energy	West Java
Lahendong 3	2009	2040	20	PLN	North Sulawesi
Kamojang GEO4	2008	2040	60	PGE	West Java
Sibayak GEO1 IPP	2008	2040	12	PGE	North Sumatra
Drajat GEO3 IPP	2007	2040	110	Chevron Geothermal	West Java
Drajat GEO1	2004	2040	55	Chevron Geothermal	West Java
Drajat GEO2 IPP	2000	2040	95	Chevron Geothermal	West Java
Kamojang GEO1	2000	2040	30	IP	West Java
Kamojang GEO2	2000	2040	55	IP	West Java
Kamojang GEO3	2000	2040	55	IP	West Java
Salak GEO1,2,3	2000	2040	165	Chevron Geothermal	West Java
Salak GEO4 IPP	2000	2040	197	Chevron Geothermal	West Java
Wayang Windu GEO1	2000	2040	110	Star Energy	West Java
Dieng GEO1 IPP	2000	2040	31	Geo Dipa Energy	Central Java
Lahendong 1,2	2000	2040	40	PLN	North Sulawesi

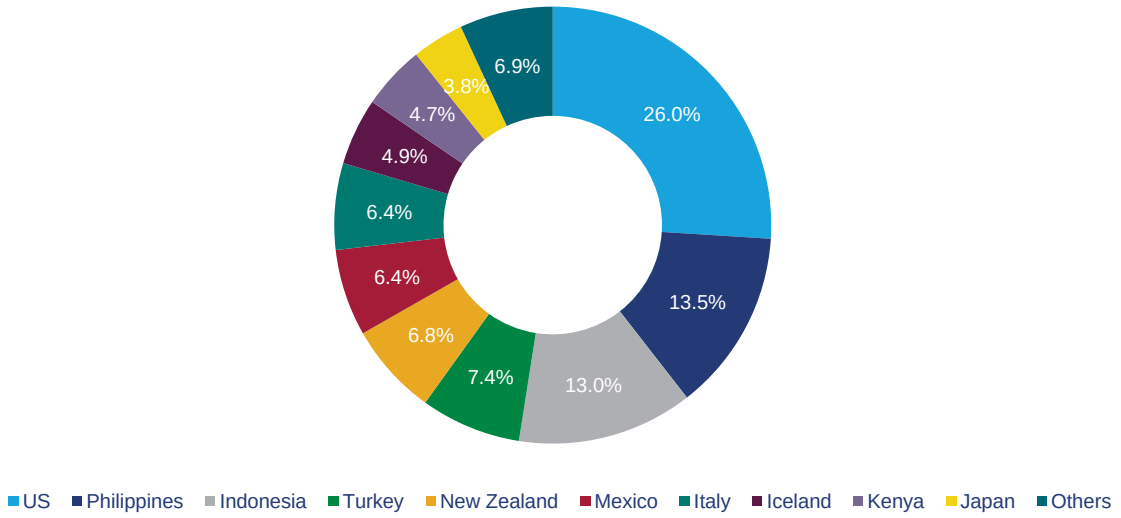
Source: Wood Mackenzie

PT PERTAMINA Geothermal Energy is the main player in the geothermal industry in Indonesia. The other players include Geo Dipa Energi, Chevron, Star Energy, Supreme Energy, Bumigas Energi and Medco Energi. Up till 2011, PERTAMINA was involved in all existing geothermal plants in Indonesia either through its own operations or joint operations with other partners. However, PERTAMINA transferred its ownership in Geo Dipa Energi to the Government in 2011. With this transfer, GDE is expected to be a competitor to PERTAMINA for the allocation of geothermal working areas and projects in future. GDE currently operates the Dieng and Patuha power plants.

On 18 February 2017, the price reference for electricity from renewable energy was reduced, as stipulated in MEMR Regulation no 12/2017. The regulation marks a shift in the government's approach towards renewable energy, as it seeks to balance the aspiration for renewable energy development with the need to maintain electricity prices at an affordable level. The previous feed-in tariffs have been reduced and capped to between 85% and 100% of the average generation cost of each region.

The new ceiling prices range from US$59/MWh (in Java) to US$144/MWh (in East Nusa Tenggara). These apply indiscriminately to all renewable energy projects, and are significantly lower compared with the previous feed-in tariffs (such as US$145-250/MWh for solar PV and US$126-296/MWh for geothermal). It could potentially shift renewable development away from key demand centres to frontier regions with higher costs of generation, and may not work without additional government support such as tax breaks, investment credits and local content relaxation. Currently, the local content requirement for solar PV for instance, is around 44%, which hinders larger players with access to cheap manufacturing facilities to participate in the sector.

Figure 23 2017 Share of Geothermal Capacity by Country



Source: BP World Energy Statistics Review 2018

4. Downstream Industry Overview

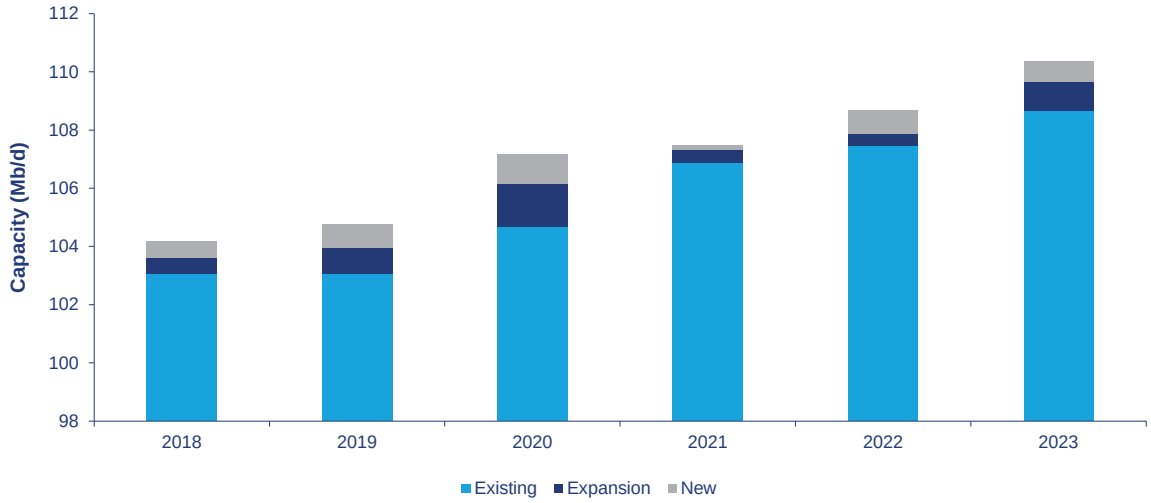
4.1. Global and regional capacity

Refiners have enjoyed a positive margin environment since 2015. Global demand growth has been consistently strong since the oil price collapse of 2014 and net refinery capacity additions have lagged behind, steadily tightening product markets. But over the next couple of years we see capacity and non-refinery supply growth running ahead of demand growth, leading to a slight softening of margins.

The IMO bunker fuel quality changes create considerable uncertainty around the outlook for 2020. We expect the change to be positive for refiners, with an extra 1.5 million b/d of demand created for gasoil in 2020. High margins will be required to ensure that demand is met. But not all refiners will benefit equally, with those generating high yields of high sulphur fuel oil, and being gasoline oriented seeing little uplift. The widening of the gasoil to fuel oil spread will also impact crude markets, sending light/heavy differentials much wider and providing a relative price boost to very low sulphur crudes.

Beyond 2020 demand growth slows due to efficiency gains and electrification of the global vehicle fleet. At the same time, we are expecting a surge in refining capacity, with 7 new refineries and many expansions adding 3.5 million b/d to global refining capacity from 2018 to 2020. Between 2020 till 2023, we expect capacity addition slow down to about 2.5 million b/d in total. In addition 3.7 million b/d of oil products are forecast to be supplied from non-refinery sources — mainly NGLs, but also biofuels, and coal-to-liquids in China. With only 6.4 million b/d of demand growth over the same period, the refining industry is expected to exert some downward pressure on utilisation and margins from 2021. The sustained period of lower margins is expected to put smaller, less complex refiners, subject to market competition, under closure pressure.

Figure 24 Planned Global CDU Capacity Additions



Source: Wood Mackenzie

There were 258 refineries in Asia Pacific, with a total refining capacity of around 35.9 million b/d by the end of 2018. China accounts for about 46% of the region's refining capacity, followed by India and Japan. The latest refinery addition in Asia Pacific was the Nghi Son refinery in Vietnam which started up in 2018.

Refinery capacity had been growing fast in Asia Pacific in response to increasing oil product demand, but is expected to slow down as a result of a slower pace of capacity addition in China and in response to a slower pace of oil demand growth in the region. We anticipate a net addition of 3.6 million b/d of refining capacity in Asia Pacific from 2019 to 2025. New grassroots refineries, nine in total, account for about 2.6 million b/d of this capacity increase. China will add seven grassroots refineries. The main projects include — Sinopec's Zhanjiang refinery in 2020 and Caojing refinery in 2023, PetroChina's Jieyang refinery in 2024, Hengli and Rongshen's large refinery and petrochemical integrated plants in 2020 and Risun Petrochemical's refinery in 2025. There is a RAPID refinery in Malaysia and Hengyi's refinery in Brunei starting up in 2019 and 2021 respectively.

In addition to the new refineries, many refineries are expanding, or adding downstream upgrading units. As some of these investments focus on residue upgrading, the distillate yields are expected to increase at the expense of residual fuel oil.

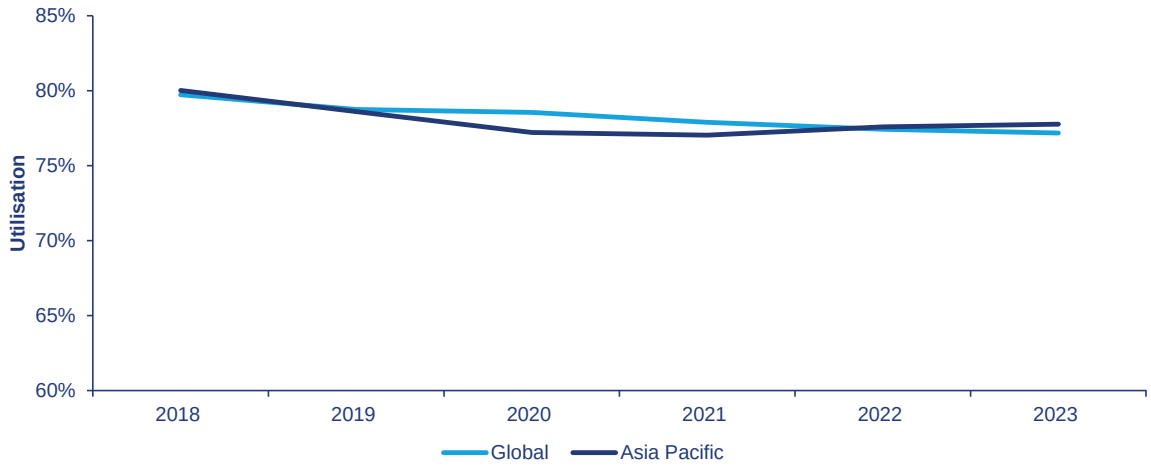
4.2. Global and regional utilisation rates

Global refinery utilisation rates were relatively low in the 1980s reflecting the high levels of spare capacity. As the industry rationalised and demand continued to grow, utilisation rates gradually increased. The increase was most pronounced in the U.S. where oil product deficits began to develop in the second half of the 1980s. Strong gasoline demand growth was satisfied through imports and refinery utilisation rates remained high. Strong demand growth in Asia fuelled by the economic boom also led to a strong refining market and higher utilisation rates. This stimulated a wave of capacity additions which coincided with a period of weaker demand immediately after the Asian financial crisis of 1997. This led to a temporary oversupply situation and hence lower utilisation rates. In Europe, persistent overcapacity combined with sluggish demand growth has led to low utilization rates for an extended period.

Utilisation rates were higher globally from 2004 onwards. Refineries were operated at rates close to maximum sustainable rates in many regions. However, constraints in the refining market were not

caused by a lack of crude distillation capacity per se but by a number of factors in the market including more stringent quality specifications, hurricane related outages in the U.S. Gulf Coast and high market demand for middle distillates such as jet fuel and diesel. These factors resulted in bottlenecks in the overall system.

Figure 25 Global and Regional Refinery Utilisation Rates



Source: Wood Mackenzie

Beyond 2020, we project demand growth to slow due to efficiency gains and electrification of the global vehicle fleet. At the same time, the refinery oversupply will result in a gradual decline in refining margins and average asset utilisation from 2019. A sustained period of lower margins is expected to put smaller, less complex refiners, subject to market competition, under closure pressure. We project the average global refinery utilisation rate to fall from 79.6% in 2018 to 77.0% by 2023, reaching a similar level to the average seen between 2009 and 2014, which prompted close to 4.0 million b/d of refinery capacity closures in Europe, North East Americas and OECD Asia.

Once again it is those regions where we expect to see refinery closures and capacity reductions in response to a sustained period of low margins. All three regions are set to see declining domestic demand, have limited, or no access to advantaged feedstocks and energy sources, and have a number of relatively small scale, older assets which will struggle to compete with new and upgraded refineries in other regions. The cut in global utilisation is equivalent to around 2.5 million b/d of refining capacity.

Asia's overall utilisation is expected to decline between 2019-2020, due to the commissioning of greenfield refineries in Malaysia, China and Brunei. Post 2022, Asia is expected to see slightly higher than global average utilisation; we expect the average Asian refinery utilisation rate in the long-term to be around 78%. The pace of refinery capacity addition at 525,000 b/d per annum from 2019 to 2025 will lag behind the demand growth of 565,000 b/d during the same period.

Natural gas liquids (NGLs) arising from oil and gas production are the main source of non-refinery supply in Asia, although supply of LPG and naphtha from NGLs is very small compared with the large deficits seen in the region. Many countries are actively pursuing biofuel policies. However, biofuel volumes are low so have very little impact on product balances for the region.

Post 2025, the total global demand growth is expected to average less than 500 kb/d per year. For the main refined products, the growth rate is even lower, averaging less than 300 kb/d per year. A major factor behind the slowing rate of growth is the increased efficiency of new cars. We expect EV's

to start to take a more significant bite out of oil demand growth towards the end of the next decade, as declines in battery costs enable them to compete in the mass-market. The implication is that the world needs the equivalent of less than one new world scale refinery every year to meet demand growth.

We forecast total product demand in Asia Pacific to grow by more than 5 million b/d, from nearly 35 million b/d in 2018 to over 37 million b/d in 2023. This translates to an average annual growth rate of 1.6% over the forecast period. In China, India and other developing economies, oil demand growth is driven primarily by the expansion of the middle class, which means there is a strong correlation of demand to GDP growth. By contrast, Japan, South Korea and other advanced economies — will see a further decoupling between oil demand and economic growth.

China and India combined are forecast to account for more than 80%, or over 2.4 million b/d, of the demand growth in Asia Pacific. Demand from the Southeast Asian developing economies is forecast to increase by 0.4 million b/d between 2018 and 2023. Offsetting partially the growth from emerging economies, oil demand in the region's advanced economies (i.e., Taiwan and Singapore in addition to the OECD Pacific countries) is forecast to decline by over 1 million b/d during the forecast period.

Transport fuel demand will be the main driver of oil demand growth, accounting for nearly two thirds of overall demand increase in Asia Pacific. This will take place primarily in the road sector, where oil demand is projected to increase by over 1.7 million b/d by 2023. Aviation will also expand, with jet fuel demand forecast to grow by nearly 3% a year. Meanwhile, the region's marine bunker oil demand is expected to reach a peak at around 2025, as demand is increasingly replaced with LNG, before returning to the 2018 levels.

The petrochemicals sector will also be a significant contributor to regional oil demand. Driven primarily by the expansion of steam cracker capacities, feedstock use of oil is expected to grow nearly 1.2 million b/d, or at the rate of over 3.9% a year, during the forecast period.

Meanwhile, competition from non-oil energy sources will have the strongest impact on demand in the industrial and power generation sectors. Demand in these sectors is expected to see a sizable decline over the forecast period although the pace of demand fall will diminish over time. To a lesser extent, residential and commercial oil demand will also be affected by competition from other energy sources such as natural gas and electricity.

4.3. Global and regional refining margins

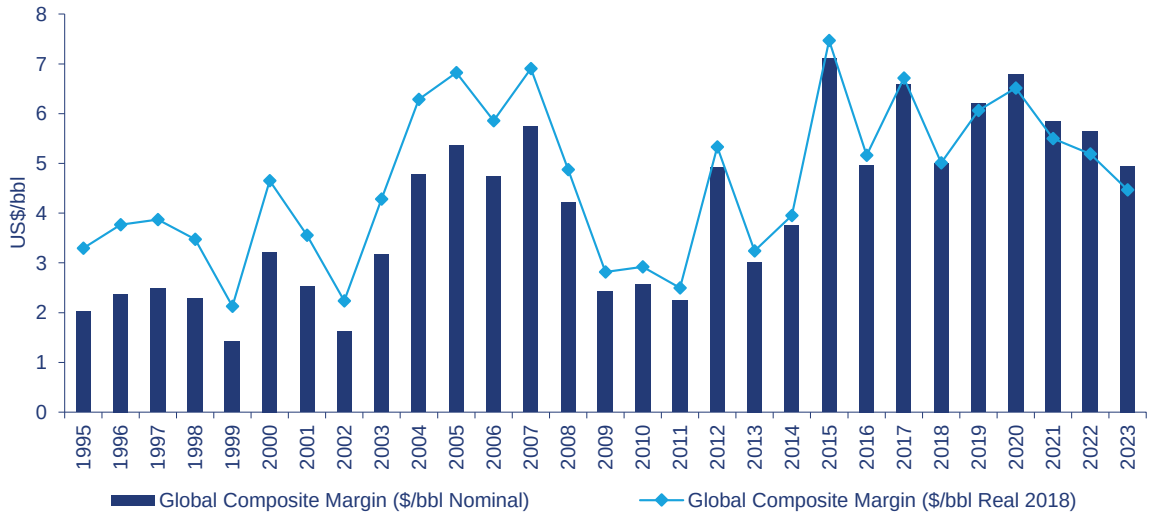
Global Refining Margins

Refinery margins were disappointing in 2018 as higher crude prices limited product demand growth. Gasoline crack spreads weakened as refiners concentrated on producing more lucrative middle distillates. Fuel oil supply was tight as the crude slate lightened and upgrading investments reduced supply. Margins are expected to struggle again in 2019 due to a large increase in refining capacity; however, the transition to IMO 2020 provides some support.

We expect a big shift to take place in 2020 when global bunker fuel specifications change. This should result in a switch in demand from high sulphur fuel oil to distillate for shipping fuels. This should result in strong margins in 2020 to provide an incentive for refiners to produce sufficient distillate. As the market adjusts to the new regulations and more ships fit scrubbers, we expect margins to ease off.

The problem of surplus spare capacity returns around 2025 as we forecast global demand to slow and demand to decline in some of the mature markets. Assuming refinery closures do take place, margins are expected to recover in the long term, thereby stimulating new investments in capacity additions in Asia and the Middle East where oil demand has some continued growth.

Figure 26 Global Composite Refining Margins*



Source: Wood Mackenzie

**Note: Global composite margin = [(50% x NWE FCC Brent + 50% x NWE FCC Urals) + (50% x USGC FCC LLS + 50% x USGC FCCMars) + (30% x Singapore FCC Tapis + 70% x Singapore FCC Dubai)] / 3*

Asia Refining Margins

Dubai FCC/hydrocracking margins weakened slightly in 2018 as weak gasoline crack spreads outweighed gains for middle distillates. Margins are forecast to strengthen in 2019 in anticipation of stronger gasoil demand in 2020.

The bunker fuel specification change in 2020 has a large impact on margins. Without the change, margins would weaken through to 2023 as European demand contracts while global distillation capacity grows more quickly than demand. This would create the need to close excess refinery capacity in Europe. However the need to produce extra gasoil to meet shipping fuel demand in 2020 provides a 'stay of execution' for European refiners with the low point for margins pushed back to 2025.

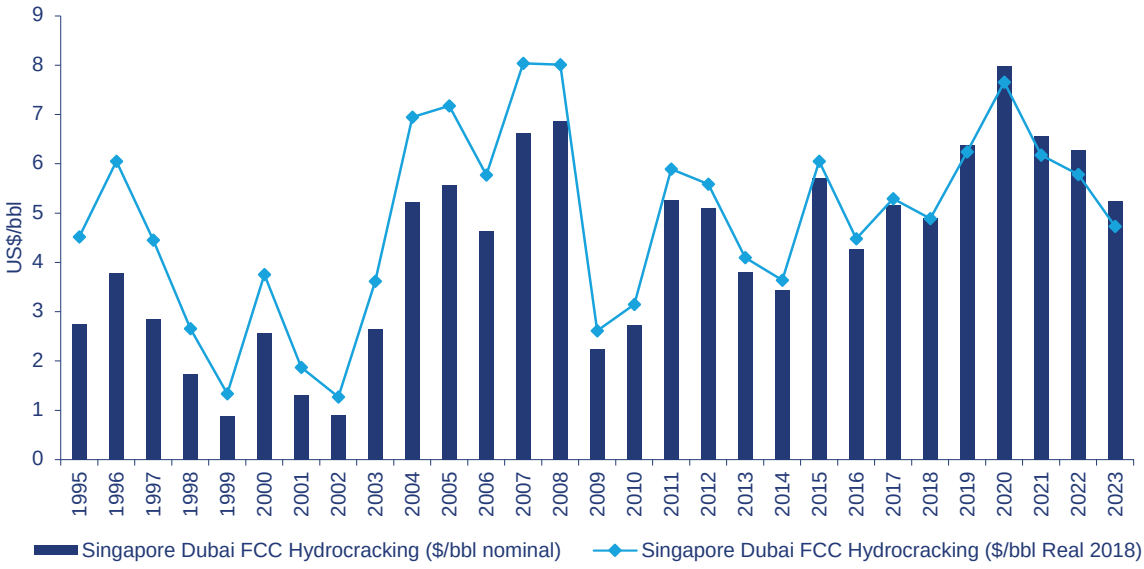
The implementation of Marpol Annex VI in 2020 will require refiners to meet the increased demand for 0.5%S bunker fuels. Our modelling shows that there will not be enough very low sulphur residual fuel oil available to meet this requirement so shippers will need to purchase more marine gasoil. This will require higher global refinery utilisation rates prompted by higher margins.

We have a spike in margins in 2020 as supply shortfalls could arise as the market struggles to adjust to the new regulations. From 2021 margins start to decline as the market adapts better and more scrubbers are fitted on board ships, allowing them to burn HSFO again.

A period of weak margins leading to refinery closures should result in a recovery in Asian margins beyond 2025. Margins are forecast to increase strongly due to the high level of demand growth in the region. We believe this steep increase is needed to provide an economic incentive for refinery investments.

There are some countries that will have a growing deficit of gasoline and investments may be made for security of supply or strategic reasons rather than based on profitable economics. Our models show that an investment in a hydrocracking/coking refinery with a high yield of diesel would provide a better economic return reflecting in the strong margins we forecast post 2030. Many new projects will have petrochemical integration, providing a better overall margin.

Figure 27 Dubai FCC/Hydrocracking Gross Refining Margins Forecast

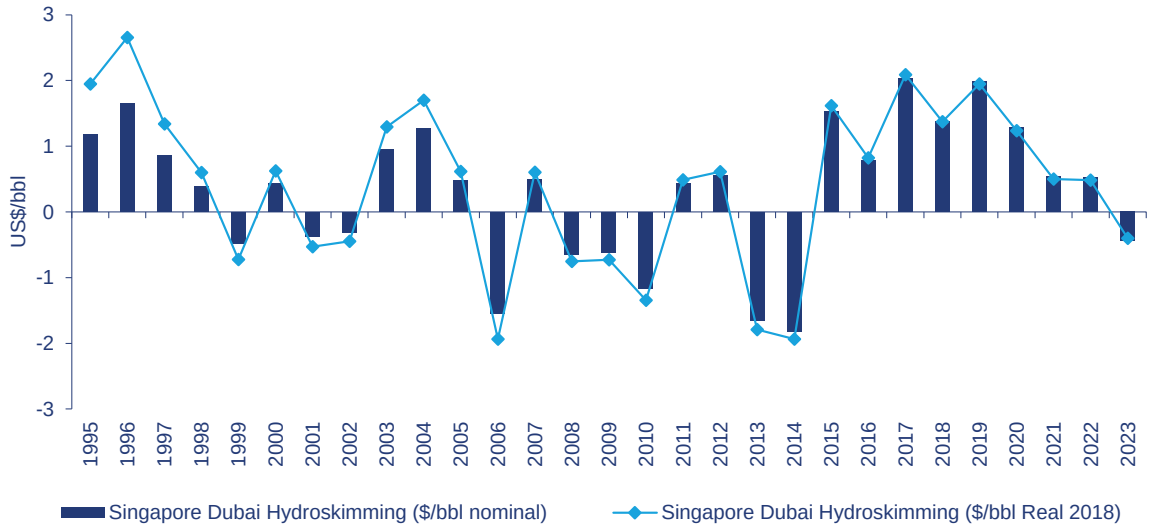


Source: Wood Mackenzie

Dubai hydroskimming margins fell in 2018 due to weaker fuel oil crack spreads. We expect a small recovery in 2019 but the implementation of IMO specification changes in 2020 mean that the market will be oversupplied with HSFO which means low margins for refiners that have a high yield of that product.

Post-2020, growing spare distillation capacity leads us to forecast that hydroskimming margins should weaken. The low level of hydroskimming margins reflects our view that refiners will not be running distillation units at high levels of utilisation for any sustained period. Further closures of refining capacity are likely to take place in Asia, particularly at smaller, less efficient plants in countries with mature economies. Our assumption is that refinery closures will take place in Europe, Asia and potentially the US post 2023 and this will reduce the amount of spare capacity and help to strengthen margins in the longer term. This period of weak margins could also slow down the pace of refinery investments, further contributing to stronger margins.

Figure 28 Dubai Hydroskimming Gross Refining Margin Forecast



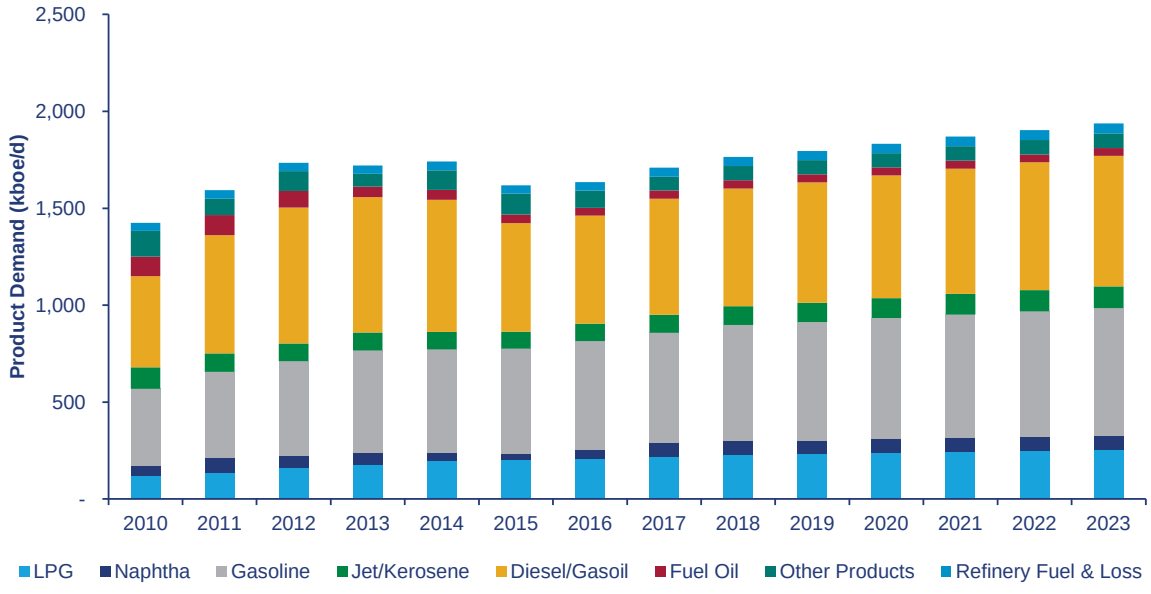
Source: Wood Mackenzie

5. Indonesia Downstream Overview

5.1. Oil products demand

Looking ahead, Indonesia's total product demand is forecast to grow from 1.8 million b/d in 2018 to 1.9 million b/d in 2023, at an average annual growth rate of 1.9%. Transportation demand accounts for around 87% of the demand increase, with road transport alone accounting for 77% of growth, From the residential and industrial sectors we also expect some moderate growth. Demand substitution by coal and natural gas is also under way in power generation.

Figure 29 Indonesia Product Demand



Source: Wood Mackenzie

LPG Conversion Program

Total LPG demand is forecast to increase at an average rate of 2.2% a year from 2018 through to 2023. LPG is mainly used in the residential sector for cooking purposes. The government has been pursuing an ambitious plan for a swift switching of residential kerosene to LPG, with a view that LPG's greater fuel economy helps a reduction in subsidies. The residential sector currently depends on traditional fuels for the bulk of its energy use, and as the country's GDP per capita grows going out to 2023, LPG is expected to increasingly replace traditional biomass used for cooking.

Biofuels

PERTAMINA started selling biodiesel blends at a select number of service stations in 2006. The proportion of biodiesel varied between 1% and 5% depending upon the prevailing economics of biodiesel production. From January 2009, the government stated it would implement mandatory biofuels blending. The mandates require the inclusion of biodiesel in all diesel/gasoil sold according to the following schedule: 1% in the transport sector, 2.5% in the industrial/commercial sector and 0.25% in the power generation sector. Those levels were planned to rise to 20% across all sectors by 2025. Ethanol is required to be blended at up to 5% in gasoline, rising to 15% by 2025.

These mandates seem to have finally spurred some growth in domestic biofuel consumption, but this has been limited to biodiesel, consumption of which is estimated to have reached 16,000 b/d in 2013. This represents around 6.8% of the road diesel demand.

In August 2013, the government issued a decree modifying its earlier biodiesel mandate to accelerate the implementation of biodiesel blending in different sectors. As per this decree, biodiesel use in subsidised diesel was increased from 10% to 15% in April 2015, 20% in 2016 and will then be increased to 30% in 2020. Biodiesel use in the power generation sector was mandated to increase from 7.5% in 2013 to 20% in 2014, 25% in April 2015 and to 30% by 2016 according to the decree issued in March 2015.

To implement this biodiesel policy, Indonesia can tap into the country's substantial potential to produce biofuels, as one of the two largest palm oil producers in the world and with an expanding sugar cane sector. It also has substantial biodiesel and fuel ethanol production capacity in place. However, with biodiesel in particular expected to remain significantly more expensive to produce than conventional diesel, biofuels will continue to require substantial government support to grow their market share. Rising prices for biodiesel feedstock will test the strength of that government support and as a result we forecast only modest growth in biodiesel consumption in Indonesia.

Ethanol is required to be blended at up to 5% in gasoline, rising to 15% by 2025. Disagreement over the price formula between the government and ethanol producers has resulted in no meaningful consumption of fuel ethanol. There are regulatory efforts under way to arrive at a price formula for ethanol that will result in supply becoming available. However, until it can be demonstrated that an appropriate policy can be implemented, we do not expect significant fuel ethanol use.

5.2. Refining capacity

There are nine refineries in Indonesia, with a total refining capacity of approximately 1.1 million b/d (57 Mtpa). The average refinery size is 127 kb/d. Six of these nine refineries are wholly owned and operated by PERTAMINA. PERTAMINA is also understood to be major shareholder for the TPPI refinery in Indonesia.

Of the nine refineries, four are hydroskimming refineries accounting for about 10% of the total capacity. There are three FCC refineries, one hydrocracking refinery and one hydrocracking and coking refinery.

Indonesia has a stated objective to reduce its reliance on imported petroleum products. It aims to meet this objective by increasing domestic product supply through refinery expansions and construction of new grassroots refineries with foreign partners. The Refinery Development Master Plan (RDMP) aims to improve PERTAMINA's refineries' operational capacity, complexity and competitiveness. The five main existing refineries in Balongan, Cilacap, Dumai, Balikpapan and Musi are part of the government's RDMP to increase national energy security and self-sufficiency.

In 2014, PERTAMINA planned to revamp its existing refineries with foreign partners. PERTAMINA entered agreements with Saudi Aramco, JX Nippon Oil & Energy Corp and China Petroleum & Chemical Corp (Sinopec) to progress its Refining Development Master Plan (RDMP). This initiative aims to improve PERTAMINA refineries' operational capacities, complexities and competitiveness. Subsequently, JX and Sinopec have called off their investment plan with only Aramco progressing talks with PERTAMINA.

In January 2015, the Indonesian government removed subsidies in the retail sector with the fall in global crude oil prices in order to generate interest in new grassroots refinery projects in Indonesia. Currently, PERTAMINA is in discussion with Rosneft for a new refinery project in Tuban, Indonesia.

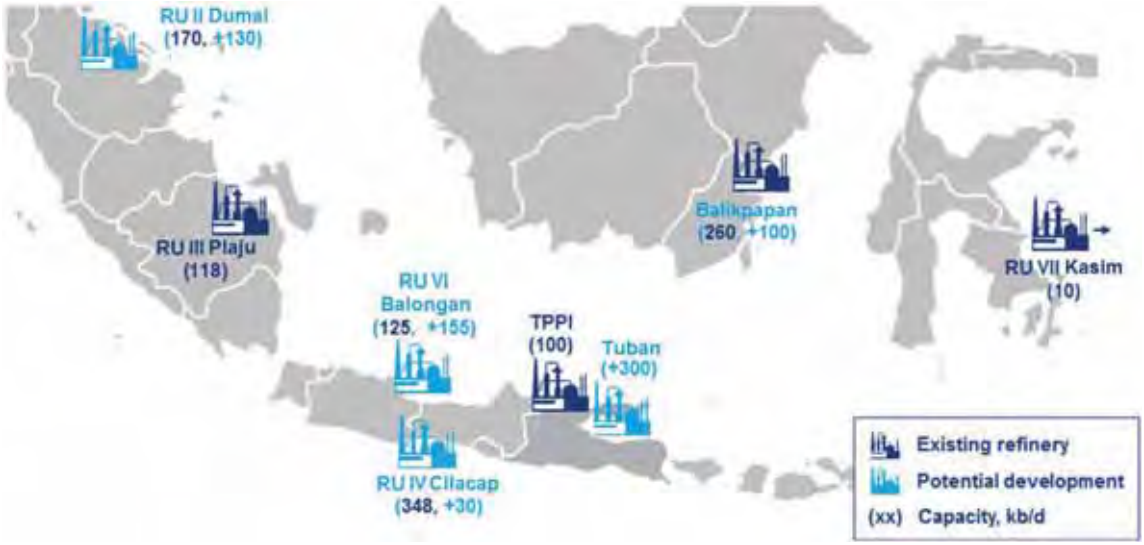
In May 2016, PERTAMINA and Saudi Aramco awarded a detailed engineering study to expand the Cilacap refinery from its current 348 kb/d to 370 kb/d refining capacity. In October 2016, PERTAMINA also entered into a licensing agreement with Axens for its residue upgrading project in Balikpapan. This project involves a 100 kb/d CDU expansion, addition of a new RFCC, diesel hydrotreater and LPG sulphur removal unit, to reduce the refinery's fuel oil production and increase its low-sulphur diesel production. The project is expected to be completed by mid-2021.

In January 2018, PERTAMINA appointed a consortium of partners to develop a new 300 kb/d grassroots refinery in Bontang. The partners involved were Oman Overseas Oil and Gas LLC and Cosmo Oil International. The final investment decision is expected in mid-2020 for a planned 2025 completion.

Separately, PERTAMINA is also replacing its semi-regen reformer for a continuous catalytic reformer (CCR) and adding an isomerisation unit as a part of the Blue sky project at the Cilacap refinery in 2018.

Although there are several discussions for new grassroots refineries in Indonesia, our view is that no new refinery would start-up before our investment horizon of 2025, with the exception for a 100 kb/d addition in the Balikpapan refinery in 2023. Overall, Indonesia's refining capacity will remain flat through to 2020, and increase by 100 kb/d to 1.2 Mb/d by end 2021.

Figure 30 Indonesian CDU Capacities*



Source: Wood Mackenzie

**Note: Excludes the 3.8kb/d Cepu refinery which processes local production from a nearby block and the 6kb/d hydroskimming Tri Wahan Universal refineries*

5.3. Imports and exports

Indonesia is net importer for most products in general, with the exception of fuel oil. We expect that trend to continue.

LPG imports into Indonesia have increased significantly underpinned by the shift from kerosene and traditional biomass to LPG for domestic cooking in the residential and commercial sector. Most of the LPG is sourced from the Middle East.

Naphtha is a net import product for Indonesia, which is largely used in gasoline blending and as a blending feedstock. Similar to LPG, most of it is sourced from the Middle East.

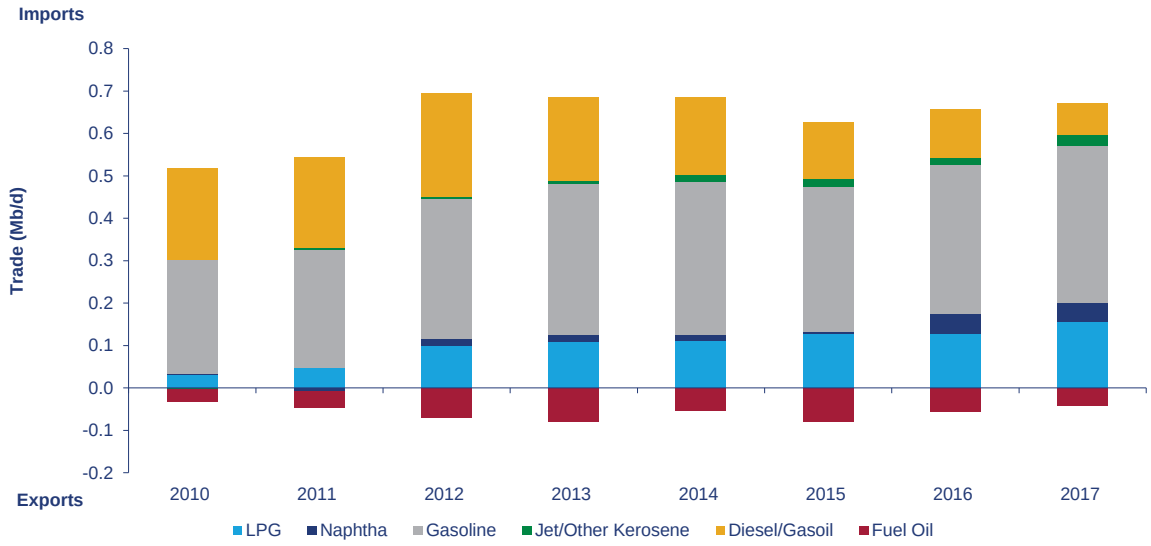
Gasoline is in a net trade deficit, driven by the domestic road fuel consumption in Indonesia. Most of which are sourced from the regional trading hubs in Singapore and Malaysia.

Indonesia is a net importer of jet/kerosene, underpinned by a growing aviation demand and a small domestic supply.

Most of diesel/gasoil consumption in Indonesia is met through imports, for its domestic road, industry sectors. It is sourced largely from Singapore. Net imports have remained high despite refineries maximizing diesel/gasoil production

Indonesia is a net exporter of fuel oil. The exports are largely to Singapore to meet its large bunker fuel oil demand.

Figure 31 Indonesian Net Trade



Source: Wood Mackenzie

5.4. Regional competitive analysis

Indonesia's downstream refining segment operates within the highly competitive refining sector of Southeast Asia which includes regional refiners such as Petronas, PTT, Petron, ExxonMobil, Shell, Chevron, Singapore Refining Company and PetroVietnam.

A number of measures can be used to compare and benchmark refinery performance by both asset and company.

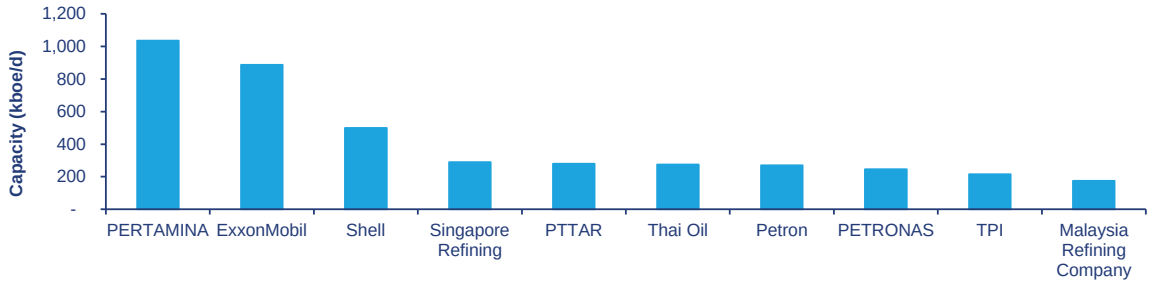
Size — refining is capital intensive and large facilities capture scale economies and have lower per unit operating costs. For the same configuration a larger facility would typically be more cost efficient and hence able to capture higher cash cost margin than a smaller facility.

PERTAMINA is understood to have the largest presence in Southeast Asia with a combined capacity of 1,035 kb/d. Most of the refineries are situated in Indonesia. Comparatively, Exxon (887 kb/d), Shell (500 kb/d) and Singapore Refining (290 kb/d) are the next few major refinery players in the region, with their facilities located mostly in Singapore. Across the top 10 companies, their average refining capacity in Southeast Asia is 417 kb/d.

Complexity — a measure of the refinery's capability to process difficult feeds such as heavy and high sulphur crudes, and to convert low value streams such as fuel oil to higher value transportation fuels. A higher complexity means a greater ability to take advantage of lower-cost crudes to produce a greater proportion of high value products, hence realising higher gross margins. The Nelson Complexity Index (NCI) is a typical indicator to compare the complexity levels of refineries. Typically a complex refiner realises a higher gross margin relative to a simple refiner under the same market environment.

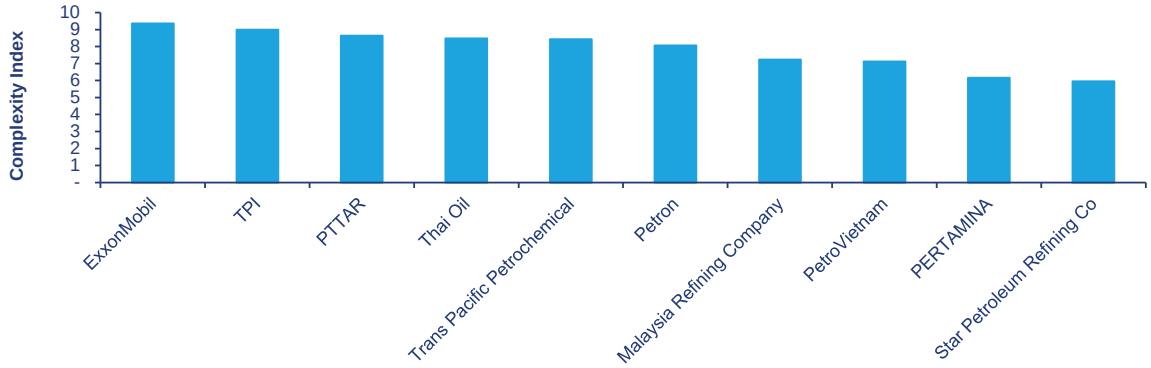
Most of the refineries in Southeast Asia have high complexities to maximize yields of high value products like gasoline and diesel for domestic markets. Currently, the average NCI is determined to be 7.85.

Figure 32 South East Asian Refining Capacity: Top 10 Companies



Source: Wood Mackenzie

Figure 33 South East Asian Top 10 Companies by Complexity Index (Weighted by CDU Capacity)



Source: Wood Mackenzie

6. Indonesia Marketing Industry Overview

The downstream marketing business in Indonesia is conducted by business entities legally registered in Indonesia that have obtained a business permit from the Ministry of Energy and Mineral Resources. Marketing business activities which require business licenses are processing, transportation, storage and trading. Although various business entities have obtained licenses to operate in one or more sectors, PERTAMINA is the only company which has full value chain integration in the downstream marketing business as it still owns the majority of the downstream infrastructure to process, transport, store and distribute oil products.

6.1. Infrastructure

Indonesia comprises more than 17,000 islands with over 900 of those permanently inhabited. Distributing oil products throughout Indonesia is a challenging task due to the vast geographical coverage and the spread of various inland demand areas separated by water bodies and land. In addition infrastructure constraints such as port limitations, limitations on vessel sizes and the location of terminals and inland depots add to the challenge. The supply chain can be long and involve complex logistics.

For the ease of sales and distribution of refined products, BPH Migas has divided the country into four main regions — WDN I to IV. WDN stand for Wilayah Distribusi Niaga in Bahasa, or commercial distribution area. WDN I comprise Sumatra and include cities such as Medan and Palembang. WDN II

comprises Java and includes cities such Bandung and Surabaya, and Bali. WDN III has the biggest geographical coverage and comprises the islands of Kalimantan, Sulawesi, Maluku and Irain Jaya. WDN IV comprises other smaller islands outside WDN I, II and III.

Many infrastructure-related assets are needed to support and complete the supply chain. There are 7 major terminals which can handle large vessels. There are another 7 transit terminals to handle smaller-sized ships. Most of these terminals are located on the Java Island where the main demand centre is located. There are another 107 fuel depots which have relatively smaller storage capacity as compared to the terminals, out of which 84 are coastal and 23 are inland. These depots are scattered across the country and are located near the demand areas.

With the exception of WDN IV, each of the distribution areas has its own refineries and domestic supply of refined products. There are three refineries in WDN I, namely PK Brandan (5 kb/d), Dumai (170 kb/d) and Musi (118 kb/d); another three refineries in WDN II, namely Balongan (125 kb/d), Cilacap (348 kb/d) and Cepu (4 kb/d); and two more refineries in WDN III which are Balikpapan (260 kb/d) and Kasim (10 kb/d). The local demand is mostly met by domestic supply. WDN II is an area with a very high oil product demand that attracts imports not only from other areas such as WDN I and III but also from outside the country.

In terms of distribution costs, it can vary from being low due to the existence of pipeline connections to the demand areas, to very high if the supply chain is long with multiple handling of oil products.

Figure 34 Sales and distribution areas of refined products



Source: Wood Mackenzie

Of the over 7,000 retail fuel filling stations in Indonesia, the vast majority are PERTAMINA-branded stations. PERTAMINA dominates the retail marketing sector and owns around 66% of the country's storage with 5.5 BL of capacity.

6.2. Key players

PERTAMINA maintained its retail and distribution monopoly for petroleum products until July 2004, when Shell and Petronas were granted the first licenses for retail sale of petroleum products.

Shell was the first foreign oil company to enter Indonesia's retail market with the opening of its first station in early 2005. This was followed by Petronas and Total. Although the downstream marketing industry has attracted more players since PERTAMINA's monopoly over non-subsidized fuels sales was revoked, progress has been slow to date. As of 2019, Shell currently has 96 retail fuel filling stations, while Total now has 18 stations out of over 7,000 retail stations. Petronas exited the retail fuel distribution business in 2012 and sold its retail assets to PERTAMINA. It still continues to operate on the commercial side of the business from its storage units. Although PERTAMINA no longer has a monopoly on the downstream sector since the liberalization, it still has close to a 100% market share for the retail sector.

These service stations built by foreign oil companies are mainly located in Greater Jakarta with a few stations found in Bandung and Medan. Before 2010, they could only sell non-subsidized fuels in their service stations. However, Petronas and AKR were selected to sell a limited volume of subsidized fuels in specific areas in 2010 and 2011. Although the downstream marketing sector has been gradually liberalized, the Government has been doing it in a tightly controlled manner through the PSO scheme offered to foreign oil companies. In 2019, BP jointly partnered with domestic private fuel distributor AKR to enter into Indonesia's retail fuel sector. It has since started operation at four service stations that sells gasoline since November 2018. The joint venture has plans to open up to 350 retail stations selling fuels and lubricants in the next decade.

It is likely that PERTAMINA will remain a dominant player for several years because of its established infrastructure and market presence.

6.3. Public service obligation

Until 2015, gasoline was heavily subsidised in Indonesia and imposed a high fiscal burden on the government. In a bid to contain the cost of subsidies, the government raised transport fuel prices substantially. Retail gasoline prices rose to 8,500 rupiah/litre (US$0.63/litre), after two consecutive hikes of 2,000 rupiah/litre in June 2013 and November 2014. In January 2015, the government removed all subsidies on gasoline, placing the fuel on a price float tied to market prices. As international oil prices have also declined, Indonesia's gasoline (RON 88) price was lowered to 7,600 rupiah/litre in January 2015, falling further to 6,600 rupiah in February, before stabilising at around 7,300 rupiah in the months through to May 2015. The diesel subsidies were also removed along with gasoline in January 2015.

INDONESIAN REGULATORY FRAMEWORK

Oil and Gas Regulation

Overview

Indonesia's oil and gas resources are deemed to be national assets owned and controlled by the state. Prior to the enactment of the Oil and Gas Law of 2001, oil and gas mining undertakings were controlled by the Government and exclusively carried out by the state petroleum enterprise, *Perusahaan Pertambangan Minyak dan Gas Bumi Negara* (or "PERTAMINA," our Company's legal predecessor), as the sole holder of the "authority to mine" in Indonesian territory. However, PERTAMINA was permitted to cooperate with other parties that were appointed or approved by the Minister of Energy and Mineral Resources to perform its mining undertakings. Investments by any party, foreign or domestic, in oil and gas exploration and production activities in Indonesia were done through a contractual arrangement with PERTAMINA, primarily in the form of production sharing arrangements, which include PSCs, technical assistance contracts ("TACs") and joint operating bodies ("JOBs") (as described in detail below). Under such production sharing arrangements, the oil and gas investor acted as a contractor to PERTAMINA, which held the overall management authority over exploration and production operations.

On November 23, 2001, the Oil and Gas Law of 2001 was enacted, which reformed the oil and gas upstream and downstream sectors in Indonesia by terminating the exclusive rights held by PERTAMINA. Unlike its predecessor law, Government Regulations in Lieu of Law No. 44 of 1960, which did not distinguish between types of oil and gas activities as they were both monopolized by PERTAMINA, the Oil and Gas Law of 2001 categorizes oil and gas activities into upstream and downstream activities. Upstream activities consist of exploration and exploitation of oil and gas resources, while downstream activities encompass processing, transporting, storing and trading of oil and gas.

Pursuant to the Oil and Gas Law of 2001, the oil and gas industry is regulated by the Minister of Energy and Mineral Resources through DGOG. The DGOG is responsible for ensuring that oil and gas related business activities in Indonesia are in compliance with oil and gas regulations. The Oil and Gas Law of 2001 also introduced two new governmental bodies, BPMIGAS and BPH MIGAS, which further regulate various aspects of the oil and gas industry and report to the DGOG. BPMIGAS, a non-profit, Government-owned legal entity, was the exclusive holder of the mine concession right in Indonesia and controlled and supervised upstream activities on behalf of the Government. The functions of BPMIGAS were, among other things, to:

- provide input to the Minister of Energy and Mineral Resources on his policies in preparing and offering areas of operations;
- provide advice on and execute cooperation contracts;
- review and provide input for the Minister of Energy and Mineral Resources to approve the first plan of development for a particular field that will be initially produced within a working area;
- approve the plan of development (other than the first plan of development) and work program and budgets;
- monitor cooperation contracts and existing production sharing arrangements and report their implementation to the Minister of Energy and Mineral Resources; and

- appoint sellers for the state's share of oil and gas produced from a working area, with the goal of maximizing benefit to the state.

On November 13, 2012, the Indonesian Constitutional Court (or *Mahkamah Konstitusi Republik Indonesia*) rendered Decision No. 36/PUU-X/2012, which dissolved BPMIGAS and, consequently, transferred all its duties and functions to the Minister of Energy and Mineral Resources. In response to the decision, the Government has enacted Presidential Regulation No. 95 of 2012 on the Transfer of Duties and Functions of Upstream Oil and Natural Gas Business Activities, which stipulates, among other things, that:

- performance of duties, functions and organization of BPMIGAS shall be transferred to the Minister of Energy and Mineral Resources until new oil and gas regulations are issued.

- any cooperation contract (*Kontrak Kerja Sama*) signed between BPMIGAS and any business entity or permanent establishment shall remain valid until its expiration.

- the entire processing of upstream oil and natural gas activities managed by BPMIGAS shall be continued by the Minister of Energy and Mineral Resources in accordance with the provisions of laws and regulations.

To implement the above regulation, the Government has issued (i) Presidential Regulation No. 9 of 2013 on the Implementation of Management of Upstream Natural Oil and Gas Business Activities, as amended by Presidential Regulation No. 36 of 2018 and (ii) Regulation of Minister of Energy and Mineral Resources No. 17 of 2017 on the Organization and Work Procedures of SKK MIGAS, as amended by Minister of Energy and Mineral Resources Regulation No. 53 of 2017 ("SKK MIGAS Regulations") for the purpose of, among others, the establishment of SKK MIGAS as an interim body supervising the upstream oil and gas business activity pending the issuance of a new oil and gas law. Pursuant to the SKK MIGAS Regulations all duties, functions, existing employees, organizational structure, funding and assets of BPMIGAS are transferred to SKK MIGAS which is directly controlled, monitored and evaluated by a Supervisory Commission led by the Minister of Energy and Mineral Resources.

BPH MIGAS, an independent governmental agency, is tasked with supervisory and regulatory functions over downstream activities in order to ensure the availability and distribution of fuels throughout the Indonesian territory and to promote gas utilization in the domestic market.

Pursuant to the Oil and Gas Law of 2001 and in conjunction with Government Regulation No. 31 of 2003 on the Change of Form of *Perusahaan Pertambangan Minyak dan Gas Bumi Negara (PERTAMINA)* to *Perusahaan Perseroan (Persero)*, PERTAMINA was converted into a profit based, state-owned company (*Persero*) in the form of a limited liability company, named PT Pertamina (*Persero*). Under the terms of the Oil and Gas Law of 2001 and the Upstream Regulation (as defined below), upon the establishment of BPMIGAS, all rights and obligations of PERTAMINA under all production sharing arrangements (but excluding TACs) then existing were transferred to BPMIGAS through novation agreements and BPMIGAS replaced PERTAMINA as the Government party to all such production sharing arrangements. Further, all of the fields that were designated as PERTAMINA's working areas prior to the enactment of the Oil and Gas Law of 2001 were transferred to BPMIGAS by operation of law. BPMIGAS then entered into a cooperation contract with PEP (the upstream subsidiary of our Company) to grant it working interests in all areas formerly designated as PERTAMINA's.

The Oil and Gas Law of 2001 is an umbrella legislation setting forth general principles to be further developed in a series of Government regulations, presidential decrees and ministerial decrees.

These include Government Regulation No. 35 of 2004, as amended by Government Regulations No. 34 of 2005 and No. 55 of 2009, on Upstream Oil and Gas Business Activities (the "Upstream Regulation") and Government Regulation No. 36 of 2004, as amended by Government Regulation No. 30 of 2009 concerning Downstream Oil and Gas Business Activities (the "Downstream Regulation"), which implement certain significant aspects of the Oil and Gas Law of 2001.

Upstream

After the implementation of the Oil and Gas Law of 2001, cooperation contracts were introduced to govern the working relationship and sharing of production between the Government and private sector contractors in the Indonesian oil and gas industry. Such cooperation contracts are similar to the production sharing arrangements applicable prior to the implementation of the Oil and Gas Law of 2001. The production sharing arrangements in existence prior to the implementation of the Oil and Gas Law of 2001 will remain in effect until they are terminated on their own terms.

Production Sharing Arrangements

Production sharing arrangements are based on five main principles:

- the contractors are responsible for all investments and production costs (exploration, development and production), including provision of capital to implement the agreed work program;
- the operational risk in performing upstream activities is borne by the contractors;
- the contractors' investment and production costs may be recovered against production (i.e. "cost recovery");
- profits are split between the state and the contractors at an agreed rate based on production after the cost recovery portion;
- ownership of tangible assets remains with the state; and
- overall management control remains with SKK MIGAS on behalf of the Government.

Generally, under production sharing arrangements, the operator is required to commit to spending a specified sum of capital to implement a work program approved by the Government. The negotiation of production sharing arrangement terms with potential contractors was handled primarily by the Ministry of Energy and Mineral Resources. Awards of work areas were based on either a competitive tender process and direct offer or whenever relevant under certain circumstances, tender direct offer, and the Indonesian Parliament had to be notified of the production sharing arrangement. Only one working area could be awarded to any one legal entity.

Such designation of an upstream oil and gas work area is specifically regulated under Minister of Energy and Mineral Resources Regulation No. 35 of 2008 on the Guidelines of Designation and Offering of Oil and Gas Working Area. Preparation of a working area for offering by way of a tender process is conducted by the DGOG at the Minister of Energy and Mineral Resources through technical and economic evaluation and data processing and with consideration by SKK Migas. After this process, the DGOG will then propose to the Minister of Energy and Mineral Resources the working area to be determined for offering through the tender process. In determining the working area, the Minister of

Energy and Mineral Resources will consult with the governor who has authority over the area where the working area is located. A tender for a working area is conducted over: (i) an area that has never been determined as a working area; (ii) a part of a relinquished working area as regulated under the relevant PSC; (iii) expired working areas; (iv) a part of working areas that has never been developed and/or is being or has been developed and is being relinquished by the PSC contractor; and/or (v) a part of working areas that has never been developed and/or produced that is being relinquished as proposed by Minister of Energy and Mineral Resources. The offering of a working area will be conducted by the DGOG, and will be announced through printed, electronic and other forms of media and other promotion of such working area. In relation to the offering, the DGOG will prepare and issue a bid document for every working area containing at least: (a) the bidding procedures; (b) geological and oil and gas potential information; (c) forecast of oil and gas reserve and production; and (d) the concept of the PSC.

Moreover, a party that proposes a direct offer for a certain working area must first conduct a joint study with the DGOG. The DGOG may include an appropriately qualified third party in the joint study. Once the joint study is completed and the Minister of Energy and Mineral Resources approves the joint study results, the area will be submitted to tender. However, the party that proposed the direct offer has the right to match the best bid from among the tender participants (the "Right to Match").

The designation of the working area for a direct offer process is conducted by the DGOG based on an evaluation of the joint study results. The working area must be an open area that has not been reserved by the DGOG for a tender round. In general, the steps for obtaining a PSC through a direct offer are similar to those for obtaining a PSC through an open tender, except that a direct offer involves the Right to Match.

In order to accelerate the increase of domestic production of oil and gas, the Upstream Regulation also provides that in cases of national emergency, with due observance and the benefit of the state, the President may approve requests for certain exceptions under production sharing arrangements and cooperation contracts, such as (i) the offer of participating interest to regional government-owned companies, (ii) the recovery of investment cost and operational cost, and (iii) our Company's payment obligation to the Government.

In 2012, the President of Indonesia issued Presidential Instruction No. 2 of 2012 on Increase of National Oil Production ("Presidential Instruction No. 2"). Presidential Instruction No. 2 instructed certain ministries, National Land Office, head of BPMIGAS, governors, mayors, heads of regency to take necessary, coordinated and integrated measures to support the government's plan to increase the national oil production at least 1.01 million barrel per day in 2014. Under Presidential Instruction No. 2, SKK MIGAS, as successor to BPMIGAS, has certain obligations, among others (i) to complete the process approvals for plan of development, work program and budget, authorization for expenditure within a certain period set out under Presidential Instruction No. 2, after submission by a contractor under a PSC; (ii) to complete procurement of goods and services within certain days as set out under Presidential Instruction No. 2; (iii) to increase the efficiency of operational and optimize production facilities; (iv) to optimize production and development fields by using Enhanced Oil Recovery technology; (v) to increase the management and supervision on the implementation of cooperation contracts (including the utilization of shared facilities); (vi) to accelerate the development of new, marginal and idle fields; and (vii) to optimize suspended wells.

Set out below are the most common types of contracts in the Indonesian upstream oil and gas sector:

PSCs

PSCs were the primary production sharing arrangement used prior to the Oil and Gas Law of 2001 to award contractors the rights to explore for oil and gas reserves prior to commercial production.

PSCs were awarded for a term specified by contract, subject to the discovery of commercial quantities of oil and/or gas within a certain period. PSCs created under the prior regulatory framework will remain effective until they are terminated on their own terms. Under a PSC, a contractor is generally required to relinquish specified percentages of the initial contract area by specified dates, except for the areas where oil and gas have been discovered.

SKK MIGAS has replaced PERTAMINA as the Government party to all existing PSCs. SKK MIGAS is responsible for managing all PSC operations; assuming and discharging the contractor from all taxes, other than Indonesian corporate taxes (including the tax on interest, dividends and royalties); obtaining the required approvals and permits; and approving the contractor's work program, budget and plan of development (except the initial plan of development). The responsibilities of a contractor under a PSC generally include advancing necessary funds and capital expenses related to the project, furnishing technical aid and preparing and executing the work program and budget.

Under each PSC, the contractor and SKK MIGAS share the total production in any given period in a ratio agreed between the parties under the terms of that PSC. The contractor generally has the right to recover all funding and development costs, as well as operating costs, against available revenues generated by the PSC after deduction of FTP. Under FTP terms, the parties are entitled to receive a specified portion of total production each year from each production zone or formation, before any deduction for recovery of operating and other costs. The contractor is obligated to pay Indonesian corporate taxes on its specified profit share, including FTP, either at the Indonesian corporate tax rate in effect at the time the PSC is executed or at the prevailing tax rate pursuant to the PSC.

The total of the contractor's share of FTP, production attributable to cost recovery and post-tax profit share represents its net crude entitlement for a given period.

All PSCs in Indonesia are subject to DMO, under which the contractor is required to supply the domestic market at a reduced price with 25% of the contractor's share of total crude oil production under the relevant PSC. This reduced price varies among each PSC, but is in each case calculated at the point of export. Under the prior regulatory framework, DMO did not apply to natural gas production. Under the Oil and Gas Law of 2001, DMO now also applies to natural gas production.

On February 25, 2016, the Government implemented Regulation of the Minister of Energy and Mineral Resources No. 06 of 2016 on Provisions and Procedures of the Stipulation of Allocation and Utilization including Price of Natural Gas, as partially revoked by the Minister of Energy and Mineral Resources Regulation No. 32 of 2017 on the Utilization of and Sales Price for Flare Gas in Upstream Oil and Gas Business Activities ("MR No. 06/2016"). MR No. 06/2016 sets out the Government's policy in relation to the allocation and utilization of natural gas supplied under DMO for domestic consumption and establishes allocation priority towards certain industries. Such industries include the oil and gas industry, the fertilizer industry and the power industry.

MR No. 06/2016 provides that a PSC contractor must make available a specific volume of natural gas for DMO based on an allocation stipulated by the Indonesia Ministry of Energy and Mineral Resources ("MEMR"). The MEMR will stipulate such allocation taking into account the following priorities: (i) to support the Government's program in the provision of natural gas for transportation, households and small-scale consumers, (ii) to improve the production of national oil and natural gas, (iii) for fertilizer industries, (iv) for natural gas-based industries, (v) for electricity generation, and (vi) for other industries using natural gas as fuel. Further, a PSC contractor can only export the natural gas it produces if at least one of the following conditions apply: (a) the needs of natural gas for domestic consumers have been fulfilled, (b) there is no appropriate infrastructure available domestically, or (c) the purchasing power of domestic consumers is not able to fulfil the economics of the gas field. The enactment of MR No. 06/2016 does not affect the validity of allocation and utilization obligations pursuant to DMO in existing PSCs.

With regard to natural gas for the purposes of electricity generation, after the implementation of Minister of Energy and Mineral Resources Regulation No. 45 of 2017 on the Utilization of Natural Gas for Power Generation ("MR No. 45/2017"), a holder of a gas trading license (a "Gas Trading Entity") may sell natural gas to an Independent Power Producer ("IPP") or to PLN, subject to the DMO requirements set out by Minister of Energy and Mineral Resources, provided that the Gas Trading Entity has the appropriate natural gas infrastructure and facilities to supply natural gas to the relevant power project operated by such IPP or PLN. MR 45/2017 also sets the maximum price of pipeline natural gas at the plant gate which can be purchased by an IPP or PLN at 14.5% of the Indonesian Crude Price ("ICP"). If an IPP or PLN cannot source domestic pipeline natural gas at a price lower than 14.5% of the ICP, it: (i) may instead purchase LNG at the plant gate, provided that the price of such LNG is lower than the price of any available pipeline natural gas, and (ii) must purchase domestic LNG, if the price of such domestic LNG is the same as (or below) the price of imported LNG. As such, MEMR 45/2017 aims to prioritize the use of domestic pipeline natural gas and domestic LNG over imported LNG. If the IPP or PLN cannot satisfy the conditions above, the Minister of Energy and Mineral Resources can set out further policies to ensure the supply of gas to power generators, which take form of the allowing of an IPP or PLN to import LNG at a price higher than 14.5% of the ICP.

On September 5, 2018, the Minister of Energy and Mineral Resources issued Regulation No. 42 of 2018 on the Priority of Crude Oil Utilization for the Fulfillment of Domestic Needs ("Regulation 42/2018"). Regulation 42/2018 requires us and or/other Indonesian oil processing license (*izin usaha pengolahan minyak bumi*) holders to source crude oil supply from local upstream oil and gas contractors before importing crude oil. In implementing this requirement, upstream oil and gas contractors must first offer their share in crude oil production to us and/or other Indonesian oil processing license holders at least three months before the commencement of the recommendation period for crude oil export by the local upstream oil and gas contractors, subject to negotiation between the parties. We are required to report the result of these negotiations to the DGOG. We may directly appoint upstream oil and gas contractors for the purchase of the crude oil and enter into contracts of up to one year in duration.

Prior to the enactment of the Oil and Gas Law of 2001, each PSC contained a right for PERTAMINA to demand from contractors a specified percentage of their total rights and obligations under that PSC, which is to be offered to either PERTAMINA or a limited liability company designated by PERTAMINA, the shareholders of which must be owned by Indonesian nationals (the "Indonesian Participation Arrangements" or "IPs"). This right lapses if not exercised by PERTAMINA within three months after contractors notify PERTAMINA of their first discovery of petroleum or gas which can be developed commercially within the contract area. Each cooperation contract executed after the date of enactment of the Oil and Gas Law of 2001 similarly contains a right for SKK MIGAS to demand from contractors a specified percentage of their total rights and obligations under that cooperation contracts, which is to be offered to either a local government-owned company to be designated by the local government within which the contract area is located or an Indonesian national company to be designated by the Minister of Energy and Mineral Resources. This requirement to offer is also governed by Regulation of the Minister of Energy and Mineral Resources No. 37 of 2016 on the Offering of 10% of Participating Interests in Oil and Natural Gas Work Areas. The requirement to offer does not apply to extensions of the exploration periods within a PSC. The PSC contractor is required to bear the regional government enterprise's costs, including historic exploration costs, through to the end of the PSC. Such costs may be recovered through the regional government enterprise's portion of production and cannot be subject to interest. The recovery of costs must be carried out to ensure that the regional government enterprise receives a portion of the production. If the regional governments enterprise rejects the 10% participating interest offer, the PSC contractor is required to offer the 10% participating interest to a state-owned company. However, the contractor is not required to bear the state-owned company's costs.

Upon and in consideration for the exercise of such rights, the party whom the right is exercised in favor of reimburses the relevant contractors for an amount equal to that specified percentage of the

sum of the costs incurred up to the date of the transfer under the PSC or the cooperation contract, as the case may be. Such reimbursement includes proportion of the compensation bonus and production bonuses previously paid by the relevant contractors. These amounts are to be paid either directly to the relevant contractors in cash or through production installments, depending on the terms of the relevant PSC or cooperation contract.

On December 20, 2010, the Government issued Government Regulation No. 79 of 2010 regarding Cost Recovery and Income Tax Treatment in the Upstream Oil and Gas Business, as amended by Regulation No. 27 of 2017 ("GR 79/2010"). GR 79/2010 regulates cost recovery under PSCs or cooperation contracts, supplementing the standard provisions relating to cost recovery set out in such contracts. Under GR 79/2010, certain requirements are established for the reimbursement of operational costs. Among other things, the petroleum operation must be in conformity with the work program and budget approved by SKK MIGAS for operational costs to be reimbursable. GR 79/2010 contains transitional provisions permitting provisions in PSCs or cooperation contracts entered into prior to its enactment to remain effective. To the extent that such provisions do not clearly regulate certain matters governed by GR 79/2010, they must be adjusted to conform with GR 79/2010 within three months after the issuance thereof.

On January 16, 2017, the Minister of Energy and Mineral Resources introduced a gross split system for production sharing contracts ("Gross Split PSCs") through the enactment of Regulation No. 08 of 2017, as amended by Regulation No. 52 of 2017 on Gross Split Production Sharing Contracts ("Regulation 8/2017"). The Gross Split PSCs does not contain the traditional cost recovery regime that provides reimbursement of operational costs to the Government's contractors. In the gross split system, the production sharing portion is calculated by adjusting the base split value against the adjustment components. The base split value is a ratio between the Government's and the contractor's respective shares of oil and gas production, which is used for determining the production sharing portion upon the approval of a plan of development. Regulation 8/2017 stipulates the base split value as follow:

a. in crude oil production – 57% for Government's portion and 43% for contractor's portion; and

b. in natural gas production – 52% for Government's portion and 48% for contractor's portion.

The adjustment components include variable components (status of working area, field location, depth and type of reservoir, availability of infrastructure, contents of carbon dioxide and hydrogen-sulfide, specific gravity of crude oil, local content level during the period of field development and production stage) and progressive components (prices of crude oil and natural gas and production cumulative amount of crude oil and natural gas).

Further, Regulation 8/2017 specifies that the Gross Split PSCs must have at least the following requirements:

a. ownership of the natural resources remains with the Government until the hand-over of the project by the contractor (up to the delivery point);

b. SKK Migas has control over the operational management of the oil and gas working areas; and

c. all capital and operational costs are borne entirely by the contractor.

Following the enactment of Regulation 8/2017, the system of gross split will only apply to new PSCs and all cooperation contracts in the Indonesian oil and gas sector entered into prior to the date of enactment will remain enforceable until their expiration date. If extensions of these cooperation contracts are approved in the future, the contractors will at such time have the option to implement the gross split system or otherwise to maintain the existing cost recovery system. Nonetheless, the gross split system must be applied to all upcoming cooperation arrangements made by and between the Government and contractors for conducting exploration and exploitation in oil and gas working areas, including towards new contacts which areas managed by us.

The cooperation contracts that have replaced the production sharing arrangements (including PSCs) in existence prior to the Oil and Gas Law of 2001 are also commonly referred to as "production sharing contracts" and share many of the characteristics of PSCs described above. Please see "— Upstream — Cooperation Contracts" for more information on these contracts.

Under Article 2(1) of Minister of Energy and Mineral Resources Regulation No. 23 of 2018 as amended by Minister of Energy and Mineral Resources Regulation No. 28 of 2018 and as further amended by Minister of Energy and Mineral Resources Regulation No. 3 of 2019 on the Management of Oil and Gas Working Areas During Final Cooperation Contract Period (**"MR 23/2018"**), the Minister of Energy and Mineral Resources shall determine the management of oil and gas work areas whose underlying cooperation contracts have expired. Such management can be in the form of:

a. extension of cooperation contracts by the contractors;

b. management by PT Pertamina (Persero); or

c. joint management between the contractors and PT Pertamina (Persero).

Moreover, the Indonesian Supreme Court through its Decision No. 69/P/HUM/2018 indicated that the list in Article 2(1) of MR 23/2018 is not based on an order of priority, meaning that no preference should be given to contractors over Pertamina.

TACs

TACs are another form of production sharing arrangement created under the regulatory framework that preceded the Oil and Gas Law of 2001. TACs were awarded for fields having prior or existing production and are valid for a specified term. The oil or gas production is divided into non-shareable and shareable portions. The non-shareable portion represents the production which is expected from the field (based on historic production) at the time the TAC is signed. Under a TAC, the non-shareable portion declines annually. The shareable portion corresponds to the additional production resulting from the operator's investment in the field and is further split in the same way as for a PSC. The Upstream Regulation provided that existing TACs remain with PERTAMINA (now PT Pertamina (Persero)) and are not renewable after the expiry of the initial term.

JOBs

JOBs are another form of production sharing arrangement created under the regulatory framework that preceded the Oil and Gas Law of 2001. In a JOB, operations are conducted by a JOB headed by the Issuer and assisted by one or more private sector energy companies through their respective secondees to the JOB. In a JOB, the Issuer is entitled to a specified percentage of the working interest in the project. The balance, after production is applied towards cost recovery and cost bearing as between the Issuer and the private sector participants, is the shareable portion which is generally split in the same

way as for an ordinary PSC. Unlike TACs, the Upstream Regulation transferred the rights to operations under existing JOBs from the Issuer to SKK MIGAS by law. However, the working interest that was held by PERTAMINA under the JOB was transferred to our Company. JOBs are not renewable after the expiry of their initial term.

Cooperation Contracts

The Oil and Gas Law of 2001 has replaced production sharing arrangements with cooperation contracts. These cooperation contracts can be similar in form to production sharing arrangements, but may be in a different form. Regardless of the form, certain key principles remain the same as the PSCs. For example, title over resources in the ground remains with the Government (and title to the oil and gas lifted for the contractor's share passes at the point of transfer, usually the point of export), ultimate management control is with SKK MIGAS, and capital requirements and risks are to be assumed by the contractors. These cooperation contracts are to be entered into with SKK MIGAS and thereafter notified in writing to the Parliament. Only one working area will be given to any legal entity. Cooperation contracts can be made for a maximum term of 30 years and can be extended for a maximum of 20 years. Cooperation contracts are divided into exploration and exploitation stage. The exploration stage is for a term of six years, subject to only one extension for a maximum of four years.

In August 2018, the Government issued Presidential Regulation No. 66 of 2018 to further amend Regulation No. 61 of 2015 on Collection and Utilization of Palm Oil Estate Fund, and the Ministry of Energy and Mineral Resources issued Regulation No. 41 of 2018, as amended by Regulation No. 45 of 2018, on Provision and Utilization of Biodiesel Fuel under Financing by the Indonesian Oil Palm Estate Fund. ("MR 41/2018"). MR 41/2018 regulates that an oil fuel business entity must mix biofuel in the form of biodiesel with oil fuel in the form of gas oil in accordance with the mandatory minimum utilization of biofuel in the form of biodiesel sets out by the Minister of Energy and Mineral Resources. The requirement for mandatory use of 20 per cent. locally-blended biodiesel ("B20 fuel") in Indonesia ("Mandatory B20") is further regulated under Regulation of the Minister of Energy and Mineral Resources No. 32 of 2008 as amended by Minister of Energy and Mineral Resources Regulation No. 12 of 2015 on Supply, Utilization of and Trade System of Biofuel as Alternative Fuel. Mandatory B20 is now applicable to both the PSO and non-PSO sectors, which has resulted in the compulsory sale of B20 fuel at all gas stations in Indonesia, including those managed and operated by us.

The Upstream Regulation reiterates the Indonesian Participation Arrangement obligation in cooperation contracts, although the procedure for, and timing of, offering such an interest has been modified. The Minister of Energy and Mineral Resources has a right to request that a contractor who wishes to sell its participating interest under a production sharing arrangement grant a right of first offer to national enterprises such as regional government-owned companies, central government-owned companies, cooperatives, small scale businesses and Indonesian companies wholly owned by Indonesians. Under the Upstream Regulation, such an offer must be made on an "arms-length" basis. These modifications are applicable only to the cooperation contracts entered into after the issuance of the Oil and Gas Law of 2001.

Coal Bed Methane

The Upstream Regulation introduced regulations on CBM. CBM is defined as natural gas (hydrocarbon) with methane gas as its main component, naturally brought about in the coalification process in a trapped and absorbed condition in coal and/or coal layers. The Upstream Regulation states that the development of CBM shall be regulated by Ministerial Decree.

On November 12, 2008, the Minister of Energy Mineral Resources issued Regulation No. 36 of 2008 regarding exploitation of CBM (the "CBM Regulation"). The CBM Regulation confirms that

CBM is a non-renewable strategic natural resource that constitutes a national asset controlled by the Government. Control over CBM assets is exercised by the Government in the form of mining concessions. The management and development of CBM tracks the regulations in the oil and gas business, while oversight and supervision of CBM activities is centralized in the DGOG. The procedures for the award of work areas of CBM track the same regulations applicable to conventional oil and gas business.

According to the CBM Regulation, there are four areas in which CBM may be exploited:

- an open area;
- a working area of oil and/or gas;
- a coal contract of work working area; and/or
- a concession area of coal with a maximum size of 3,000 km^2.

If the CBM to be exploited is located in an existing working area of oil and/or gas subject to the PSC, the CBM Regulation grants the existing contractors under the PSC first priority in the right to exploit CBM in the CBM. Such contractors must (i) fulfill its commitment to explore for oil and/or gas in such area for the first three years pursuant to the PSC; (ii) perform a joint evaluation of the CBM reserves with the DGOG; and (iii) submit to the DGOG a proposal to acquire interest in such CBM working area.

Geothermal Regulation

The geothermal energy industry in Indonesia was previously regulated under Presidential Decree No. 22 of 1981, as amended by Presidential Decree No. 45 of 1991 (the "Old Geothermal Regulation"). Under the Old Geothermal Regulation, which was based on a "total project" concept, PERTAMINA was authorized to undertake exploration and exploitation of geothermal energy resources, to generate electricity from the geothermal energy, and to sell the geothermal energy and/or electricity produced to PLN and other buyers. Therefore, under the Old Geothermal Regulation, when a contractor under a JOC with Pertamina discovered geothermal energy reserves in a commercial quantity as agreed under the JOC and the electricity sales contract, the contractor was automatically allowed under the JOC to exploit the geothermal energy, generate electricity from such geothermal energy and sell the electricity (or the geothermal energy) to PLN.

The Old Geothermal Regulation was revoked by Presidential Decree No. 76 of 2000 ("PD 76") and as a result, geothermal contractors no longer enjoy the automatic right to exploit discovered geothermal energy reserves and sell the electricity to PLN. Under PD 76, the activities governed by the Old Geothermal Regulation regime was divided into two different business activities: (i) the exploration for and exploitation of geothermal energy; and (ii) the generation of electricity from geothermal energy.

The exploration and exploitation of geothermal energy is now regulated under Law No. 21 of 2014 concerning Geothermal Energy ("Law 21"). Each of PD 76, Law 21 and Government Regulation No. 7 of 2017 regarding Geothermal for Indirect Utilization ("GR 7") states that all cooperation contracts for the exploration and exploitation of geothermal resources executed prior to the effectiveness of each of PD 76, Law 21 or Government Regulation No. 59 of 2007 on Geothermal Business Activities ("GR 59") shall remain in force until the expiry of such contract, provided that (i) pursuant to PD 76, the outcome of a renegotiation conducted by Restructuring and Rehabilitation Team of PLN does not

determine otherwise; and (ii) pursuant to Law 21, an exploitation of the relevant working area must have been conducted at the latest by December 31, 2014. Furthermore, GR 7 also does not regulate the obligation to return the undeveloped concession within a certain period unlike the previous regulation which provided that if the geothermal working area existed prior to GR 59 and there was no cooperation contract relating to such area or exploitation activity in the working area by December 31, 2014, then the holders of such authority, permit or contract are obliged to return the relevant working area to the Government.

Under Law 21, a legal entity (in the form of a state-owned company, regional state-owned company, cooperative or private legal entity located and conducting its business activities in Indonesia) is required to obtain a Geothermal License (*Izin Panas Bumi*, "IPB") in order to utilize geothermal energy. The IPB is issued by the Minister of Energy and Mineral Resources. Geothermal energy utilization is categorized as either direct or indirect utilization. Under direct utilization, geothermal energy is used for a purpose other than generating electricity, such as tourism, agribusiness and industry. Under indirect utilization, geothermal energy is used to generate electricity. However, the indirect utilization of geothermal energy in order to generate electricity is also specifically governed under and subject to Law No. 30 of 2009 on Electricity ("Law 30").

Under Law 30, a company must obtain a business license or an operation license from the Government or applicable regional government in order to supply electricity (which includes the generation, transmission, distribution and sale of electricity). A business license is required for a company that primarily provides electricity to the public, while an operation license is required for a company that sells electricity in excess of its private use to the public. A holder of a business license must (i) provide electric power according to the prevailing quality and reliability standards set forth by the Government, (ii) provide high levels of service to the public and its consumers, (iii) comply with electricity safety regulations, and (iv) prioritize domestic products and labor for use in its business.

Companies wishing to sell their electricity must enter into a power purchase agreement with PLN. Pursuant to Regulation of Minister of Energy and Mineral Resources No. 17 of 2014 on the Purchase of Electricity from Geothermal Power Plant and Geothermal Steam Used in Geothermal Power Plant, PLN must : (i) purchase electricity from geothermal power generators holding an Electricity Supply Business License (*Izin Usaha Penyediaan Tenaga Listrik*) which use geothermal energy from geothermal business licenses, concessions, and contracts; or (ii) purchase geothermal steam from geothermal business licenses, concessions, and contracts for its geothermal power plants, as specified in the regulation.

The current applicable geothermal electricity sales price is regulated under Minister of Energy and Mineral Resources Regulation No. 50 of 2017, as amended by the Minister of Energy and Mineral Resources No. 53 of 2018 on Amendment to Regulation of the Minister of Energy and Mineral Resources No. 50 of 2017 regarding the Utilization of Renewable Energy Source for Electricity Supply ("Regulation 50/2017"), which also regulates the benchmark for determining the electricity purchase price by PLN for renewable energy. Regulation 50/2017 does not determine the exact electricity sales price and instead it refers to the primary cost of power generation by PLN at the local and national level (*Biaya Pokok Penyediaan Pembangkitan* or "Power Generation BPP"). The Power Generation BPP used to determine the electricity sales price is the Power Generation BPP as determined by Minister of Energy and Mineral Resources in the previous year. Regulation 50/2017 stipulates the following electricity sales price for geothermal power plants:

(a) in the event that the Power Generation BPP at the local electricity system is above the average national Power Generation BPP, the electricity sales price should be no higher than the Power Generation BPP at the local electricity system; or

(b) in the event that the Power Generation BPP at the local electricity system in the Sumatera, Java and Bali or other local electricity system is equal to or below the average national Power Generation BPP, the electricity sales price may be agreed between PLN and the geothermal power plant developers.

The electricity sales price agreed between PLN and the geothermal power plant developers must be approved by the Minister of Energy and Mineral Resources.

Downstream

Under the Oil and Gas Law of 2001 and Downstream Regulation, downstream oil and gas business activities include processing, transportation, storage and trading:

Processing

Under the Oil and Gas Law of 2001, processing is defined as activities carried out to refine crude oil and/or natural gas, obtaining parts of oil and gas products and improving the quality and the added-value of crude oil and natural gas. Field processing is excluded from this definition by the Oil and Gas Law of 2001 as it is considered an aspect of exploration and exploitation activities. Pursuant to the Downstream Regulation, the processing of natural gas into LNG, LPG and/or gas to liquefied form is considered a downstream business activity if it is intended to obtain gain and/ or profit and is not the continuation of upstream business activities.

Transportation

Transportation covers the activities of transferring crude oil, natural gas, fuel oil, gas fuel and/or its processed products from a working area or from the storage and processing facilities, including the transportation of natural gas through transmission and distribution pipelines, for commercial purposes.

Storage

Storage covers the activities of receiving, collecting, stocking up and discharging of crude oil, natural gas, fuel oil, gas fuel and/or its processed for commercial purposes.

Trading

Trading covers the purchase, sales, exportation and importation of crude oil, natural gas, fuel oil, gas fuel and/its processed products, including trading of natural gas through pipelines.

Pursuant to the Downstream Regulation, trading business activities are divided into two types:

- *General trading (wholesale):* sales, purchase, export and import activities of crude oil, natural gas, fuel oil, gas fuel, other fuel and/or its processed products on a large scale, by an entity that controls or owns storage facilities and holds a General Trading (Wholesale) Business License, which authorizes the holder to distribute the products to end consumers using a certain trademark used or owned by the holder; and

- *Limited trading (trading):* sales, purchase, export and import activities of crude oil, natural gas, fuel oil, gas fuel, other fuel and/or processed products on a large scale, by an

entity that does not control or own storage facilities and holds a Limited Trading Business License, which authorizes the holder only to distribute products to consumers/users that control/own port facilities and/or receiving terminals.

Licenses

Pursuant to the Oil and Gas Law of 2001 and the Downstream Regulation, in order to conduct oil and gas downstream business activities, a business entity must first obtain a business license from the Minister of Energy and Mineral Resources. A business license shall only be granted to a business entity that has complied with all applicable administrative and technical requirements.

In line with the four types of downstream business activities, there are four types of business licenses (each, a "Business License"):

- Processing Business License;
- Transportation Business License;
- Storage Business License; and
- Trading Business License, which is either a General Trading (Wholesale) Business License or a Limited Trading (Trading) Business License.

If a business entity conducts processing activities with transportation, storage and/or trading activities as a continuation of such processing activities, it only needs to obtain a Processing Business License. However, if transportation, storage and/or trading activities are conducted by a business entity other than as the continuation of any processing activities, it must obtain the respective Transportation, Storage or Trading Business Licenses separately.

The ultimate authority to grant Business Licenses belongs to the Minister of Energy and Mineral Resources, through the DGOG. However, under the Oil and Gas Law of 2001, if oil and gas downstream business activities relate to regional interests, the Minister of Energy and Mineral Resources may consult with the relevant regional government and issue a Business License upon its recommendation. In addition, as provided in the Downstream Regulation, the Minister of Energy and Mineral Resources may delegate its authority to grant a Business License for certain activities to regional governments, related government institution and/or the Investment Coordinating Board of the Republic of Indonesia (*Badan Koordinasi Penanaman Modal* or "BKPM"). The delegation of authority is undertaken for efficiency and cost reduction purposes. In ascertaining whether to delegate authority, the Minister of Energy and Mineral Resources assesses the capabilities of the relevant business entity as well as factors such as foreign ownership and whether investment facilities are utilized.

PSO

Under the Oil and Gas Law of 2001, the Government is responsible for the distribution of oil and gas products within Indonesia. This obligation is commonly known as the public service obligation.

Prior to the enactment of the Oil and Gas Law of 2001, PERTAMINA was the sole entity allowed to conduct activities pursuant to the PSO. However, after the enactment of the Oil and Gas Law of 2001 and the passage of PR 43/2018 and partly revoked by Presidential Regulation No. 66 of 2018, a business entity can be assigned by the Government to conduct activities pursuant to the PSO by a

direct appointment and/or through a selection process. In conducting the PSO, the relevant business entity is prohibited from exporting certain types of fuel oil products that are required to be supplied and distributed for PSO purposes. However, such business entity may import, subject to a recommendation from the Minister of Energy and Mineral Resources and approval from the Minister of Trade, such fuel oil products if the domestic production is not sufficient to fulfill the demand in Indonesia.

The assignment of the legal entity to supply certain types of oil to fulfill the domestic demand is further regulated under Regulation of BPH MIGAS No. 09 of 2015 on the Assignment of the Legal Entity to Supply and Distribute Certain Type of Oil Fuels and Type of Oil Fuels for Specific Assignment. Under this regulation, the assignment of the business entity can be conducted through:

Direct appointment and/or selection process

To be eligible for the direct appointment and/or the selection process for certain types of oil fuels, a business entity must meet the following criteria:

- it must have a General Trading (Wholesale) Business License (*Ijin Usaha Niaga Umum*);
- it must own the storage, and distribution facilities;
- it has operational buffer reserves of oil fuels; and
- it meets the administrative, technical, financial, commercial and other requirements, as stipulated by BPH MIGAS.

In addition to the above, a business entity must meet the following criteria for direct appointment for certain types of fuels:

- it must protect domestic refinery assets and plan for long-term development;
- it must guarantee domestic availability and supply of certain types of oil fuels;
- it must take measures to manage the short-supply of oil fuels;
- it must supply remote areas and areas without a working market mechanism; or
- if there is only one General Trading (Wholesale) Business License holder to conduct the supply and distribution of certain types of oil fuels in one commercial distribution area.

BPH MIGAS determines whether the above criteria are met.

Mandate

To be eligible for a mandate for supply and distribution of type of oil fuels for specific appointment, a business entity must meet the following criteria:

- it must have a General Trading (Wholesale) Business License (*Ijin Usaha Niaga Umum*);

- it must own oil fuels processing facilities;
- it must own oil fuels storage facilities;
- it must own oil fuels distribution facilities; and
- it meets the administrative, technical, financial, commercial and other requirements, as stipulated by BPH MIGAS.

If there are more than three eligible business entities for the mandate, BPH MIGAS will conduct a selection process. BPH MIGAS determines whether the above criteria are met.

The appointment of the PSO distributor will be set forth in a decree by BPH MIGAS, which will specify the following information: (i) identity of the appointed business entity; (ii) the rights and obligations of the appointed business entity; (iii) the term of appointment; (iv) the volume and type of fuel oil products to be distributed; (v) type and volume of distributor; (vi) the area designated; (vii) sanction in the form of assignment of oil fuels volume to other business entities; and (viii) force majeure conditions.

Based on PR 43/2018, the retail price of fuel (kerosene, gasoline (RON 88) and gas oil) is determined by the government by taking into consideration the national policies on energy and state budget, which may be increased or decreased as the case may be. Pursuant to RP 43/2018, the retail price, the base price and market-index price are to be determined by the Minister of Energy and Mineral Resources.

Pursuant to Decision of the Minister of Energy and Mineral Resources No. 1980K/10/MEM/2018 concerning the Market Index Price of Oil Fuel, the Oil Fuel Market Index Price is determined by the Director General of Oil and Gas on behalf of the Minister of Energy and Mineral Resources. The Oil Fuel Market Index Price is determined by the following calculations:

a. for subsidized gasoline, based on the formula of multiplying 98.42% by the published price of MOPS (Mogas 92) on average in the prior three-month;

b. for kerosene, based on the average MOPS publication price of jet kerosene in the prior three-month period;

c. for the retail selling price of a specific type of oil fuel in the form of gas oil, based on the average MOPS publication price of gas oil 0.25% sulfur in the prior three-month period; and

d. for the difference between the market index price of a specific type of oil fuel and general oil fuel in the form of gas oil (as stipulated by the Government) and the market index price of biodiesel (as stipulated by the Government), based on the average MOPS publication price of gas oil 0.25% sulfur in the prior one-month period.

Based on Minister of Energy and Mineral Resources Regulation No. 40 of 2018 on the Sixth Amendment of Regulation No. 39 of 2014 regarding the Calculation of Retail Selling Price of Oil Fuels, the calculation period of the Oil Fuel Market Index Price for gas oil utilizes the average market index price and exchange rate of Rupiah against U.S. dollar with Bank Indonesia's buying rate for each three-month period, which begins on the 25th day of the prior three months and continues up to the

24th day of the latest month. The subsidy reimbursement amount for automotive diesel oil is subject to a fixed amount set by the Government. The subsidy reimbursement formula determined by the Government for kerosene distributed under the PSO mandate is based on MOPS's three-month average price for jet kerosene (which is the Oil Fuel Market Index Price for kerosene), less the regulated retail price.

For LPG in 3kg cylinders, pursuant to Decree of the Minister of Energy and Mineral Resources No. 61K/12/MEM/2019 concerning the Benchmark Price of LPG in 3kg Cylinders for 2019 Annual Budget ("**MEMR Decree 61/2019**"), the subsidy reimbursement formula is based on the benchmark price in 3kg cylinders, which is determined by the market index price of LPG in 3kg cylinders (as stipulated by the Government) applicable in the relevant month, plus distribution (including handling) costs and margins less the regulated retail price. This benchmark price is determined by the following formula: 103.85% market price index of LPG in 3 kg cylinders (as stipulated by the Government) + US$50.11/mt + Rp. 1,879.00/kg.

Pursuant to the Government's 2019 state budget, this benchmark price is used as the basis for calculating the benchmark price for each kilogram of LPG in 3 kg cylinders as it applies to an aggregate volume of 6,978,000 mt of LPG sold by us in Indonesia. This benchmark price may be re-evaluated by the Government at any time with consideration into the realization of factors that may affect the supply and distribution of LPG in 3kg cylinders.

Based on Decree of the Minister of Energy and Mineral Resources No. 62K/10/MEM/2019 concerning the Basic Price Formula of Certain Types of Fuel and Specially Appointed Types of Fuel determines the basic price formula for certain types of fuel, namely kerosene and gas oil, and specially appointed types of fuel, namely gasoline (RON 88). The basic price formula of kerosene is the sum of 102.49% of the market index price of kerosene (as stipulated by the Government) plus Rp. 263 per liter. The basic price formula of gas oil is the sum of 95.00% of the market index price of gas oil (as stipulated by the Government) plus Rp. 802 per liter. The basic price formula of gasoline (RON 88) is the sum of 96.46% of the market index price of gasoline (RON 88) (as stipulated by the Government) plus Rp. 821 per liter. The basic price for kerosene, gas oil and gasoline (RON 88) may be re-evaluated by the Government at any time, depending on the supply and distribution of kerosene, gas oil and gasoline (RON 88).

Online Licensing Procedures for Export and Import

Types of Fuel

The export and import of oil, gas, and other fuels shall not only comply with the Oil and Gas Law of 2001 and Minister of Energy and Mineral Resources regulations, but also the Minister of Trade regulations, which includes, among others, Regulation of the Minister of Trade No. 21 of 2019 on Export and Import Provisions for Oil, Gas, and Other Fuels (which replaced Minister of Trade Regulation No. 3 of 2015 on Export and Import Provisions for Oil, Gas, and Other Fuels) that sets out online licensing procedures for the export and import of fuels, the types of fuel, and the qualified exporting and importing parties. Such parties can export three types of fuel (i.e. oil and gas, state-owned oil and gas, and other fuels) and import two types of fuel (i.e. oil and gas and other fuels).

Exporting and Importing Parties of Fuel

The parties who are permitted to export oil and gas and state-owned oil and gas are "Business Entities" (*Badan Usaha*) engaged in upstream or downstream activities and "Permanent Establishments" (*Bentuk Usaha Tetap*) engaged in upstream activities. Such parties must register as oil

and gas exporters and obtain the Minister of Trade's approval to export. For the export of state-owned oil and gas, the Minister of Trade must also appoint the exporters. The parties who are permitted to export other fuels are "Business Entities" (*Badan Usaha*) engaged in activities involving other fuels. Such parties must register as oil and gas exporters and obtain the Minister of Trade's approval to export.

The parties who are permitted to import oil and gas and other fuels are direct consumers of fuels. For oil and gas, parties who are permitted to import also include "Business Entities" (*Badan Usaha*) engaged in downstream activities. For other fuels, parties who are permitted to import also include "Business Entities" (*Badan Usaha*) engaged in activities involving other fuels. In all cases, these parties must obtain the Minister of Trade's approval to import.

Licensing Procedures for Export and Import of Fuel

The procedures for obtaining the required approval to export fuels start with an electronic application on the Online Single Submission ("OSS") system to obtain a Business Identity Number and business license. Thereafter, applicants submit an electronic application, Business Identity Number and business license through the Ministry of Trade's electronic licensing system, http://inatrade.kemendag.go.id ("INATRADE") to obtain an appointment. The issuance of the appointment takes five business days. The appointment is valid for three years. The applicants then submit their electronic application, export appointment, export realization report (if any), and fuels export recommendation from the Minister of Energy and Mineral Resources through INATRADE. The issuance of approval is in electronic form and takes five business days. Such approval is valid for the same time period as that of the fuels export recommendation.

The procedures for obtaining the required approval to import fuels start with an electronic application at the OSS to obtain a Business Identity Number. Thereafter, the applicants submit an electronic application, Business Identity Number, import realization report (if any), and fuels import recommendation from the Minister of Energy and Mineral Resources officials at the Ministry of Trade. The issuance of approval is in electronic form and takes three business days. The approval is valid for the same time period as that of the fuels import recommendation.

Indonesian Regulation of Offshore Borrowings

Pursuant to Presidential Decree No. 39 of 1991, we are required to obtain prior approval from the PKLN Team to receive offshore borrowings and must submit periodic reports to the PKLN Team. However, the decree does not stipulate either the time frame or the format and the content of the periodic report that must be submitted. Under Presidential Decree No. 59 of 1972, dated October 12, 1972, as partly revoked by the Presidential Decree No. 15 of 1991 on Receipt of Offshore Loans and Issuance of Bank Guarantees for the Acceptance of Offshores Loans by State-Owned Banks and Regional Development Banks Stipulated as Foreign Exchange Banks ("PD 59/1972"), we are required to obtain approval from the Minister of Finance of Indonesia and report the particulars of our offshore commercial borrowings to the Minister of Finance of Indonesia and Bank Indonesia, on the acceptance, implementation, and repayment of principal and interest. In practice, this approval from the Minister of Finance under PD 59/1972 is considered to have been obtained when approval from the PKLN Team is received because the Minister of Finance is a member of the PKLN Team. Minister of Finance Decree No. KEP-261/MK/IV/5/1973 dated May 3, 1973, as amended by the Minister of Finance Decree No. 417/KMK.013/1989 dated May 1, 1989 and partly revoked by the Minister of Finance Decree No. 279/KMK.01/1991 dated March 18, 1991, as the implementing regulation of this PD 59/1972, further sets forth the requirement to submit periodic reports to the Minister of Finance of Indonesia and Bank Indonesia on the effective date of the contract and each subsequent three-month period.

On December 31, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/22/PBI/2014 on the Reporting of Foreign Exchange Activities and of Reporting Application of Prudential Principles in relation to an Offshore Loan Management for Non-Bank Corporation, as partly revoked by the Bank Indonesia Regulation No. 21/2/PBI/2019 on the Reporting of Foreign Exchange Traffic Activities ("PBI 16/22/2014"). Under PBI 16/22/2014, any non-bank entity engaged in activities that cause a movement of (i) financial assets and liabilities between an Indonesian citizen and a non-citizen; or (ii) offshore financial assets and liabilities between Indonesian citizens, must submit a foreign exchange traffic report with respect to any foreign exchange activities to Bank Indonesia. Non-bank entities include state owned entities, regional government-owned enterprises, private enterprises and other entities that are not enterprises, whether in the form of legal entities or non-legal entities established by government or the public. The report must include, among other things, information relating to (i) the trading of goods, services or other transactions between an Indonesian citizen and a non-citizen; (ii) the entity's position with respect to or changes in its offshore financial assets and/or liabilities; and/or (iii) any plans to incur offshore loans and/or its implementation. In addition, PBI 16/22/2014 requires any non-bank entity which applies prudential principles to submit reports which comprise (i) a report on the implementation of prudential principles (ii) a report on the implemental of prudential principles which has complied with an attestation procedure conducted by a public accountant; (iii) notification of compliance of credit ratings; and (iv) financial statements. Bank Indonesia requires reports to be submitted monthly through an online system by the 15th day of the following month. In the event that there is a correction that needs to be made, the correction must be submitted by no later than the 20th day of the reporting month through the online system. The report on the implementation of prudential principles is required to be submitted quarterly or on any other submission deadline set forth in PBI 16/22/2014.

The following Bank Indonesia Circulars further describe the reporting obligations of PBI 16/22/2014:

(a) under Bank Indonesia Circular Letter No. 15/16/DInt dated April 29, 2013 on the Reporting of Foreign Exchange Activities in the form of Offshore Loan Realization and Position, as revoked by the Member of the Board of Governors of Bank Indonesia Regulation No. 21/4/PADG/2019 on the Reporting of the Activities of Foreign Exchange Flow in the Form of Foreign Debts and Risk Participation Transactions ("PADG 21/4"), an Offshore Loan ("OL") is a loan from a resident to a non-resident in foreign currency and/or rupiah, including financing based on sharia principles, and a Risk Participation Transaction ("RPT") is a risk-transfer transaction for an individual credit facility and/or other facilities based on a master risk participation transaction. Banks, non-bank financial institutions and non-financial institution entities must submit reports for all OLs or RPTs regardless of the transaction value. The reports could consist of any one of, or a combination of, the following: (a) a main data report of the OL or RPT, (b) a recapitulation data report of the OL or RPT that includes (i) the withdrawal or payment plan of the OL or RPT, (ii) the realization of withdrawals or payment of the OL or RPT and (iii) the position and change of OL or RPT or (c) a new plan or an amendment of the OL. The OL or RPT main data report, recapitulation data report, new plan or amendment report must be submitted to Bank Indonesia no later than the 15th day of the following month, and a monthly recapitulation data report must be submitted to Bank Indonesia by no later than the 15th day following the signing, issuance or acknowledgement of the OL or RPT;

(b) under PADG-21/4, an Indonesian company that intends to obtain an offshore loan is required to submit a report to Bank Indonesia by no later than March 15 of each year in relation to such loan. In the event there is a change to the company's plan to obtain an offshore loan, any amendment to such report must be submitted to Bank Indonesia by no later than June 15 of the year of such change;

(c) under Bank Indonesia Circular Letter No. 17/26/DSta dated October 15, 2015 on the Reporting of Foreign Exchange Activities Other than Offshore Loan, as revoked by Member of the Board of Governors of Bank Indonesia Regulation No. 21/7/PADG/2019 on the Reporting of Foreign-Exchange Activities by Non-Bank Institutions, which has been in effect since April 12, 2019, the type of reports required are as follows: (a) report of trading transactions involving goods, services and other transactions which are undertaken between residents and non-residents; (b) report of positions and changes of foreign financial assets; (c) report of positions and changes of equity of non-residents and other related liabilities; (d) report of positions and changes of foreign derivative liabilities; (e) report of position of foreign commitments and contingencies; and (f) report of position of securities owned by custodian customers. The non-bank reporter (i.e. non-bank financial institutions, non-financial-institution enterprises and other institutions) is required to submit monthly reports with respect to the foreign exchange activities carried out by the non-bank reporter to Bank Indonesia by no later than the 15th day of the following months; and

(d) under Bank Indonesia Circular Letter No. 17/3/DSta dated March 6, 2015, as amended by Bank Indonesia Circular No. 17/24/DSta dated October 12, 2015 on the Reporting Application of Prudential Principles in relation to an Offshore Loan Management for Non-Bank Corporation, a non-bank corporation must submit reports on the following: (i) a prudential principle report on quarterly basis; (ii) a prudential principle report that has been through attestation procedure no later than the end of June of each year; (iii) information on credit ratings on a monthly basis; and (iv) unaudited quarterly financial statements on a quarterly basis and audited annual financial statements (audited) that must be reported no later than the end of June of each year.

Any delay in submitting a foreign exchange report listed above may result in fines or administrative sanctions.

On May 14, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/10/PBI/2014 as amended by Bank Indonesia Regulation No. 17/23/PBI/2015 dated December 28, 2015 on the Receipt of Foreign Exchange Export Revenue and Withdrawal of Foreign Exchange Offshore Loan ("PBI 16/10/2014"), as implemented by, among others, Bank Indonesia Circular Letter No. 18/5/DSta dated April 6, 2016 on Withdrawal of Foreign Exchange Loan. Under PBI 16/10/2014, an Indonesian debtor is required to withdraw, through foreign exchange banks located in Indonesia, its foreign currency offshore loan (i) obtained under a non-revolving loan agreement that is not used for refinancing; (ii) resulted from the difference between the amount of a refinancing facility and the relevant refinanced existing loan; or (iii) incurred under debt securities (i.e. bonds, medium-term notes, floating rate notes, promissory notes and commercial papers). The Indonesian debtor must report such withdrawal, along with any relevant supporting documents, to Bank Indonesia at the latest on the 15th day of the following month. Late submission may be subject to fines.

PBI 16/10/2014 further stipulates that the accumulated amount of withdrawals for an offshore loan must be equal to the commitment amount of such offshore loan as stated under the relevant offshore loan agreement. If the difference between the accumulated amount of withdrawals and the commitment amount of the offshore loan exceeds Rp. 50 million (or its equivalent in foreign currencies), the Indonesian debtor must provide a written explanation for such difference and sufficient supporting documents to Bank Indonesia before the expiration of the term of the applicable loan. An Indonesian debtor must report the withdrawal of an offshore loan to Bank Indonesia monthly using the recapitulation data report as regulated under PADG 21/4. Failure to provide a written explanation will be deemed as a violation of PBI 16/10/2014. Any violation of PBI 16/10/2014 will subject Indonesian debtors to fines for each non-complying withdrawal.

On December 29, 2014, Bank Indonesia enacted Bank Indonesia Regulation No. 16/21/PBI/2014, as amended by Bank Indonesia Regulation No. 18/4/PBI/2016 dated April 21, 2016 on the Application of Prudential Principles in Management of Offshore Loan of Non-Bank Corporations ("PBI 16/21/2014"). PBI 16/21/2014 requires non-bank corporations that obtain offshore borrowings in foreign currency (other than for trade credit) to maintain the following (the "Prudential Principles"):

(a) foreign currency exchange rate exposure must be hedged with a minimum hedging ratio equal to 25.0 per cent. of the difference between foreign currency assets and foreign currency liabilities;

(b) the ratio of foreign exchange assets to foreign exchange liabilities must be at least 70.0 per cent. and at the end of each quarter, such non-bank corporation must have sufficient foreign currency assets to cover the foreign currency liabilities that will be due to subsequent three months; and

(c) the non-bank corporation must have a credit rating of BB-or higher from a credit rating institution recognized by Bank Indonesia.

PBI 16/21/2014 also requires that such hedging transactions be conducted only with banks in Indonesia with effect from January 2017. In addition, the Issuer is specifically exempted from the minimum credit rating requirement.

The application of Prudential Principles does not apply to offshore loans in foreign currency that are in the form of trade credit, which refers to debt arising from credit that is granted by offshore suppliers over transactions relating to goods and/or services. Exemptions from the requirement to satisfy the minimum credit rating requirement apply for (i) the refinancing of offshore loans in foreign currency; (ii) offshore loans in foreign currency from (a) international bilateral/multilateral institutions; and (b) syndicated loans, with the contribution of international bilateral/multilateral institution exceeding 50.0 per cent., in relation to financing for infrastructure projects; (iii) offshore loans in foreign currency in relation to government (central and regional) infrastructure project; (iv) offshore loans in foreign currency that are guaranteed by international bilateral/multilateral institution; (v) offshore loans in foreign currency that are in the form of trade credit; (vi) offshore loans in foreign currency that are in the form of other loans, which refer to any other loan than loan agreement, debt securities and trade credit that are, among others, payment of insurance claim and unpaid dividend; (vii) offshore loans in foreign currency of finance companies, provided that, when the OJK last determined the soundness level (*tingkat kesehatan*) of the relevant finance company, the finance company had a minimum soundness level and fulfilled the maximum gearing ratio requirement as regulated by OJK; and (viii) offshore loans in foreign currency incurred by Indonesian Export Financing Institution (*Lembaga Pembiayaan Ekspor Indonesia* or "LPEI").

Under PBI 16/21/2014, non-bank corporations are required to report to Bank Indonesia with respect to their implementation of the Prudential Principles. Further, failure to comply on the fulfillment of the Prudential Principles will result in administrative sanctions in the form of a warning letter of which the relevant creditor(s) and certain government institutions will be notified. PBI 16/21/2014 became effective as of January 1, 2015.

Indonesian Regulations on Placement of Foreign Exchange Export Proceeds Deriving From Natural Resources

On January 10, 2019, the Government of Indonesia enacted Government Regulation No. 1 of 2019 on Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or

Management Activities ("GR 1/2019"). Furthermore, on January 18, 2019, Bank Indonesia issued Bank Indonesia Regulation No. 21/3/PBI/2019 on the Receipt of Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or Management Activities ("PBI 21/3/2019").

GR 1/2019 and PBI 21/3/2019 require that export proceeds derived from transactions involving natural resources (*Devisa Hasil Ekspor dari Barang Ekspor Sumber Daya Alam* or "DHE SDA") are (i) deposited in a special account maintained in a Foreign Exchange Bank in Indonesia (as defined in GR 1/2019); and (ii) utilized only for specific purposes, which are for the payments of: (a) export duties and other levies that apply to exports; (b) indebtedness repayments; (c) importation activities; (d) profits or dividends; and/or (e) other purposes as regulated under Article 8 of Law No. 25 of 2007 on Investment. The types of exported goods which fall under the scope of GR 1/2019 and PBI 21/3/2019 are set out and elaborated under Decree of the Minister of Finance No. 1523/KM.4/2019 on the Determination of Natural Resources Export Goods with the Obligation to Insert Foreign Exchange Export Proceeds into the Financial System of Indonesia. The utilization of DHE SDA for the purposes aforementioned must be accompanied by supporting documents. In the event that an exporter makes the payments as described above through an escrow account, such exporter must open an escrow account in a Foreign Exchange Bank in Indonesia (as defined in GR 1/2019), if such account has not existed, or move such account onshore, if such account already exists. Under GR 1/2019, an "escrow account" is defined as an account opened to collect particular funds from which a withdrawal can only be made based on special requirements in accordance with a written agreement between a depositor and a party with an interest over such escrow account. The supervision of such escrow accounts is conducted by the OJK.

On July 1, 2019, the Minister of Finance of Indonesia enacted Regulation of the Minister of Finance Number 98/PMK.04/2019 of 2019 on Tariffs for Administrative Sanctions in the Form of Fines and Procedures for the Imposition, Collection and Payment of Administrative Sanctions in the Form of Fines for Violations of the Provisions on Foreign Exchange Export Proceeds from Natural Resources Business, Processing and/or Management Activities ("PMK 98/2019"). PMK 98/2019 sets out the following administrative sanctions: (i) in the case that an exporter fails to deposit DHE SDA in a special account maintained in a Foreign Exchange Bank in Indonesia (as defined in PMK 98/2019), such an exporter will be imposed with fines in the amount of 0.5% of the value of the DHE SDA which has not been deposited in such special account; (ii) in the case that an Exporter utilizes the DHE SDA deposited in the special account for purposes other than for the payments of: (a) export duties and other levies that apply to exports; (b) loan repayments; (c) importation activities; (d) profits or dividends; and/or (e) other purposes as regulated under Article 8 of Law No. 25 of 2007 on Investment, such an exporter will be imposed with fines in the amount of 0.25% of the value of DHE SDA utilized for such other purposes; and (iii) for an exporter who fails to set up an escrow account (which is an account used to make the payments described previously in point (ii)) or fails to move such account onshore, to a Foreign Exchange Bank in Indonesia (as defined in PMK 98/2019), such an exporter will be imposed with an administrative sanction in the form of a postponement of provision of export customs services.

Indonesian Regulation of Mandatory Use of Rupiah

On June 28, 2011, the Government of Indonesia enacted Law No. 7 of 2011 on Currency (the "Currency Law"). Article 21(1) of the Currency Law requires the use of the Rupiah in each transaction that is intended as a payment, for the settlement of other obligations that must be fulfilled with the use of money and/or in other financial transactions, where the transactions are conducted within Indonesia. Article 23 further prohibits any party from refusing to accept Rupiah as payment or in fulfilment of its obligations and/or for other financial transactions in Indonesia except where there is doubt as to the authenticity of the Rupiah paid. Article 21(2) contains exceptions to the mandatory use of Rupiah for (i) specific transactions in the framework of implementing the state budget, (ii) grants to be given to or received from offshore sources, (iii) international trade transactions, (iv) foreign currency bank deposits and (v) international financing transactions. Article 23(2) contains an additional exemption

from the mandatory use of Rupiah where payments or settlements of obligations in foreign currencies have been agreed in writing. Failure to comply with the above may result in an imprisonment of up to one year and fines of up to Rp. 200 million for any violation and, if the violation is committed by a company, the imprisonment term and fines will be increased by one-third.

Under Bank Indonesia Regulation No. 17/3/PBI/2015 dated March 31, 2015 on the Mandatory Use of Rupiah in the Territory of Indonesia and Bank Indonesia Circular Letter No. 17/11/DKSP dated June 1, 2015 governing the same ("PBI 17/3/2015"), each party is required to use Rupiah for cash and non-cash transactions conducted within the territory of Indonesia, including (i) each transaction which has the purpose of payment; (ii) settlement of other obligations which must be satisfied with money; and/or (iii) other financial transactions (including deposits in Rupiah in any amount and types of denomination from customers to banks). Subject to further requirements under PBI 17/3/2015, the mandatory use of Rupiah does not apply to (i) certain transactions relating to the implementation of state revenue and expenditure, which includes (a) payment of foreign debt; (b) payment of domestic debt in foreign currency; (c) foreign goods expenditure; (d) foreign capital expenditure; (e) state revenue originating from the sales of government bonds in region currency; and (f) other transactions in the context of implementing the state revenue and expenditure budget; (ii) the receipt or provision of grants either from or to an overseas source; (iii) international trade transactions, which includes (a) export and/or import of goods to or from outside Indonesian territory; and (b) activities relating to cross border trade in services; (iv) bank deposits denominated in foreign currencies; (v) international financing transactions; (vi) funds transfers in foreign currencies from individuals in Indonesia to parties who are overseas that are not intended for the payment or settlement of obligations incurred by transactions within the territory of the Republic of Indonesia; and (vii) transactions in foreign currency which are conducted in accordance with applicable laws, including, among others (a) a bank's business activities in foreign currency which is conducted based on applicable laws regarding conventional and sharia banks; (b) securities in foreign currency issued by the Indonesian government in primary or secondary market based on applicable laws; and (c) other transactions in foreign currency conducted based on applicable laws, including the law regarding Bank Indonesia, the law regarding investment and the law regarding LPEI.

PBI 17/3/2015 took effect from March 31, 2015, and the requirement to use Rupiah for non-cash transactions became effective from July 1, 2015. Written agreements which were signed prior to July 1, 2015 that contain provisions for the payment or settlement of obligations in foreign currency for non-cash transactions will remain effective until the expiry of such agreements. However, any extension and/or amendment of such agreements must comply with PBI 17/3/2015. A failure to comply with the mandatory use of Rupiah in cash transactions is subject to criminal sanctions in the form of fines and imprisonment. While a failure to comply with the mandatory use of Rupiah in non-cash transactions is subject to administrative sanctions in the form of (i) written warning; (ii) fines; and/or (iii) prohibition from undertaking payment activities. Bank Indonesia may also recommend to the relevant authority to revoke the business license or stop the business activities of the party which fails to comply with the mandatory use of Rupiah in non-cash transactions.

Under Bank Indonesia's Governor Letter No. 18/3/GBI-DKSP/Srt/B dated February 23, 2016 on the Exemption in the Implementation of the Obligation to Use Rupiah for Category 3 Transactions (the "Bank Indonesia Response Letter"), the Governor of Bank Indonesia has approved some exemptions, which can be described as follows:

a. the exemptions are granted for a maximum period of 10 years starting from 30 days since the date of the Bank Indonesia Response Letter. Furthermore, the Ministry of Energy and Mineral Resources may carry out an evaluation on the effectiveness of the implementation period for such category 3 transactions and coordinate any changes with Bank Indonesia. During this implementation period, Bank Indonesia will also supervise the preparedness of oil and natural gas operators in implementing the provisions on the obligation to use Rupiah, so that such provisions can be implemented effectively;

b. certain transactions relating to the authority of other ministries will be removed from the list of category 3 transactions, namely service or vessel charter transactions to support the upstream as well as downstream oil and gas operations, service or lease of air transportation (charter flight) and freight forwarding service. Furthermore, Bank Indonesia will coordinate with the relevant ministry for such transaction; and

c. the exemptions are granted on seven types of transactions that would qualify as an implementation of state revenues and expenditures budget which are submitted by the Ministry of Energy and Mineral Resources in letter No. 708/06/DMB/2016 dated January 19, 2016 on the Enforcement of Bank Indonesia Regulation No. 17/3/PBI/2015 on the Mandatory Use of Rupiah in the Territory of Indonesia. The seven types of exempted transactions include, among others, oil and gas trading (including LNG regasification activity), natural gas transportation fee, oil transportation by pipe and the procurement of goods or materials from a foreign country (for oil and gas downstream infrastructure).

Under the Bank Indonesia Response Letter, if a currency conversion is required to calculate the price of goods and services in Rupiah that were previously offered in foreign currency, business entities shall use the Jakarta Interbank Spot Dollar Rate, or JISDOR, as reference.

Based on the Bank Indonesia Response Letter, our sale of oil and gas products is included as one of the items that is exempted from the obligation to use and quote in Rupiah.

Indonesian Regulation of Bookkeeping Management in the English Language and US Dollar Currency

Under the Director General of Taxation Regulation No. PER-23/PJ/2015 dated June 1, 2015 on the Procedures for the Application, Notification, Granting, Cancellation as well as Application and Re-Issuance of Permits for Management of Bookkeeping by Using the English Language and US Dollar Currency, the taxpayers who are permitted to bookkeep using the English language and US Dollar currency include:

a. Taxpayers who operate, in the context of foreign capital investment, based on the provisions of the laws and regulations concerning foreign capital investment;

b. Taxpayers who operate, in the context of Contract of Work (*Kontrak Karya*), based on contracts with the Government of the Republic of Indonesia as intended in the provisions of the laws and regulations concerning mining (other than natural oil and gas mining);

c. Taxpaying Contractors of Joint Operation Contract (*Kontrak Kerja Sama*) who operate based on the provisions of laws and regulations concerning natural oil and gas mining;

d. Permanent Establishment (*Badan Usaha Tetap*) as mentioned in Article 2 paragraph (5) of Income Tax Law or as stipulated in the related Double Tax Avoidance Agreement (P3B);

e. Taxpayers who register their share issuance whether partly or entirely in a foreign stock exchange;

f. A Collective Investment Contract (*Kontrak Investasi Kolektif*) which issues mutual funds in US Dollar currency and has obtained an effective statement from the Financial Service Authority or other relevant authorities in accordance with the provisions of laws and regulations concerning capital markets;

g. Taxpayers directly affiliated to a parent company in a foreign country, namely a subsidiary company which is owned and/or controlled by a parent company in a foreign country which has a special relation as intended in Article 18 paragraph (4) sub-paragraphs a and b of Income Tax Law; and

h. Taxpayers who present financial statements in their functional currency by using US Dollar currency in accordance with finance accounting standards applicable in Indonesia.

A taxpayer seeking exemption, as mentioned in letters a, d, e, f, g and h, must obtain a written permit from the Minister of Finance in advance by sending an application to the Head of Regional Office of the Directorate General of Taxation in the working area where the taxpayer is registered by no later than 3 (three) months (a) before the commencement of the accounting year in which the English language or US Dollar currency is used in bookkeeping or (b) starting from the date of establishment for new taxpayers.

Environmental Regulation

Environmental protection in Indonesia is governed by various laws, regulations and decrees. In 2009, the New Environmental Law was issued, replacing the previous regulatory framework. There are some implementing regulations in respect of the New Environmental Law that have been issued, particularly with respect to AMDAL, i.e. (i) State Minister for Environmental Affairs Regulation No. 16 of 2012, which was enacted on October 10, 2012 ("Regulation 16"), which provides guideline on the arrangement for AMDAL documents; and (ii) Regulation No. 27. Regulation No. 27 was enacted on and has been into force as of February 23, 2012 and revokes the previous Government Regulation No. 27 of 1999 on AMDAL. As an implementing regulation in respect of Regulation No. 27, the Minister of Environment and Forestry enacted Minister of Environment and Forestry Regulation No. 23/MENLHK/SETJEN/KUM 1/7/2018 on the Criteria of the Change of Business and/or Activity and Procedures for the Amendment of Environment Permit, which has been in force since July 26, 2018.

Minister of Environment and Forestry Regulation No. 05 of 2012 on Businesses and/or Activity Plans which must obtain AMDAL ("Regulation 05") stipulates, among other matters, that companies whose operations have an environmental or social impact must obtain and maintain an AMDAL document if it meets certain environmental thresholds. The AMDAL document consists of the terms of reference on environmental impact analysis (*Kerangka Acuan Analisis Dampak Lingkungan*), an environmental impact analysis (*Analisis Dampak Lingkungan*), an environmental management plan (*Rencana Pengelolaan Lingkungan*) and an environmental monitoring plan (*Rencana Pemantauan Lingkungan*). If a company has an environmental or social impact but does not reach the threshold where an AMDAL document is required, under Regulation 16, a UKL and a UPL must be prepared by the company. However, if the activity does not need a AMDAL, a UKL or a UPL, then the company must execute a letter to commit to the management and supervision of the environment (*Surat Pernyataan Kesanggupan Pengelolaan dan Pemantauan Lingkungan Hidup*), as required under the New Environmental Law and Regulation 16. Pursuant to the New Environmental Law and Government Regulation No. 27 of 2012 on Environmental License, any company which obtains an AMDAL, a UKL or a UPL must also submit an application to obtain an environmental permit (*Izin Lingkungan*), which is issued by the Minister of Environment and Forestry, Governor, or mayor/regent (in accordance with their respective authorities). The granting of this permit is based on either (i) an environmental feasibility study carried out by an independent third party, which is approved by the AMDAL Assessment Commission (*Komisi Penilai Amdal*), the Minister of Environment and Forestry, the Governor or mayor/regent, as appropriate or (ii) a recommendation in a UKL and UPL issued by the appropriate government or regional government institution responsible for the environmental management and control of the applicable area.

The New Environmental Law stipulates that within two years after its enactment date on October 3, 2009, all businesses that have business licenses, but do not have an AMDAL document or a UKL and a UPL, are obligated to either carry out and complete an environmental audit, if they need an AMDAL, or to prepare an environment management document, if they need a UKL and a UPL. Furthermore, the New Environmental Law obliges businesses to integrate their current environmental management permits (for example, the Toxic and Hazardous Management Permit (*Izin Pengelolaan Limbah B3*), Waste Water Disposal to Sea Permit (*Izin Pembuangan Air Limbah Ke Laut*) and Waste Water Disposal to Water Resources Permit (*Izin Pembuangan Air Limbah Ke Sumber Air*)) issued by either the Minister of Environment and Forestry, governor or mayor/regent, into an environmental permit within a year of the enactment of the New Environmental Law. The environmental permit is required for a business license to be obtained.

Based on the New Environmental Law, remedial and preventative measures and sanctions (such as the obligation to rehabilitate the working areas, the imposition of substantial criminal penalties and fines and the cancellation of approvals) may also be imposed to remedy or prevent pollution caused by the operations of a company. The sanctions range from one to 15 years of imprisonment for company management and/or fines ranging from Rp. 500 million to Rp. 15 billion. A monetary penalty may be imposed in lieu of performance of an obligation to rehabilitate damaged areas.

The New Environmental Law also requires licensing of all waste disposal, storage and handling activities. Waste disposal may only be conducted in specified locations determined by the Minister of Environment and Forestry. Waste water disposal is further regulated by Government Regulation No. 82 of 2001 on Water Quality Management and Water Pollution Control. This regulation requires responsible parties to submit reports regarding their disposal of waste water detailing their compliance with the relevant regulations. Such reports are to be submitted to the relevant mayor or regent, with a copy provided to the Minister of Environment and Forestry, on a quarterly basis.

Regulation No. 27 provides that activities that are subject to AMDAL or UKL and UPL will require an environmental permit. Regulation No. 27 also requires an application for an updated environmental permit to be submitted if there is any, among other things: (a) change of usage of the production machines that affect the environment; (b) increase in production capacity; (c) change in the facilities of the business and/or activity; and (d) change in the operational period of the business and/or activity. Regulation No. 27 further provides that all existing environmental documents/licenses issued prior to Regulation No. 27 remain valid and will be treated as the environmental permit.

With the recently-enacted Indonesian OSS regulation, environmental permits are also delegated to the OSS by virtue of the Government Regulation No. 24 of 2018 regarding Electronically Integrated Business Licensing Services ("GR 24/2018") as further implemented by, among others:

(i) the Minister of Environment and Forestry Regulation No. P.22/MENLHK/SETJEN/KUM.1/7/2018 regarding Norm, Standard, Procedure and Criteria of Electronically Integrated Business Licensing Services in Ministry of Environment and Forestry;

(ii) the Minister of Environment and Forestry Regulation No. P.26/MENLHK/SETJEN/KUM.1/7/2018 regarding the Guidelines on the Preparation and Assessment as well as Examination of Environmental Documents in the Implementation of the OSS System; and

(iii) the Minister of Environment and Forestry Regulation No. 95/MENLHK/SETJEN/KUM.1/11/2018 on the Licensing of Hazardous and Toxic Waste Management Integrated with Environmental Permits through OSS.

Under GR 24/2018, a company will be able to apply for and obtain an environmental permit through the OSS without having a UKL-UPL and AMDAL. However, there is a commitment from the

company to prepare and then submit the UKL-UPL and AMDAL after the environmental permit is issued. Failure to submit the UKL-UPL and AMDAL will result in the revocation of the environmental permit.

The activities of storing and collecting used lubricant oil is further regulated by the Decree of the Head of the Regional Environmental Impact Controlling Agency (*Badan Pengendalian Dampak Lingkungan Daerah*) No. 255/Bapedal/08/1996 on the Procedure on the Storing and Collecting of Used Lubricant Oil, which provides, among other things, that an entity which collects used oil for further use or processing must comply with certain requirements, including obtaining a license; meeting certain specifications with regard to the buildings where used oil is to be stored; setting up a standard procedure for the collection and distribution of used oil; and submitting quarterly periodic reports with regard to these activities.

Other regulations, including Government Regulation No. 101 of 2014 on the Management of Hazardous and Toxic Waste Materials and Government Regulation No. 74 of 2001 on the Management of Hazardous or Toxic Materials relating to the management of certain materials and waste must be also observed. Flammable, poisonous or infectious waste are subject to these regulations unless the company can prove scientifically that it falls outside the categories set forth in such regulation. These regulations require a company that uses such materials or produces waste to obtain a license from the Minister of Environment and Forestry or other environmental governmental institutions in order to store, collect, utilize, process and/or stockpile such waste. If a company violates the regulations relating to such waste, this license may be revoked and the company may be required to cease operations.

Environmental Quality Standards (Baku Mutu Lingkungan)

The second category of environmental obligations of companies relates to the adherence by companies to the various environmental quality standards applicable to their respective industries or activities. These include, among other things, quality standards pertaining to emission, ambient air, nuisance, water, sea water, waste water and any other quality based on the continuing development of science and technology. Article 68 of the New Environmental Law stipulates that all businesses and activities shall adhere to the prevailing regulations regarding quality standards. The national quality standard regarding the environment is governed by Government regulation or ministerial decree. Provincial and municipal governments are also authorized to issue a regional regulation on regional and municipal quality standards. It is therefore important for companies to also review the local regulations on quality standards. In most instances, the quality standards that have been established require companies to report the monitoring of air emissions to the relevant government authority. Technical guidelines have also been provided for implementing the specific standards and their monitoring obligations. Areas of regulation include: (i) quality standards for air emissions from immovable sources; (ii) quality standards for different categories of water; and (iii) quality standards for domestic waste water. One of the relevant regulations that relates to the environmental quality standards in the oil and gas industry is Regulation of the Minister of Environment and Forestry No. 19 of 2010 on Waste Water Quality Standard for the Business and/or Activities of Oil and Gas and Geothermal. Any waste water produced from oil and gas and geothermal activity shall be in compliance with the standards as set out in such regulation.

Sanctions for violating Environmental Quality Standards

Article 98 of the New Environmental Law provides that any deliberate violation of the applicable quality standards of ambient air, water, sea water or other criterion or standards of environmental damage will be subject to criminal sanctions in the form of imprisonment (with a minimum period of three years and a maximum period of ten years) and a fine (with a minimum fine of Rp. 3 billion and a maximum fine of Rp. 10 billion). The amount of sanctions may be increased if the violation results in human injury or death.

Moreover, Article 99 of the New Environmental Law provides that violation of applicable ambient air, water or sea water quality standards by way of omission is subject to criminal sanctions in the form of imprisonment (with a minimum period of one year and a maximum period of three years), and a fine (with minimum value of Rp. 1 billion and a maximum value of Rp. 3 billion). The amount of sanctions may be increased if the violation results in human injury or death.

In addition to the above, a PSC contractor is also subject to other regulations that relate to specific environmental damage, e.g. the BPMIGAS (now SKK Migas) guideline on oil spills (Guidelines No. 005 of 2011). This guideline sets out the obligations of a PSC company to take steps to: (i) prevent oil spills, for example, preparation of equipment and establishment of emergency response training programs; and (ii) respond to oil spills, for example, notification and search and rescue obligations.

In general, an entity held responsible for an oil spill under the prevailing laws and regulations may be subject to three types of liabilities: criminal liability, civil liability and administrative sanctions. The New Environmental Law adopts the strict liability concept, in which a party will be strictly liable for losses resulting from the party's operations if such operation poses significant threats to the environment, uses hazardous and toxic substances and/or generates hazardous and toxic waste. Such strict liability directly and immediately arises upon the occurrence of the environmental pollution and/or damage. SKK Migas has established a specific task force that deals with oil spill occurrences.

A PSC contractor also has a general obligation to preserve the environment under a PSC, and to comply with specific obligations such as abandonment and site restoration obligations under SKK Migas Guidelines No. 40 of 2010, and environmental baseline assessment obligations under SKK Migas Guidelines No. 45 of 2011. Under the PSCs and SKK Migas Guidelines No. 40 of 2010, a PSC contractor must deposit funds into an abandonment and site restoration ("ASR") account once the production stage commences. The ASR account is a joint account of the contractor and SKK Migas. The ASR funds must then be used to comply with the ASR obligations under SKK Migas Guidelines No. 40 of 2010 once the oil and gas activities in the relevant working area have ended. A PSC contractor must comply with its EBA obligations under SKK Migas Guidelines No. 45 of 2011 from the commencement of its activities in its work area. However, for operations under PSCs which were signed before SKK Migas Guidelines No. 45/2011 came into effect, and in relation to which EBA obligations under SKK Migas Guidelines No. 45 of 2011 have not applied, but other environmental assessment obligations (for example, AMDAL obligations) have applied, the PSC contractor must submit the relevant environmental assessment reports to SKK Migas. SKK Migas will then, based on these documents, determine whether the contractor must comply with EBA obligations under SKK Migas Guidelines No. 45 of 2011.

Land Procurement

On December 16, 2011, Parliament passed the Bill on Land Procurement for Public Interest, which came into force on January 14, 2012 as Law No. 2 of 2012 on Land Procurement for Public Interest ("Land Procurement Law"). On August 7, 2012, the implementing regulation of the Land Procurement Law, that is Presidential Regulation No. 71 of 2012 on Land Procurement Process for Public Interest Project ("PR 71/2012") was issued. PR 71/2012 has been amended several times and was last amended by Presidential Regulation No. 148 of 2015 on the Fourth Amendment to PR 71/2012. The Land Procurement Law and PR 71/2012 introduce clear and expedited steps for the procurement of land for public interest. The Land Procurement Law and PR 71/2012 are expected to provide a more effective legal basis for public interest land procurement which, prior to the effectiveness of the Land Procurement Law, was regulated by the Presidential Regulation No. 36 of 2005 on Land Procurement for Public Interest, as amended by Presidential Regulation No. 65 of 2006. Under the Land Procurement Law, the term "public interest" is defined as the interest of the Indonesian people, nation and community that should be manifested by the Government and used optimally for the welfare of all of the people of Indonesia. The Land Procurement Law opens the possibility for state-owned

enterprises which receive a special assignment from the Government to procure land for public interest projects using the procedures provided under the Land Procurement Law.

Under the Land Procurement Law, the Government and the regional government are given the task of ensuring the availability of land required for public interest. The Land Procurement Law also clearly stipulates that a party (the "Entitled Party") who owns or otherwise controls the assessable land procurement objects, which are defined as land, space under and above the land, buildings, plants, any object related to the land or other object ("Land Procurement Objects"), is obliged to release its rights upon such Land Procurement Object for the purpose of land procurement in the public interest, following the provision of fair and reasonable compensation or a legally binding court decision. After such land is released, it becomes the property of the Government, the regional government or a state-owned enterprise, as the case may be.

The Land Procurement Law specifically stipulates that the development projects for public interest are, among others, as follows:

(1) oil, gas and geothermal infrastructure; and

(2) power plant, power transmission, switch yard, power network and distribution.

Initially, an entity that plans to procure land for the public interest must send a notification to the local society and have a public consultation with the parties related to the Land Procurement Objects, including any Entitled Party regarding the proposed development plan, until a consensus is reached. In the event that no consensus can be reached or if there is any objection to the proposed development plan, the Governor will establish a team to examine the reasons for the objections. Based on this, the Governor will decide whether the objections are valid. To the extent that such objections are denied, the Entitled Party may file a legal claim at the State Administrative Court, whose decision can thereafter be subject to final appeal at the Supreme Court. If by virtue of a legally binding court decision, the land has been approved to be procured for the public interest, then the National Land Agency shall appoint an independent appraisal team to determine the compensation value to be paid to the Entitled Party. To challenge the compensation value, the Entitled Party may file a legal claim at a District Court and, if necessary, the decision of the District Court can be filed for final appeal at the Supreme Court.

Maximum Period for Land Acquisition

If there are no objections or appeal requests, the land acquisition process will take around 309 working days. If there is an objection or appeal request, PR 71/2012 sets out a maximum of 455 working days from the date the Governor receives the land acquisition plan documents until the land certification or registration process. The land title itself is extinguished upon the granting of the compensation or the deposit of the compensation in the court or upon completion of land title release. PR 71/2012 also allows the commencement of construction above the procured land after delivery of the procured land to the institution that needs the land.

Land Procurement Stage

Under the Land Procurement Law, land procurement can be divided into four stages: planning, preparation, execution and land delivery. PR 71/2012 specifically delegates the implementation of each stage above to relevant officials:

- Planning — The acquiring entity (for example, the Government institution or state-owned enterprise with special assignment from the Government) will be responsible for preparing the land acquisition plan documents, which must be submitted to the relevant Governor.

- Preparation — Preparation is conducted by the relevant Governor through a preparation team which consists of the relevant mayor or regent, relevant units in the province, the acquiring entity and other relevant institutions. The Governor is allowed to delegate these preparatory tasks and authority to the relevant mayor or regent.

- Execution — The execution of land acquisition falls within the authority of the Head of BPN (National Land Agency), which is implemented through the head of the BPN regional office or the head of the land office, which will act as the head of land acquisition ("Head of Land Acquisition"). The Head of Land Acquisition will form a land acquisition team and lead the negotiation with the affected landowners.

- Delivery — The delivery of the procured land to the acquiring entity will be conducted by the Head of Land Acquisition.

Land "Ownership" Evidence

The Land Procurement Law extends the type of parties who can receive compensation in a land acquisition process by including among others: indigenous people, people who own land that was formerly indigenous land, people who control state land in good faith, owners of buildings, and trustees of waqaf land. PR 71/2012 provides further details of the types of documents and conditions that prove the "ownership" or entitlement over the land. If there is no sufficient land entitlement evidence for people who own land that was formerly indigenous land and people who control state land in good faith, PR 71/2012 allows the person claiming to own the land to provide supporting evidence in the form of written statements from a minimum of two local people that have no family relationship (until the second degree with the person claiming to own the land) confirming that the person is the real owner or is a person who is entitled to the relevant land.

BUSINESS

Unless otherwise stated, the operational summaries and data in this section (including relating to our natural gas transmission and distribution, LNG production, upstream and downstream oil and gas businesses and strategies, proved plus probable oil and gas reserves, exploratory and development wells, oil and gas fields/blocks and upstream oil and gas production and distribution) exclude information concerning and data of PGN, our 56.96% subsidiary acquired in April 2018, which is listed on the Indonesia Stock Exchange under the ticker symbol "PGAS."

You should read the following section in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations — Our Subsidiary, PGN; PGN Acquisition and Related Restatement of Our Financial Statements" and the accompanying notes thereto included elsewhere in this Offering Memorandum.

Overview

We are a fully integrated national oil, gas and geothermal company, wholly owned by the Government and headquartered in Jakarta, Indonesia. We have an operating history of more than 60 years. We were established on December 10, 1957 and became an Indonesian limited liability company in 2003.

We are engaged in a broad spectrum of upstream and downstream oil, gas, geothermal, petrochemical and other energy operations. Our lines of business are organized into upstream and downstream sectors in accordance with Indonesian oil, gas and geothermal regulations. In the upstream sector, we engage in the exploration (the search for oil, gas and geothermal energy), development (the drilling and bringing into production of wells in addition to the discovery wells in a field) and production and supply of crude oil, natural gas and geothermal energy in Indonesia and internationally. In the downstream sector, we carry out refining, marketing, distribution and trading of crude oil, natural gas, refined fuel products and petrochemical and other non-fuel products such as green coke, including products for retail, industrial and aviation uses. We are also mandated by the Government to distribute subsidized fuel, LPG and CNG in Indonesia and to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program and to encourage the use of CNG as an alternative fuel.

As of March 31, 2019, our total net proved oil and gas reserves were an estimated 2,126.3 mmboe and our total net proved plus probable oil and gas reserves were an estimated 2,692.2 mmboe. We have the largest base of oil and gas "commercial reserves" in Indonesia as of March 31, 2019, based on Wood Mackenzie's procedures for reserves categorization. We are also the largest exploration and production player in Indonesia, hold more total blocks and active blocks than any other entity in Indonesia, and have the largest net acreage of all oil and gas companies in Indonesia, according to Wood Mackenzie.

We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 919.2 mboe/d in the three months ended March 31, 2019. We also have significant geothermal resources and an extensive distribution network of gas pipelines. Our geothermal installed capacity was 617 MW as of March 31, 2019. We have a portfolio of six refineries with total refining capacity of 1,031.0 mbbls/d and significant downstream assets and infrastructure, including fuel stations, fuel terminals, LPG filling plants, aviation fuel depots, lube oil blending plants, tankers and CNG refueling stations.

For the years ended December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we had total sales and other operating revenue of US$39,811.9 million, US$46,000.7 million,

US$57,933.6 million and US$12,670.2 million, respectively. For the years ended December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we had profit after the effect of merging entity's income adjustment of US$3,471.2 million, US$2,700.4 million, US$2,716.4 million and US$573.4 million, respectively. For a detailed discussion of our results of operations for these periods, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations."

Business Strengths

The Only Fully Integrated Indonesian Oil and Gas Company

We are the only fully integrated Indonesian oil and gas company, and we have a leading market position in both the Indonesian upstream and downstream markets, providing for full integration across the oil and gas value chain.

Leading upstream oil and gas player in Indonesia. We have the largest base of oil and gas "commercial reserves" in Indonesia, based on Wood Mackenzie's procedures for reserves categorization. As of March 31, 2019, our total net proved oil and gas reserves were an estimated 2,126.3 mmboe and our total net proved plus probable oil and gas reserves were an estimated 2,692.2 mmboe. We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 919.2 mboe/d in the three months ended March 31, 2019. We are also the largest exploration and production player in Indonesia, hold more total blocks and active blocks than any other entity in Indonesia, and have the largest net acreage of all oil and gas companies in Indonesia, according to Wood Mackenzie.

Dominant oil refining, marketing and trading company in Indonesia.

Our comprehensive downstream portfolio significantly complements our upstream strengths. We are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia. Our total production capacity of 1,031.0 mbbls/d in 2018 comprised nearly all of Indonesia's total refining capacity of 1.1 mmbbls/d, based on Wood Mackenzie data. We have extensive downstream infrastructure and an extensive distribution network in Indonesia, which are comprised of pipelines, fuel stations and depots, and shipping vessels. We currently enjoy a 66% market share of the domestic fuel storage market, owning 5.5 billion liters of capacity, and the vast majority of Indonesia's more than 7,000 retail fuel filling stations are Pertamina-branded, according to Wood Mackenzie. We also have a strong presence in the transportation, marketing and distribution markets in Indonesia.

Strategically Positioned in a Fast Growing Domestic Energy Market

Energy demand in Indonesia is projected to increase from 215 million mtoe in 2018 to 255 million mtoe by 2023, representing a CAGR of 3.5%, largely driven by the robust growth of the power sector, according to Wood Mackenzie. Indonesia is currently a net importer of crude oil and refined products, and to meet the escalating demand, based on current domestic output capacity, oil imports are expected to grow significantly. At the same time, the Government has stated its intention to decrease oil imports. We see this as a significant opportunity for growth, which we intend to meet by increasing our oil and gas production capabilities through upstream expansions and acquisitions as well as expanding our refining capacity through upgrades to existing refineries and constructing new refineries.

In particular, gas demand in Indonesia is expected to increase by 0.8 bcfd from 3.3 bcfd in 2018 to 4.1 bcfd in 2023, with around 33% of Indonesia's gas demand being met by LNG by 2023, according to Wood Mackenzie. Gas production is forecast to remain stable through 2019 following a decline in

production in 2018 and is expected to remain at 6.6 bcfd on average until it begins to decline in 2023, according to Wood Mackenzie. West Java and North Sumatra are expected to continue to face supply constraints due to a decline in existing piped gas supply and are expected to increasingly rely on LNG volumes to meet their gas demands, according to Wood Mackenzie. Several gas-fired power plant projects are also expected to be commissioned within the next five years, which we believe will provide strong growth on the demand side. This shortfall can be remedied by pipeline gas and LNG from Sumatra and Kalimantan, areas where we own large acreage and reserves, and where our sizable gas fields in South Sumatra (Pagar Dewa), West Java (Cirebon) and East Java (Cepu) are located.

Indonesia's GDP (at 2010 constant prices) grew at a CAGR of 5.1% between 2012 to 2017 to reach US$1.1 trillion in 2017, according to the World Bank. Indonesia is poised for robust long-term growth with its expanding working age population and relatively competitive cost environment for businesses, according to Wood Mackenzie. Wood Mackenzie expects Indonesia's GDP to grow from US$1,146 billion (at 2010 constant prices) in 2018 to US$1,449 billion by 2023, a CAGR of 4.7%, supported by an increase of 13 million in population size from the population of 267 million in 2018. Currently, a large proportion of Indonesians reside in rural areas and remain unconnected to the power grid, according to Wood Mackenzie. Wood Mackenzie expects that as urbanization continues and power grid connectivity improves, demand for other solid fuels such as non-commercial biomass will decrease from 26% of total energy demand in 2018 to 23% by 2023, while Indonesian coal will grow from 23% of total energy demand in 2018 to 27% in 2023 driven by increasing supply and cost competitiveness.

Based on our presence across Indonesia and our reserves base, we are strategically positioned to meet expected growth in demand.

Sustained Growth from Significant Reserves, Extensive Downstream Infrastructure Network and Proven Operating Track Record

We have the largest base of oil and gas "commercial reserves" in Indonesia, based on Wood Mackenzie's procedures for reserves categorization. We had estimated total net proved oil and gas reserves of 2,126.3 mmboe and estimated total net proved plus probable oil and gas reserves of 2,692.2 mmboe, as of March 31, 2019. We make new reserve discoveries on an ongoing basis which we believe provides strong reserve replacement and that our portfolio not only provides for production longevity but also serves as a solid foundation for production growth. We expect that our production growth potential in Indonesia will be primarily driven by oil development projects in Cepu, Mahakam and Rokan, gas development projects in Mahakam, Sumatra and Java, strategic domestic acquisitions and enhanced oil recovery projects at existing mature oil fields. Internationally, we successfully completed the acquisition of 72.7% of the share capital of and at least 71.4% of the voting rights in Etablissements Maurel et Prom in February 2017 and through our majority shareholding, and we expect to leverage our international operations in 11 countries towards our aim of securing national energy. In addition, we have an estimated 1,365 MW of proved plus probable geothermal reserves as of March 31, 2019, which we expect to drive significant increases in our geothermal production.

We have maintained our leading position in the oil refining, marketing and trading sectors in Indonesia, notwithstanding recent Government initiatives to liberalize the downstream sector, due to our extensive distribution network and supporting infrastructure. We believe that this gives us a substantial advantage over both our domestic and international competitors. For example, we are currently the largest refiner in Southeast Asia by refining capacity and we are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia, according to Wood Mackenzie. We intend to expand our refining design capacity to 2,000 mbbls/d by the end of 2030, a growth of approximately 94.0% from 2018, and to increase the number of fuel stations owned and operated by us.

We have over 60 years of operational history, and our management team and staff have a proven track record and extensive expertise in operational, engineering, technological, commercial, and financial matters. Our long operating history in the region has given us a level of institutional knowledge of and experience in the Indonesian market that is difficult for our competitors, international or domestic, to match. Our management has also gained significant expertise and knowledge through our 47-year history of strategic alliances and partnerships with major international oil and gas companies such as ExxonMobil, Shell and BP.

Robust Financial Profile

We have robust cash generating abilities, which have supported our operating margins and allowed us to achieve strong financial ratios. We have generated Adjusted EBITDA levels of over US$5.0 billion (with Adjusted EBITDA of US$9.2 billion in 2018) in each of the last three years, and our Adjusted EBITDA levels have generally been healthy despite recent volatility in oil and gas prices. Our stable and strong cash flows are based on long-term contracts for the sale of oil, gas and refined products as well as steam and electricity to a diverse group of domestic and multinational customers, including Mitsui Oil and Mitsubishi. For future offtake contracts, we expect to benefit from a strong and growing customer base for production from our substantial Java and Sumatra assets.

Strong Government Support

As a company wholly owned by the Government, we enjoy strong support from the Government, given the importance of our contribution to domestic revenues and our strategic position in the Indonesian oil and gas sector. We are designated as the Government's oil and gas holding company and the Government's 56.96% interest in PGN was transferred to us, making PGN our subsidiary in April 2018. The Government's policy of providing us with a right to request to take over any oil and gas block in Indonesia for which the cooperation contract has expired also allows us to significantly expand our portfolio of domestic upstream assets and to take on attractive new opportunities. We are also entitled to a transition period from oil and gas contractors whose cooperation contracts are scheduled to expire. For example, we were selected as the administrator of the Mahakam Block beginning early 2018 after the existing administrator's contract expired in December 2017. We have also been selected to manage eight oil and gas working areas where the cooperation contracts expired in 2018. We believe that our oil and gas PSCs with the Government in general have more favorable terms than PSCs signed by foreign or private domestic oil and gas companies. Under PEP's PSCs, our share of profits before tax is 67.2%, compared to 12% to 33% for oil and 28% to 37% for gas under a typical PSC. In addition, PHE and local-government enterprises may be nominated by the Government to receive a 10% working interest in PSCs after the first plan of development is approved by the Ministry of Energy and Mineral Resources as PHE is the subsidiary of a state-owned enterprise.

Business Strategy

Our goal is to become one of Asia's leading integrated energy companies that is globally competitive with major international energy companies and international and national oil companies. To achieve these goals, our development strategy is based on four parameters.

Safeguard Indonesia's Energy Future — We intend to meet Indonesia's increasing energy needs by becoming one of Asia's leading integrated energy companies

We aim to secure energy resources for Indonesia, to maintain a leading position in our existing core businesses, and to become a leading national oil company in Asia with a dominant position in Indonesia and a growing international footprint. To achieve this goal, we plan to cultivate a diverse portfolio of energy resources that can meet Indonesia's future energy needs.

In our upstream oil and gas business, we plan to pursue strategic acquisitions, joint ventures, major block development projects and other investments, including with respect to assets that are in production or advanced stages of development, which will expand our oil, gas and geothermal business, in Indonesia and internationally and develop our gas infrastructure in Sumatra and Java. See "Business — Pertamina Upstream Business — Upstream Strategy" and "Business — Pertamina Gas Business." We also aim to maintain our existing leadership in our downstream businesses by diversifying and optimizing our refining capabilities, expanding our retail fuel station network and solidifying our market leadership in fuel, gas and petrochemical products distribution in Indonesia. See "Business — Pertamina Downstream Business — Downstream Strategy."

In the long term, we aim to supplement our existing core businesses and become one of Asia's leading integrated energy companies by expanding our new and renewable energy business into biofuels, biorefineries, photovoltaic power plants, coal conversion and geothermal power strengthening our supply and distribution infrastructure and integrating technology into our business, such as cashless payment systems and digitalized predictive refinery maintenance.

Efficiency — We aim to increase our efficiency and optimize our business operations and technological capabilities

We aim for operational excellence in all of our business activities and intend to consistently achieve above-average efficiency metrics across our operational platform. To achieve this objective, we are focusing on our core businesses and restructuring non-core businesses, streamlining our business processes relating to sales of natural gas and LNG to ensure we obtain optimal pricing, optimizing our upstream assets portfolio and oil recovery activities. We launched the Breakthrough Project ("BTP 2017") in 2017 with initiatives focused on improving efficiencies across all our business lines and improving the efficiency of our refineries. We are focused on employing enhanced oil recovery activities to increase efficiency and production from existing fields and reactivating idle fields. We aim to optimize our current producing assets and improve profitability. For more information, see "— Pertamina Upstream Business — Upstream Strategy" and "— Pertamina Downstream Business — Downstream Strategy." We also have a Research and Technology Centre ("RTC") to serve as an integrated research and development center and to enhance our technological capabilities across our business lines (see "— Research and Development").

Corporate Governance and Culture — We place a high priority on having a strong corporate governance system and a results-driven culture

We place a high priority on corporate governance, professionalism, and transparency, and have developed codes of conduct and corporate policies and procedures that are in line with those of our international and public counterparts. For example, in 2017, Kementerian Badan Usaha Milik Negara (Indonesia's Ministry of State Owned Enterprises) recognized us as the best state-owned enterprise for corporate governance, our President Director Massa Manik was recognized as best chief operating officer in the visionary category and our various subsidiaries won awards in the categories of human resources, transformation, strategy development, financial performance. We were also named by BrandFinance in 2018 as one of the most valuable brands in Indonesia. We also aim to develop a strong, results-driven corporate culture that demands the highest performance by our management and employees alike. One of our key strategies for achieving this end is through our wide range of training and education programs for our employees. To further our efforts, we are also recruiting and developing high quality managerial and technical teams, with an emphasis on the development of leadership skills.

Positioning — We intend to become a model and a benchmark for other regional companies

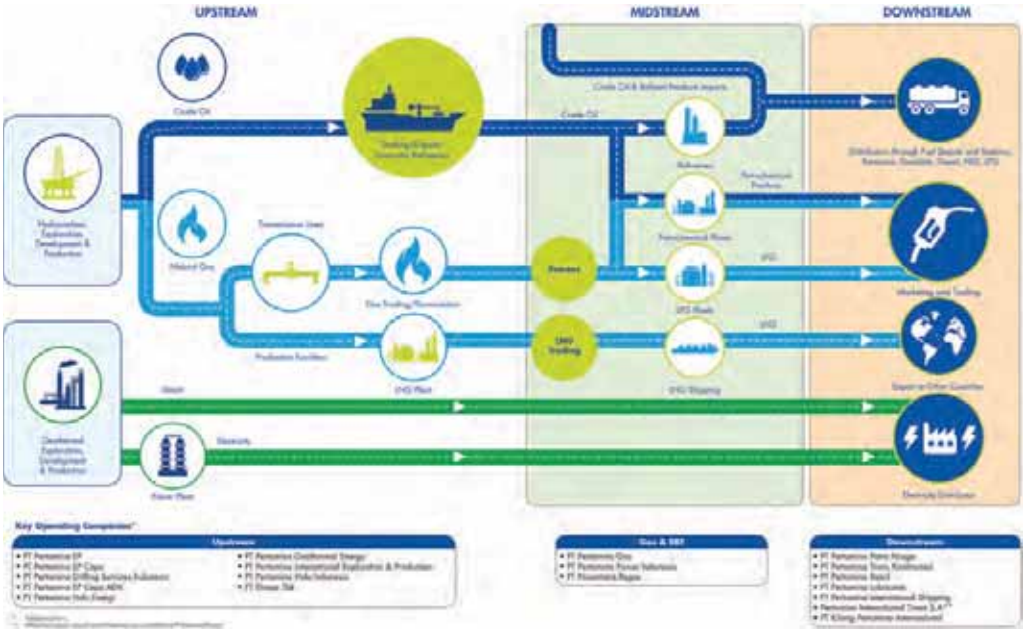
We aim to become the preferred company of our customers, partners and potential employees. We also aim to remain one of the most highly regarded companies in Indonesia, setting a solid benchmark

for Indonesian companies and other energy companies and oil and gas companies in Asia. By implementing international best practices, we believe that we can serve as a standard in terms of capabilities, technology, managerial processes, health, safety and environmental standards and good corporate governance.

Business Flow

The diagrams below illustrate the integration and flow of our business activities from upstream to downstream and across hydrocarbon and geothermal between our upstream, downstream and LNG operations.

PERTAMINA INTEGRATED BUSINESS ACTIVITIES



We explore for, develop and produce crude oil, natural gas and geothermal energy from our upstream operations. The majority of the crude oil we produce is sent to our refineries to produce various refined products, including kerosene, gasoline, diesel and other products, some of which are sold as subsidized fuel under our PSO mandate. These products are sold through our marketing and trading division to industrial and retail customers. We trade or sell our crude oil that is of unsuitable standards for our refineries and import crude oil to meet any shortfall in the quantity or quality of crude oil required by our refineries. Our crude oil and refined products are transported by our shipping division. Our shipping division also transports crude oil, petroleum and non-petroleum products for external customers.

Most of the natural gas we produce is sold directly to our customers using gas pipeline network that we operate and in which we own a significant interest. We also process some of our natural gas to create petrochemical products and LPG, which are sold through our marketing and trading division to retail or industrial customers. In addition to our natural gas production, we also operate facilities that refine LNG and a sea transport network for LNG export to customers in other countries.

The geothermal energy we produce in the form of steam is either sold directly to PLN or private third parties or transmitted to our power plants and used to generate electricity that is then sold to PLN.

Our integrated supply chain division coordinates the supply of feedstock from our production of crude oil and natural gas to our refineries or, in respect of crude oil of unsuitable quality, for export through our trading operations. Our trading operations also coordinate the supply of imported oil and gas to the extent our own production is insufficient to meet demand from our refineries. In addition, our integrated supply chain division coordinates the distribution of our refined products to our marketing and trading division, as well as the import of additional refined products to meet domestic demand. Our integrated supply chain division also gathers and analyzes oil and gas market information on an ongoing basis to support the prudent management of our inventories.

Pertamina Upstream Business

Overview

Our domestic upstream business manages the exploration, development and production of crude oil and natural gas, the transmission of our natural gas, our geothermal operations and our technology services and drilling services. In addition, we manage the exploration, development and production of crude oil and natural gas outside Indonesia. The various subsidiaries and joint ventures described below operate our upstream business and are overseen by our Upstream Directorate, which is a business unit of our Company.

PHE, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas in certain of our partially-owned assets in Indonesia and internationally, which includes 40 exploration and production blocks in Indonesia (consisting of 55 working areas), one block in Malaysia and one block in Vietnam. In 2018, PHE's operations contributed 68,995.8 bbls/d and 793.8 mmcf/d to our total crude oil and natural gas production and in the three months ended March 31, 2019, PHE's operations contributed 80,070.0 bbls/d and 831.2 mmcf/d to our total crude oil and natural gas production. PHE's work areas comprise 24 own-operated fields, eight unitization fields, 18 partnership arrangements (including 9 unconventional oil and gas partnership arrangements), six JOB PSCs, two Pertamina participating interests ("PPIs") and eight unitization agreements.

PEP, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas from our wholly owned oil and gas fields, which is comprised of five assets covering 21 production fields, nine development projects, six unitization fields and 34 partnership contracts across Sumatra, Java, Kalimantan, Sulawesi and Papua (comprising of 7 TACs and 27 JOCs). In total, PEP's production fields have an aggregate working area of 113,629.8 km^2. In 2018, PEP's operations contributed 79,445.4 bbls/d and 1,016.7 mmcf/d to our total crude oil and natural gas production and in the three months ended March 31, 2019, PEP's operations contributed 82,139.4 bbls/d and 968.4 mmcf/d to our total crude oil and natural gas production.

PEPC, our wholly-owned subsidiary, manages the exploration, development and production of crude oil and natural gas in our Cepu block in partnership with subsidiaries of ExxonMobil Corp. and Regional Owned Enterprises. The Cepu block contains one production field and two development projects in an aggregate working area of 919.2 km^2 across Bojonegoro and Tuban in East Java and Blora in Central Java. In 2018, PEPC's operations contributed 93,957.2 bbls/d and 20.2 mmcf/d to our total crude oil and natural gas production and in the three months ended March 31, 2019, PEPC's operations contributed 99,319.3 bbls/d and 25.6 mmcf/d to our total crude oil and natural gas production.

PT Pertamina EP Cepu ADK ("PEPC ADK"), our wholly-owned subsidiary, manages the exploration of crude oil and natural gas in our Alas Dara Kemuning ("ADK") block in Central Java. The ADK field has a working area of approximately 25.0 km^2.

PIEP manages 12 of our international oil and gas operating assets. These assets are in various stages of exploration, development and production, and are located in Algeria, Tanzania and Gabon, Namibia, Nigeria in Africa; Malaysia and Iraq in Asia; Canada, Venezuela and Columbia in the Americas; and France and Italy in Europe. In 2018, PIEP's operations contributed 101,855.2 bbls/d and 298.9 mmcf/d to our total crude oil and natural gas production and in the three months ended March 31, 2019, PIEP's operations contributed 101,738.6 bbls/d and 309.6 mmcf/d to our total crude oil and natural gas production.

PT Pertamina Hulu Indonesia ("PHI"), our wholly-owned subsidiary, is an operation holding company that controls and manages the assets and upstream business operations of Pertamina within the country of the terminated working areas and gas blocks that the Government granted to us, except for terminated work areas previously managed by our affiliates. PHI is the parent of PT Pertamina Hulu Mahakam ("PHM"), which manages the Mahakam Block. In 2018 and in the three months ended March 31, 2019, PHM completed drilling of 59 wells and 26 wells respectively, none of which had entered production. In 2018, PHI's operations contributed 49,143.0 bbls/d and 929.3 mmcf/d to our total crude oil and natural gas production and in the three months ended March 31, 2019, PHI's operations contributed 53,535.5 bbls/d and 775.8 mmcf/d to our total crude oil and natural gas production.

PT Pertamina Geothermal Energy ("PGE"), our wholly-owned subsidiary, manages our geothermal operations. As of March 31, 2019, PGE managed 14 geothermal concessions in Indonesia, covering an area of 23,873.9 km^2. Of our 11 own-operated working areas, six were in the production stage and five were in the exploration or development stage. Of our five working areas jointly operated through JOCs, four were in the production stage and one was in the development stage. We have 1,365 MW of estimated proved and probable reserves in our geothermal concessions. The total installed capacity of PGE-owned operations is 617 MW as of March 31, 2019, consisting of 235 MW in the Kamojang area, 120 MW in the Lahendong and Tompasso area, 220 MW in the Ulubelu area, 12 MW in the Sibayak area and 30 MW in the Karaha Bodas area. In 2018, our geothermal projects produced 31,086 mt of steam or 4,182 GWh in electricity equivalent and in the three months ended March 31, 2019, our geothermal projects produced 7,719.634 mt of steam or 1,021 GWh in electricity equivalent.

PGE continues to undertake geothermal exploration and development activities in all managed areas, which are Seulawah, Sungai Penuh, Hulu Lais, Lumut Balai, Karaha Bodas and Gunung Lawu. See "— Geothermal" for more information on our geothermal operations.

Our upstream business also includes support businesses, including those operated by our wholly-owned subsidiaries, PT Pertamina Drilling Services Indonesia ("PDSI") and PT Elnusa Tbk ("Elnusa"). PDSI provides drilling services to support our oil and gas and geothermal development activities, while Elnusa provides integrated upstream oil and gas services and downstream oil and gas services.

As of March 31, 2019, our estimated total net proved oil and gas reserves were 2,126.3 mmboe, consisting of 1,039.8 mmbbls of oil and 6,295.3 bcf of gas, and our total net proved plus probable oil and gas reserves were 2,692.2 mmboe, consisting of 1,329.0 mmbbls of oil and 7,898.0 bcf of gas. In 2018, we had total average daily net oil and gas production of 921.4 mboe/d, consisting of 416.8 mbbls/d of oil and 2,910.8 mmcf/d of gas and in the three months ended March 31, 2019, we had total average daily net oil and gas production of 919.2 mboe/d, consisting of 416.8 mbbls/d of oil and 2,910.8 mmcf/d of gas.

See "— Reserves" and "— Production" for more information on our oil and gas reserves and production, respectively.

Upstream Strategy

In our upstream business, our strategy is to increase oil, gas and geothermal production and reserves by improving our recovery from existing assets and continuing to pursue strategic acquisitions, joint ventures, major block development projects and other investments that will expand our oil, gas and geothermal businesses in and outside Indonesia. We also aim to grow our upstream business by assuming sole or joint management of domestic oil and gas blocks as existing operating contracts expire. Selected recent examples of implementation of this strategy include the following:

- we acquired 72.7% of the share capital of and at least 71.4% of the voting rights in M&P, a French multinational oil and gas company listed on the Paris Stock Exchange with exploration and production assets in Africa, Europe and Latin America. M&P has total proved and probable oil and gas reserves of 172 mmboe as of December 31, 2018 and had crude oil and natural gas production of 19.7 mbbls/d and 35.4 mmcf/d respectively as of March 31, 2019. The acquisition was completed in February 2017;

- the Government selected PHM, a subsidiary of PHI to become the administrator of the Mahakam Block beginning January 2018 after the existing administrator's contract expired in December 2017. PHI completed 59 new well drillings in 2018. In addition, in 2017, PHE increased its stake in the Offshore North West Java block from 58.3% to 100.0% after the previous administrator's contract expired; and

- the Government selected us to succeed a major international oil and gas producer as the operator of the Rokan Block in Sumatra for 20 years beginning in August 2021. In addition, the Government assigned us to manage eight oil and gas working areas where the cooperation contracts expired in 2018, including the Tuban Block, Ogan Komering Block, Sanga Sanga Block, South East Sumatera Block (SES), Tengah Block, North Sumatra Offshore Block, East Kalimantan Block and Attaka Block.

We may also opportunistically pursue strategic alliances and joint ventures, because we believe that by developing oil and gas assets through strategic alliances with experienced international oil and gas companies, we can supplement and strengthen our technical and management capabilities.

We are focused on employing enhanced oil recovery activities to increase efficiency and production from existing fields and reactivating idle fields. We aim to optimize our current producing assets and improve profitability by increasing production volumes, reducing lifting and production costs, and optimizing operational processes.

In our geothermal operations, we intend to continue to explore for and develop geothermal resources to meet Indonesia's electricity needs and construct integrated geothermal power plants. We increased our installed capacity for power generation to 617 MW in 2018 and intend to increase such capacity to 672 MW in 2019. We are in the process of developing 275 MW of additional production capacity. In 2018, we increased our installed capacity by 30 MW with our Karaha Bodas project commencing operations.

Finally, in 2017, we established our RTC to centralize and integrate our research and development initiatives with the goals of improving production output and efficiency, formulating technological strategies to meet our current and future needs, and enhancing our technological capabilities. In the upstream sector, the RTC focuses on five key areas of research and development, namely exploration, development, production, drilling and geothermal.

Oil and Gas

Our upstream oil and gas operations are conducted through our own operations as well as through joint operating arrangements. We have an interest in 69 blocks worldwide, of which 22 blocks are located in Algeria, Iraq, Malaysia, Tanzania, Gabon, Nigeria, Canada, Colombia, Vietnam, Namibia, France, Italy and Venezuela, and are operated through partners or third parties via joint operating arrangements. The remaining 47 blocks are located in the Sumatra, Java, Kalimantan, Sulawesi and Papua regions of Indonesia. We own-operate 19 of our blocks in Indonesia, while the remaining 28 of our blocks in Indonesia are operated through partners or third parties via joint operating arrangements.

Oil and Gas Reserves

As of March 31, 2019, our total estimated net proved oil and gas reserves were 2,126.3 mmboe, consisting of 1,039.8 mmbbls of oil and 6,295.3 bcf of gas, and our estimated total net proved plus probable oil and gas reserves were 2,692.2 mmboe, consisting of 1,329.0 mmbbls of oil and 7,898.0 bcf of gas.

Except where attributed to Wood Mackenzie, the information on our historical oil and gas reserves in this Offering Memorandum is based on our estimated "net reserves" and, as such, represents our aggregate share of the estimated crude oil and/or natural gas reserves in all blocks or fields or specified areas, attributable to our working interest in such areas, before deducting the share payable to the Government as owner of the reserves pursuant to the terms of the relevant production sharing arrangement, the cost recovery portion and any applicable taxes. "Proved reserves" represent those quantities of crude oil and/or natural gas which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and Government regulations. "Proved developed reserves" are those crude oil and/or natural gas reserves that are expected to be recovered through existing wells with existing equipment and operating methods. "Proved undeveloped reserves" are those reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. "Proved plus probable reserves" are proved reserves plus those reserves that are unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable.

The oil and gas reserves at our blocks and fields have been estimated by us on the basis of our oil and gas resource management system, which contains procedures for classifying and estimating reserves. Until December 31, 2018, the procedures for our oil and gas resource management system and the classifications of our reserves were consistent with PRMS 2007. PRMS 2007 was generally considered the oil and gas industry standard for reserve reporting until it was superseded by PRMS 2018 in 2018. Accordingly, in this Offering Memorandum, except where attributed to Wood Mackenzie, estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. With respect to our reserves managed by PEP, prior to 2017 we had used the SPE 2001 guidelines (which were replaced by PRMS 2007) to determine the procedures for our oil and gas resource management system and the classifications of PEP's reserves. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, in this Offering Memorandum, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018. The characteristics of the estimation uncertainty of natural reservoirs of oil and gas reserve may lead to changes in the estimated reserves due to the additional data obtained by us.

Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

Estimates of reserves are largely dependent on the interpretation of data obtained from drilling, testing and production and may prove to be incorrect over time. Estimates of proved reserves that may be developed and produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs, rather than upon actual production history. Subsequent evaluation of the same reservoirs based upon production history may result in revisions to the estimated proved or proved plus probable reserves. An estimate of reserves is based in part on a field's long-term development plan, and reserves are classified or adjusted and re-classified as contingent where a long-term development plan is not available or up-to-date, for example where a field is under evaluation for future investment and development. The estimation of reserves involves a significant degree of judgment by our management, engineers and technical personnel. Reserves estimates are subject to various uncertainties, including those relating to the physical characteristics of oil and gas fields, as well as changes in oil prices. These uncertainties are difficult to estimate and, as a result, actual production may be materially different from current estimates of reserves. No assurance can be given that the reserves presented in this Offering Memorandum will be recovered at the levels presented. See "Risk Factors — Risks Relating to Our Upstream Operations — Our crude oil, natural gas and geothermal reserve estimates are uncertain and may prove to be incorrect over time or may not accurately reflect actual reserve levels, or even if accurate, technical limitations may prevent us from retrieving these resources."

For instance, the definitions of "proved reserves" and "probable reserves" under our management system vary in certain respects from the definition of "proved oil and gas reserves" used by the SEC, which could cause our reported reserves numbers to be different than if measured based upon the SEC definition.

Rule 4-10(a)(22) of Regulation S-X under the Securities Act defines "proved oil and gas reserves" as follows:

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the rights to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

a. The area of the reservoir considered as proved includes:

   (i) the area identified by drilling and limited by fluid contacts, if any; and

   (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

b. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering,

or performance data and reliable technology establishes a lower contact with reasonable certainty.

c. Where direct observations from well penetrations has defined a highest known oil elevation and the potential exists from an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

d. Reserves which can be produced economically through application of improved recovery techniques (included, but not limited to, fluid injection) are included in the proved classification when:

(i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

e. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Rule 4-10(a)(18) of Regulation S-X under the Securities Act defines "probable reserves" as follows:

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

a. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

b. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

c. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

In addition:

(i) Proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(ii) Where direct observation has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the highest known oil elevation only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

We are not a reporting company in the United States and so we are not required to report our reserves in accordance with SEC definitions. If we were to become a reporting company in the United States, then our proved and proved plus probable reserves would need to be adjusted to comply with the SEC's reporting standards and the adjustments could be material.

PRMS 2007 and 2018 define "proved reserves" as those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. "Probable reserves" are defined as those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than "proved reserves" but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves. In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

We determine the oil and gas reserves for each block and field at the end of each year by taking the previous year's proved plus probable reserve determination (or initial estimate, as the case may be) and adding or subtracting any revisions of previous estimates, subtracting production for the year, then adding extensions and discoveries, acquisitions and divestments and any improved recovery for the year. To determine our total net proved plus probable consolidated oil and gas reserves at the end of each year, we total the oil and gas reserve values for each block as of the end of the year and add any additional reserves attributable to discovery and development and subtract total production for the year. To determine our total net proved consolidated oil and gas reserves at the end of each year, we subtract total probable reserves from the total proved plus probable reserves for the year. The following table sets forth our estimated aggregate net proved and probable reserves as at the dates indicated and the factors which, over the periods indicated, reduced or increased our estimated aggregate net proved and probable reserves.

	Crude Oil (mmbbls)	Natural Gas (bcf)	Combined (mmboe)
2019 (as of March 31, 2019)[1]			
Total net proved plus probable reserves (as of January 1, 2019)	1,362.8	7,825.4	2,713.4
Revisions of previous estimates[2]	(12.8)	(19.5)	(16.1)
Extensions and discoveries[3]	1.9	22.9	5.8
Acquisitions and divestments	11.6	267.8	57.8
Production	(34.4)	(198.6)	(68.7)
Total net proved plus probable reserves (as of March 31, 2019)	1,329.0	7,898.0	2,692.2
Probable reserves	289.2	1,602.7	565.8
Total net proved reserves (as of March 31, 2019)	1,039.8	6,295.3	2,126.3
2018[1]			
Total net proved plus probable reserves (as of January 1, 2018)	1,606.3	8,574.0	3,084.6
Revisions of previous estimates[2]	(279.5)	(1,993.2)	(621.9)
Extensions and discoveries[3]	46.0	164.6	74.4
Acquisitions and divestments	120.2	1,909.1	449.7
Production	(130.3)	(829.2)	(273.4)
Total net proved plus probable reserves (as of December 31, 2018)	**1,362.8**	**7,825.4**	**2,713.4**
Probable reserves	290.7	1,628.0	571.7
Total net proved reserves (as of December 31, 2018)	**1,072.0**	**6,197.4**	**2,141.7**
2017[1]			
Total net proved plus probable reserves (as of January 1, 2017)	1,719.1	9,452.0	3,350.6
Revisions of previous estimates[2]	(287.7)	(962.9)	(455.5)
Extensions and discoveries[3]	157.3	277.6	205.2
Acquisitions and divestments	128.8	431.0	203.2
Production	(111.2)	(623.8)	(218.8)
Total net proved plus probable reserves (as of December 31, 2017)	**1,606.3**	**8,574.0**	**3,084.6**
Probable reserves	356.6	1,655.0	641.6
Total net proved reserves (as of December 31, 2017)	**1,249.7**	**6,919.0**	**2,443.0**
2016[1]			
Total net proved plus probable reserves (as of January 1, 2016)	2,598.6	14,873.7	5,165.8
Revisions of previous estimates[2]	(974.2)	(5,501.0)	(1,923.7)
Extensions and discoveries[3]	192.7	685.9	311.0
Acquisitions and divestments	2.3	—	2.3
Production	(100.2)	(606.5)	(240.9)
Total net proved plus probable reserves (as of December 31, 2016)	**1,719.1**	**9,452.0**	**3,350.6**
Probable reserves	275.0	1,101.5	465.1
Total net proved reserves (as of December 31, 2016)	**1,444.2**	**8,350.5**	**2,885.4**

Notes:

(1) Beginning in 2019, we began classifying and estimating our reserves in a manner consistent with PRMS 2018. Accordingly, estimates of our oil and gas reserves as of March 31, 2019 have been prepared in a manner consistent with PRMS 2018.

Estimates of our oil and gas reserves as of December 31, 2018 and 2017 have been prepared in a manner consistent with PRMS 2007. Estimates of our oil and gas reserves as of December 31, 2016 include estimates of PEP's reserves prepared in a manner consistent with SPE 2001 and have otherwise been prepared in a manner consistent with PRMS 2007. Investors should note that different reserves reporting systems employ different assumptions, and that our methodologies for classifying reserves and our reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC. As a result, because of the impact of such assumptions or differences in the methodologies of resource management systems, identical raw data can produce varying estimates of reserves.

(2) Revisions of previous estimates represent changes over the course of the periods indicated in previous estimates of reserves, either up or down, resulting from new information normally obtained from development drilling and production activities.

(3) Extensions and discoveries represent additions to proved plus probable reserves that result from (i) extensions of previously discovered fields demonstrated to exist subsequent to the original discovery, and (ii) the discovery of reserves in new fields or new reservoirs in old fields, in each case over the course of the periods indicated.

The following table sets forth our estimated net proved and probable reserves by region as of March 31, 2019.

	Crude Oil	Natural Gas	Combined
	(mmbbls)	(bcf)	(mmboe)
Sumatra	192.3	1,994.7	536.6
Java	665.3	3,275.0	1,230.6
East Indonesia (Kalimantan, Sulawesi and Papua)	106.5	1,959.3	444.7
Overseas	398.7	596.4	501.6
Total	**1,362.8**	**7,825.4**	**2,713.4**

As of March 31, 2019, our net proved plus probable reserves have an estimated average life of 9.0 years and our net proved reserves have an estimated average life of 7.0 years. For more information about reserves estimates, see "Presentation of Financial and Other Data — Oil and Gas Reserves."

Oil and Gas Exploration and Development

We are involved in the exploration for and development of oil and gas assets onshore and in shallow-and deep-water environments. Our exploration operations include aerial surveys, geological and geophysical studies (such as seismic surveys), drilling of exploration wells, core testing and well logging. Seismic surveys involve recording and measuring the rate of transmission of shock waves through the earth with a seismograph. Upon striking rock formations, the waves are reflected back to the seismograph. The time lapse is a measure of the depth of the rock formation. The rate at which waves are transmitted varies with the media through which they pass. Seismic surveys can provide either three-dimensional ("3D") or two-dimensional ("2D") results, with 3D surveys generally giving a more detailed picture and 2D surveys being able to cover a wider area. The majority of our seismic surveys are 2D surveys, which we use for exploration and development of our onshore fields. We tend to use 3D surveys for our offshore fields or onshore producing fields.

We analyze the seismic data produced from our exploration activities to understand the underground strata in a given field and to form a view as to whether further exploration activity in that field is warranted. The actual existence of any oil or gas must be confirmed, usually by drilling an exploration well. If the exploration well confirms that oil or gas is present (i.e., is "successful"), we may then drill delineation wells to obtain more detailed data on the reservoir formation. Once the presence of oil or gas in commercially recoverable quantities is proved, or the delineation wells are "successful," development wells may be drilled to prepare for production. A field is considered to be developed when it has a well which is capable of producing oil or gas in paying quantities. We may also restore or increase production in producing wells and abandoned wells (wells which are no longer in use).

Through our exploration operations, we seek to carefully select drilling sites with the highest likelihood of success in order to manage our exploration and development costs. However, the outcomes of exploration activities cannot be predicted with certainty and, as a result, our well drilling success rates have varied in the past. In the years ended December 31, 2016, 2017 and 2018 and the three month period ended March 31, 2019, our success rates for our exploration well drilling were 80.0%, 42.9%, 62.9% and 50.0%, respectively.

The following table sets forth the number of exploratory and development wells completed by us on our properties as at the dates indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Gross exploratory wells drilled[1]	23	20	13	5	4
Crude oil	0	1	2	2	1
Natural gas	15	1	2	1	0
Crude oil and natural gas	7	10	5	0	1
Dry[2]	1	8	4	2	2
Gross development wells drilled[1]	62	91	171	32	59
Crude oil	30	64	74	15	43
Natural gas	8	2	53	7	16
Crude oil and natural gas	24	25	34	10	0
Dry[2]	0	0	0	0	0

Notes:

(1) "Gross" wells refer to all exploratory or development wells, as the case may be, without deducting interests held by others.

(2) "Dry" wells are exploratory or development wells, as the case may be, incapable of producing oil or gas in sufficient quantities to justify completion of exploration as an oil or gas well.

The following table sets forth the number of exploratory and development wells completed by us on our properties by region as at the dates indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Gross exploratory wells drilled[1]	23	20	13	5	4
Productive					
Sumatra	8	4	2	1	1
Java	4	4	4	1	1
East Indonesia (Kalimantan, Sulawesi and Papua)	9	4	3	1	0
Overseas	1	0	0	0	0
Dry[2]					
Sumatra	0	5	2	1	2
Java	1	3	1	1	0
East Indonesia (Kalimantan, Sulawesi and Papua)	0	0	1	0	0
Overseas	0	0	0	0	0
Gross development wells drilled[1]	62	91	171	32	60
Sumatra	13	15	27	5	9
Java	11	16	26	10	9
East Indonesia (Kalimantan, Sulawesi and Papua)	22	43	98	14	35
Overseas	16	17	20	3	7

Notes:

(1) "Gross" wells refer to all exploratory or development wells, as the case may be, without deducting interests held by others.

(2) "Dry" wells are exploratory or development wells, as the case may be, incapable of producing oil or gas in sufficient quantities to justify completion of exploration as an oil or gas well.

As of March 31, 2019, we had 34,293 km^2 of undeveloped acreage for future exploration and development.

Exploration and development plans. Currently, we have plans to continue exploration efforts in all of our existing blocks using 2D and 3D seismic surveys and drilling exploration wells and delineation wells in our existing blocks.

We have set a target to drill more than 319 development wells by the end of 2019. Our basic strategy of field development is to monetize all oil and gas discoveries for early production. We have a similar approach to our construction of facilities by maximizing the usage of readily available materials, equipment and personnel and using simple designs for our production operations.

Through PHE, we have entered into PSCs for the exploration and development of coal bed methane in 14 working areas in Sumatera and Kalimantan working area with contract terms of 30 years having end dates beyond 2038. PHE directly operates six of these working areas, with the remaining eight operated by third parties. We also entered into a PSC with SKK MIGAS in May 2013, in which we were granted a 100% participating interest in the Non-Conventional Oil and Gas Block North Sumatera for the exploration and production of shale gas over a period of 30 years. Finally, we have conducted studies, including field studies in Bengkulu, Palembang, Bangka Belitung and Salawati, to broaden our exploration activities beyond the earth's tertiary layer to its pre-tertiary layers.

Drilling operations. Our oil and gas and geothermal exploration and development activities require extensive drilling expertise and support. Our wholly owned subsidiaries, PDSI and Elnusa, provide land drilling services, integrated drilling project management and drilling tools to support our onshore drilling activities. In total, we have a fleet of 42 onshore drilling rigs located across Indonesia. Through PDSI and Elnusa, we are able to provide most of the drilling services needed for our onshore exploration and development activities. The remainder are provided by third-party contractors. Our aim is to expand our drilling operations to support third party and offshore operations in the future. We are currently in the process of investing in direct current electric drills, which are more efficient and environmentally friendly than mechanical drill.

Oil recovery activities. We conduct secondary recovery activities to enhance our existing oil reserves. Our principal method is water flooding, in which water is injected into a reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. We use our own technology and operators to conduct the water flooding. We also reactivate idle fields, if feasible, to further enhance our existing oil reserves.

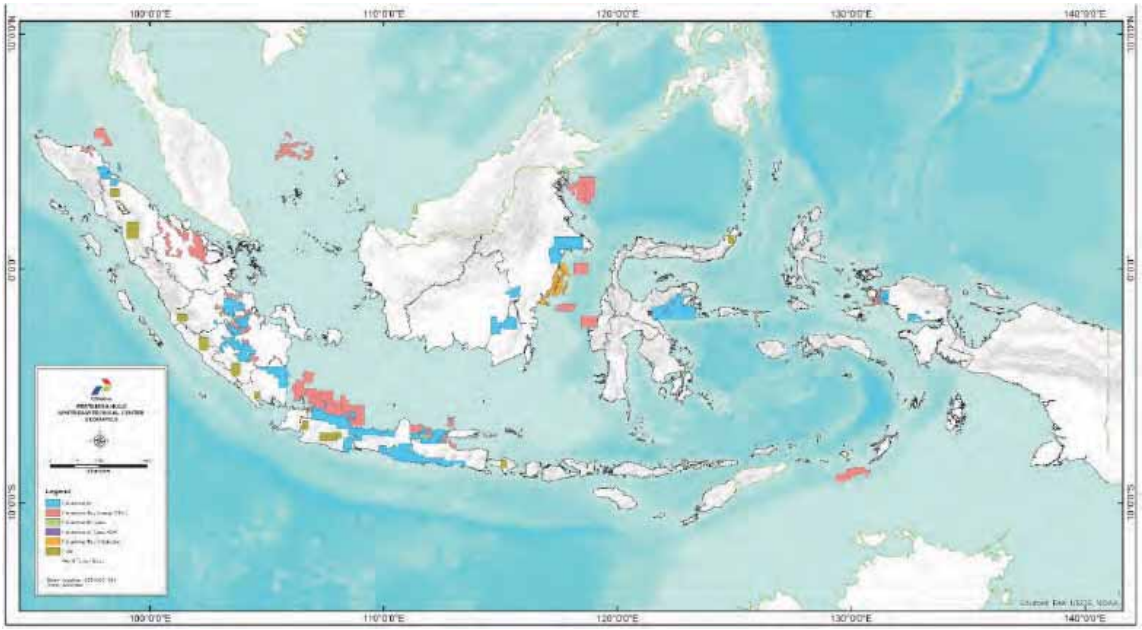
We are currently exploring the use of carbon dioxide and chemical injections as alternative methods of tertiary recovery to further enhance our existing oil reserves.

Description of material Indonesian properties. Our oil and gas activities in Indonesia are primarily carried out through various production sharing arrangements and cooperation contracts covering 56 blocks, including PSCs, TACs/OCs, JOBs, IPs, PPIs and unitization with various partners for coal bed methane. Of our blocks in Indonesia, we have more than 2,100 wells currently in commercial production. See "Indonesian Regulatory Framework" for a discussion of certain of the terms and conditions of the production sharing arrangements and cooperation contracts under Indonesian law.

Other than our PEP block, our top four producing blocks are Cepu (managed by ExxonMobil Cepu Ltd.), Pertamina Hulu Mahakam (managed by Pertamina Hulu Mahakam), Offshore Northwest Java

(managed by Pertamina Hulu Energi Offshore North West Java ("PHE ONWJ")), and West Madura Offshore (managed by Pertamina Hulu Energi West Madura Offshore ("PHE WMO")), based on combined oil and gas production in 2018. The top three fields with the largest oil reserves are the Banyu Urip field in the Cepu block and the Sukowati and Prabumulih fields in the PEP block. The three fields with the largest gas reserves are the Subang field in the PEP block, Senoro field in the PHE block and Pendopo field in the PEP block.

The following map illustrates our domestic upstream operations as of March 31, 2019.



The following tables set forth certain information regarding our material upstream operations as of March 31, 2019, other than PEPC ADK's Alas Dara Kemuning block, which is in the exploration stage.

PHE

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Corridor	10.0	December 20, 2003 to December 20, 2023	Conoco Philips (Grissik) LTD (54%) (operator), Talisman (36%)	1.3	219.2	703.988	102.05
CPP	50.0	August 9, 2002 to August 8, 2022	PT Bumi Siak Pusako (50.0%) (operator BOB Pertamina Bumi Siak Pusako)	10.8	—	5,434.26	—
Jabung	14.2	February 27,1993 to February 26, 2023	Petrochina (Jabung) LTD (42.9%) (operator), Petronas (42.9%)	9.6	80.3	2,140.79	39.70
Jambi Merang	100.0	May 31, 2018 to May 31, 2038	Talisman (25.0%), Pacific Oil & Gas (25.0%)	0.1	2.2	2,177.76	43.42
Offshore North West Java	90.0	January 19, 2017 to January 18, 2037	PT MUJ-BUMD (10.0%)	327.4	952.3	26,416.19	99.72
Offshore South East Sumatera	100.0	September 6, 2018 to September 5, 2038		46.9	119.7	6,425.7	41.68
Ogan Komering	100.0	May 19, 2018 to May 18, 2038		2.9	8.8	1,535.05	5.80

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Senoro Toili	50.0	December 4, 1997 to December 3, 2027	PT Medco E&P Tomori Sulawesi (30.0%), Tomori E&P Ltd. (20.0%)	9.2	548.6	3,840.75	154.16
Tuban	100.0	May 19, 2018 to May 18, 2038		1.7	3.1	1,389.12	5.80
West Madura Offshore	80.0	May 7, 2011 to May 6, 2031	Kodeco Energy Co LTD (20.0%)	20.6	165.6	4,566.64	106.25
Siak	100.0	May 28, 2014 to May 27, 2034	—	5.2	0	1,817.91	0
North Sumatera B	100.0	October 4, 1998 to October 4, 2018 (extended until October 4, 2019)	—	1.8	29.2	1,762.53	65.67
North Sumatera Offshore	100.0	October 17, 2018 to October 16, 2038	—	0.3	100.2	104.42	90.2
Raja Tempirai	50.0	July 6, 1989 to July 5, 2019	Golden Spike Energy Indonesia Ltd (50%)	0.1	0.0	277.98	0.18
Simenggaris	37.5	February 24, 1998 to February 23, 2028	Medco Simenggaris Pty Ltd (41.5%), Salamander Energy Ltd (21%)	0	8.4	0	0.03
Kampar	100.0	January 1, 2016 to December 31, 2036	—	2.6	0	1,046.72	0
Kakap	10.0	March 22, 2005 to March 21, 2028	Star Energy (Kakap) Ltd (56.25%), Premier Oil Kakap BV (18.75%), and Singapore Petroleum Co. Ltd (15%)	1.0	17.3	233.52	4.30
Blok A (Natuna Sea)	11.5	October 16, 2009 to October 15, 2029	Premier Oil Natuna Sea Ltd (28.7%), Kufpec Indonesia (Natuna) B.V. (33.33%) and Natuna I B.V. (15%)	1.1	79.0	135.59	27.35
Randugunting	100.0	August 9, 2007 to August 8, 2037	—	**	**	**	**
Abar	100.0	May 22, 2015 to May 21, 2045	—	**	**	**	**
Anggursi	100.0	May 22, 2015 to May 21, 2045	—	**	**	**	**
Nunukan	64.5	December 12, 2004 to December 11, 2034	Videocon Indonesia Nunukan (17.8%), BPRL Ventures Indonesia B. V. (17.8%)	0	0	0	0
Ambalat	33.75	September 27, 1999 to September 26, 2029	Eni Ambalat Ltd (66.25%)	**	**	**	**
East Ambalat	100.0	May 24, 2016 to May 23, 2036	—	**	**	**	**
Makassar Strait	10.0	January 26, 1990 to January 25, 2020	Chevron Makassar Strait (72.0%), Sinopec Tiptop (18.0%)	**	**	**	**
Maratua	100.0	February 18, 2018 to February 17, 2038	—	**	**	**	**
Bukat	33.75	February 24, 1998 to February 23, 2028	Eni Bukat Ltd (66.25%)	**	**	**	**
East Sepinggan	15.0	July 20, 2012 to July 20, 2042	Eni East Sepinggan Ltd (85%)	**	**	**	**
Babar Selaru	15.0	November 21, 2011 to November 20, 2041	Inpex Babar Selaru (85%)	**	**	**	**
Tanjung Enim	27.5	August 4, 2009 to August 3, 2039	PT Bukit Asam Metana Enim (27.5%), Dart Energy (Tanjung Enim) Pte Ltd (45%)	**	**	**	**

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Muara Enim	60.0	November 30, 2009 to November 29, 2039	PT Trisula CBM Energy (40%)	**	**	**	**
Muara Enim I	65.0	December 3, 2010 to December 2, 2040	PT Indo Gas Methan (35%)	**	**	**	**
Muara Enim II	40.0	April 1, 2011 to March 31, 2041	PT Metana Enim Energi (30%) and Indo CBM Sumbagsel 2 Pte Ltd (30%)	**	**	**	**
Muara Enim III	40.0	April 1, 2011 to March 31, 2041	PT Metana Enim Energi (30%) and Indo CBM Sumbagsel 2 Pte Ltd (30%)	**	**	**	**
Sangatta I	52.0	November 13, 2008 to November 12, 2038	Sangatta West CBM Inc (48%)	**	**	**	**
Sangatta II	40.0	May 5, 2009 to May 4, 2039	PT Visi Multi Artha (60%)	**	**	**	**
MNK Sumbagut	100.0	May 15, 2013 to May 14, 2043	—	**	**	**	**
MNK Sakakemang	50.0	May 22, 2015 to May 21, 2045	Bukit Energy Resources Sakakemang Deep Pte Ltd (50%)	**	**	**	**

Note:

** Not applicable; the block is in the development or exploration stage.

From April 2020 until April 2040, we will have a 30.0% working interest in the Salawati block, with the other 70.0% being held by Petrogas Island Ltd. We previously held a 50.0% working in interest in the Salawati block and, as of March 31, 2019, its estimated net proved and probable reserves were 4.0 mmbbls and 2.0 bcf for oil and gas, respectively, and the average net annual production is 805.93 bbls/d and 1.88 mmcf/d for oil and gas, respectively.

From October 2020 until October 2040, we will have a 30.0% working interest in the Salawati Basin block, with the other 70.0% being held by Petrogas Basin Ltd. We previously held a 10.0% working interest in the Salawati Basin block but as the block is in the development or exploration stage, no data for estimated net proved and probable reserves or average net annual production is currently available to us.

PT Pertamina Hulu Rokan

From August 2021 until August 2041, we will have a 100% working interest in the Rokan block which is currently managed, and until August 2021 will continue to be managed, by PT Chevron Pacific Indonesia (previously PT Caltex Pacific Indonesia). As we will not take over the working interest of the Rokan block until August 2021, no data for estimated net proved and probable reserves or average net annual production is currently available to us.

PEP

Region	Working Interest (%)	Contract Term	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
			Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Sumatra	100.0	September 2005 to September 2035	155.5	1,458.5	36,103.5	529.8
Java	100.0	September 2005 to September 2035	88.3	1,226.2	20,039.2	373.5
Eastern Indonesia (Kalimantan, Sulawesi and Papua)	100.0	September 2005 to September 2035	47.3	486.3	20,541.9	112.2

PEPC

Block	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Cepu	45.0	September 17, 2005 to September 16, 2035	Ampolex (Cepu) Pte Ltd. (24.5%), ExxonMobil Cepu Limited (20.5%) (operator), PT Sarana Patra Hulu Cepu (1.1%), PT Petrogas Jatim Utama Cendana (2.2%), PT Asri Dharma Sejahtera (4.5%), PT Blora Patragas Hulu (2.2%)	180.4	808.2	94,718.3	19.3

PHI

Block/Field	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Mahakam Block	100.0[(1)]	January 1, 2018 to December 31 2037	Pertamina Hulu Mahakam	27.9	790.3	42,050.0	879.2
Sanga Sanga Block	100.0	August 8, 2018 to August 7, 2038	Pertamina Hulu Sanga Sanga	8.5	70.4	3,668.0	33.8
East Kalimantan and Attaka Block	100.0	October 25, 2018 to October 24, 2038	Pertamina Hulu Attaka	8.7	47.2	3,425.0	16.2

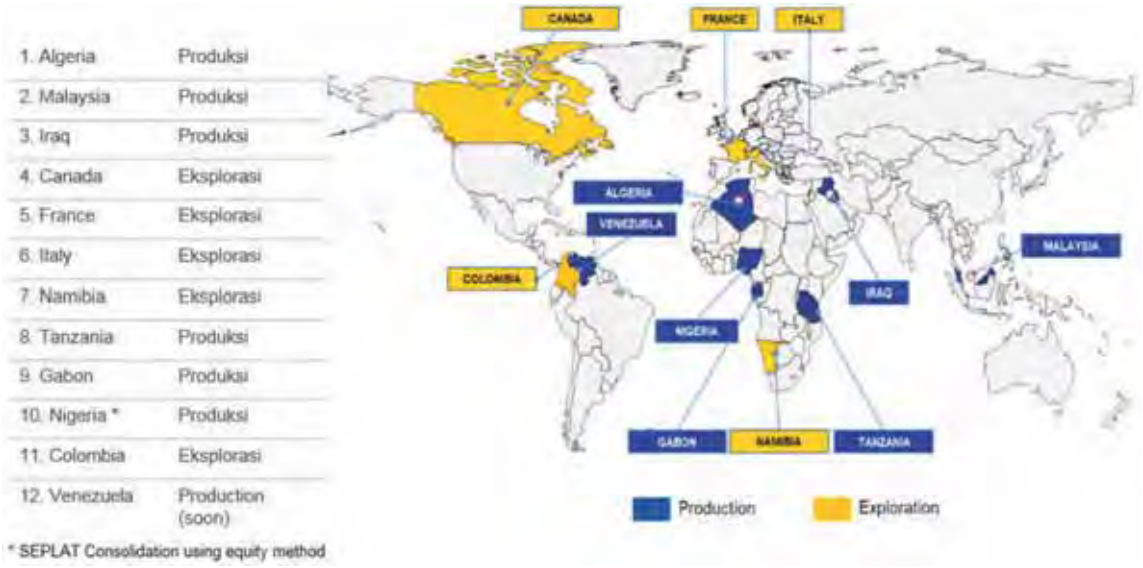
Note:

(1) Subject to receipt of approval from the Minister of Energy and Mineral Resources, 10.0% of this working interest will be transferred to PT Migas Mandiri Pratama Kutai Mahakam (PT MMPKM).

Description of International Oil and Gas Properties

Our oil and gas activities outside of Indonesia are primarily operated by our joint venture partners. Of our 22 international assets, 6 are currently in commercial production.

The following map illustrates our international upstream operations as of March 31, 2019.



The following tables set forth certain information regarding our upstream international operations as of March 31, 2019, excluding blocks held by M&P for which no information is available.

				Estimated Net Proved and Probable Reserves		Average Net Annual Production	
Block/Field	**Working Interest (%)**	**Contract Term**	**Partners**	**Oil (mmbbls)**	**Gas (bcf)**	**Oil (bbls/d)**	**Gas (mmcf/d)**
Algeria							
Block 405a, Menzel Lejmat North (MLN) Field	65.0	December 20, 2000 to December 19, 2025	Talisman (Algeria) B.V. (35.0%)	38.7	0	10,683.2	132.9
Block 405a, El Merk (EMK) Field	16.9	July 2005 to July 2030	Talisman (Algeria) B.V. (9.1%), Sonatrach (37.7%), Anadarko Algeria Company LLC (18.1%), Eni Oil Algeria Ltd. (9.1%), Maersk Olie Algeriet AS (9.1%)	26.7	0	8,870.9	30.2
Block 405a, Ourhoud Field	3.7	December 6, 1997 to December 5, 2022	Talisman (Algeria) B.V (1.9%), Sonatrach (37.1%), Anadarko Algeria Company LLC (10.2%), Eni (5.08%), Maersk Olie Algeriet AS (5.08%), Compania Española Petroleos SA (37.1%)	3.5	0	3,198.5	4.9
Gabon							
Ezanga	80.0	January 1, 2014 to December 31, 2034	The Gabonese Republic (12.5%), Tullow (7.5%)	133.0	*	16,273.0	*
Iraq							
Block West Qurna I	10.0	January 25, 2010 to January 24, 2045	ExxonMobil Iraq Limited (32.7%), Shell Iraq B.V. (19.6%), PetroChina International Iraq FZE (32.7%), Oil Exploration Company of the Iraqi Ministry of Oil (5.0%)	143.0	0	45,470.0	*
Malaysia							
Block H, Sabah	24.0	March 19, 2007 to March 18, 2045	Murphy Oil Co. Ltd. (56.0%), Petronas (20%)	0.1	207.9	**	**
Block K, Sabah	24.0	January 27, 1999 to January 26, 2037	Murphy Oil Co. Ltd. (56.0%), Petronas (20%)	27.9	19.3	9,569.5	15.8

Block/Field	Working Interest (%)	Contract Term	Partners	Estimated Net Proved and Probable Reserves		Average Net Annual Production	
				Oil (mmbbls)	Gas (bcf)	Oil (bbls/d)	Gas (mmcf/d)
Block SK 305, Sarawak	30.0	June 16, 2003 to June 15, 2032	Petronas Carigali Sdn. Bhd. (40.0%) PetroVietnam (30.0%)	*	*	**	**
Block SK309, Sarawak	25.5	January 27, 1999 to January 26, 2028	Murphy Oil (59.5%), Petronas (15%)	3.5	77.4	2,398.8	54.6
Block SK311, Sarawak	25.5	January 27, 1999 to January 26, 2028	Murphy Oil (59.5%), Petronas (15%)	10.5	41.0	4,678.6	20.5
Block SK314A, Sarawak	25.5	May 7, 2013 to May 6, 2040	Murphy Oil (59.5%), Petronas (15%)	*	*	9,569.5	15.8
Vietnam							
Vietnam Blok 10 and 11.1	10.0	January 8, 2002 to January 7, 2032	Petrovietnam Exploration Production Corporation Ltd (40%), Petronas Carigali Sdn. Bhd. (40%) Quad Energy S.A. (10%)	*	*	*	*
Colombia							
Cor 15	20.0	*	*	*	*	*	*
Namibia							
Petroleum Exploration License-44	42.5	*	Azinam (42.5), National Petroleum Corporation of Namibia (8%), Livingstone Mining Resource Development (4%), Frontier Mineral Resources (3%)	*	*	*	*
Nigeria							
OML 4, 38, 41	45.0	June 1989 to October 2038	Nigerian Petroleum Development Company Ltd (55.0%)	*	*	*	*
OPL 283	40.0	October 2009 to October 2028	Pillar Oil (60.0%)	*	*	*	*
OML 53	40.0	June 1997 to June 2027	National Nigerian Petroleum Corporation (60.0%)	*	*	*	*
OML 55	22.0	June 1997 to June 2027	Belema Oil (*), National Nigerian Petroleum Corporation (*)	*	*	*	*
Tanzania							
Mnazi Bay	48.1	October 26, 2006 to October 25, 2031	Wentworth (31.9%), TPDC (20.0%)	*	231.6	*	40.0
Canada							
Alberta	25.0	*	*	*	*	*	*
Italy							
Fiume Tellaro	100.0	*	*	*	*	*	*
Venezuela							
Urdaneta West Field	40.0	2006 to 2026	Petróleos de Venezuela, S.A. (60.0%)	*	*	*	*

Notes:

* Information not available.

** Not applicable; the block is in the development or exploration stage.

Upstream Oil and Gas Production

We are the largest oil and gas producer in Indonesia in terms of net working interest production, according to Wood Mackenzie, with 661 mboe/d in 2018. Our total average daily oil and gas production was 921.4 mboe/d in 2018 and 919.2 mboe/d in the three months ended March 31, 2019.

The information on our oil and gas production presented and referred to as "production" in this Offering Memorandum is our "net production" and represents our share of the oil and/or gas production from a block or field, attributable to our working interest before deducting the share payable to the Government pursuant to the terms of the relevant production sharing arrangement or cooperation contract and the cost recovery and any applicable taxes. Our lifting costs include our costs of acquisition of our partners' share of crude oil or gas under the relevant production sharing arrangements or cooperation contract which is based on the global price of crude oil and has risen over the past three years. The following table sets forth our average oil and gas production on a daily basis, our average realized sales prices per barrel of crude oil, average realized sales prices per thousand cubic feet of natural gas, lifting costs per barrel of crude oil and lifting costs per thousand cubic feet of natural gas produced for the period, indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Sumatra					
Crude oil (mbbls/d)	57.0	54.3	67.2	52.6	54.4
Natural gas (mmcf/d)	864.2	883.3	922.8	898.5	844.0
Total (mboe/d)	**206.2**	**206.8**	**226.5**	**207.7**	**200.1**
Java					
Crude oil (mbbls/d)	140.5	159.8	146.7	154.0	181.9
Natural gas (mmcf/d)	644.1	616.1	628.1	629.4	686.8
Total (mboe/d)	**251.7**	**266.2**	**175.6**	**262.7**	**300.4**
East Indonesia (Kalimantan, Sulewasi and Papua)					
Crude oil (mbbls/d)	25.7	23.9	28.5	74.3	78.8
Natural gas (mmcf/d)	231.6	260.7	1,209.1	1,291.4	1,070.3
Total (mboe/d)	**65.7**	**68.9**	**237.2**	**297.2**	**263.5**
International					
Crude oil (mbbls/d)	88.3	103.7	101.9	105.0	101.7
Natural gas (mmcf/d)	223.1	275.2	298.9	295.3	309.6
Total (mboe/d)	**126.8**	**151.2**	**153.5**	**155.9**	**155.2**
Total					
Crude oil (mbbls/d)	311.6	341.7	393.4	385.9	416.8
Natural gas (mmcf/d)	1,962.9	2,035.4	3,058.9	3,114.6	2,910.8
Total (mboe/d)	**650.4**	**693.0**	**921.4**	**944.5**	**919.2**
Average realized sales price of oil (US$ per bbl)	39.8	51.2	70.6	63.7	63.1
Average realized sales price of gas (US$ per mcf)	6.0	5.8	6.31	4.4	4.8
Lifting costs of oil (US$ per bbl)	17.9	20.7	23.2	22.1	20.9
Lifting costs of gas (US$ per mcf)	2.2	1.9	2.3	2.9	3.3
Lifting costs of oil and gas (US$ per boe)	15.3	15.8	18.4	19.0	20.6

Upstream Oil and Gas Sales and Distribution

Crude Oil

Our policy is to maximize usage of our crude oil production as feedstock in our refineries. In 2016, 2017 and 2018 and in the three months ended March 31, 2019, 85.8%, 80.8%, 80.5% and 78.2% of the crude oil we produced was used as feedstock in our refineries, respectively. A portion of the crude oil which we produce is not of suitable quality for our refineries and we trade such crude oil in exchange for crude oil of suitable quality or sell it on the spot market or through a term contract. For each of the years ended December 31, 2016, 2017 and 2018 and the three-month period ended

March 31, 2019, 14.2%, 19.2%, 19.5% and 21.8%, respectively, of our crude oil production was either traded or sold to third parties.

Gas

We sell the natural gas we produce under contractual arrangements which may be for periods of five to ten years or more than ten years. These arrangements typically take the form of binding memorandums of understanding or gas sales agreements that are entered into directly with the customers. The binding memorandums of understanding set forth the general terms of understanding pending definitive gas sales agreements to be agreed to between the parties. Our current customers for gas include power plants, industrial companies, refineries and fertilizer companies. We also occasionally enter into non-binding memorandums of understanding with potential customers prior to negotiating and entering into gas sales.

The following table sets forth our material gas sales agreements.

Block	Counterparty	Term	Pricing (US$/mmbtu)	Total Quantity (bbtu)	Daily Quantity (bbtu/d)	Take-or-Pay %
Sumatra						
Jambi Merang	PLN	12 years from 2007	6.26[1]	178.4	65	75
PEP[2]	Asrigita Prasarana	20 years from 2004	6.14	188,940	28.9	70

Notes:

(1) For the first 12 months and further escalated by 3% for every 12 months thereafter.

(2) PEP has also entered into a contract with PGN South Sumatra-West Java for a period of 20 years from 2006 to provide 1,006,050,003,000 bbbtu of natural gas at a price of US$5.33/mmbtu.

Under our gas sales agreements, we are obligated to supply gas for the contracted quantity while offtakers are required to accept an agreed portion of the gas on a "take or pay" basis. This arrangement reduces our production risk exposure, by ensuring that a certain fixed portion of our production is sold under the gas sales agreement. The portion of gas subject to the "take or pay" arrangement is agreed on a case-by-case basis, but is generally around 80.0% of the contracted quantity of gas to be supplied. Given the increasing demand for energy in Indonesia, we do not anticipate any difficulty in disposing of any excess gas that is not subject to "take or pay" arrangements.

The price for gas under our gas sales agreements varies, but generally depends on the price of certain reference commodities such as high sulfur fuel oil and the price of methanol, as well as development costs and taxes. See "— Upstream Oil and Gas Production" for details of our average realized sales price of gas for the fiscal years ended December 31, 2018, 2017 and 2016 and for the periods ended March 31, 2018 and 2019.

In 2018, we delivered approximately 36% of the gas we sell annually to our customers through our gas facilities network (including PGN's gas facilities network). See "Business — Pertamina Gas Business — Natural Gas Transmission and Distribution" for more information. Fees for the transmission of gas are generally included in the gas sales price.

PGN's Upstream Business

In April 2018, the Issuer acquired the Government's 56.96% interest in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal

operations with the natural gas distribution and transmission business of PGN. PGN, through its subsidiary PT Saka Energi Indonesia ("Saka"), is engaged in the exploration, development and production of natural gas and crude oil and plays a substantial role in executing PGN's long-term upstream strategy.

As of December 31, 2018, Saka holds interests in eleven oil and gas blocks in Indonesia, of which six are in the production stage and five are in the exploration phase.

Block	Ownership (%)	Status
Ketapang PSC	20	Production
South Sesulu PSC	100	Exploration
Bangkanai PSC	30	Production
West Bangkanai PSC	30	Exploration
Pangkah PSC	100	Production
Muriah PSC	20	Production
Fasken	36	Production
Muara Bakau PSC	11.6	Production
Wokam II PSC	100	Exploration
Pekawai PSC(1)	100	Exploration
West Yamdena PSC(1)	100	Exploration

Note:

(1) Contract with Government signed in 2018.

In 2018, Saka and its subsidiaries produced total lifting of 14.31 mmboe, comprising 7,840 bbls/d of lifting oil, 115 bbtu/d of gas, 95 mtpd of LPG and 60 bbtu/d of LNG.

In the three months ended March 31, 2019 and 2018, Saka and its subsidiaries produced total lifting of 3.02 mmboe/d and 4.16 mmboe/d, respectively, comprising 450,000 bbls and 690,000 bbls of lifting oil, respectively, 8,412 bbtu and 11,406 bbtu of gas, respectively, 7,840 mt and 8,160 mt of LPG, respectively, and 4,226 bbtu and 5,778 bbtu of LNG, respectively. The following table sets forth select information regarding Saka's lifting and sales of oil, gas, LPG and LNG. This information has been derived from publicly available sources and rounded.

	For the Years Ended December 31,		For the Three-Month Periods Ended March 31,	
	2017	2018	2018	2019
Crude oil (in bbls)	3,280,000	2,860,000	690,000	450,000
Natural gas (in mmbtu)	50,615,000	42,087,000	11,406,000	8,412,000
LPG (in mt)	54,803	34,640	8,160	7,840
LNG (in mmbtu)	11,729,000	21,999,000	5,778,000	4,226,000

PGN's exploration and production of oil and gas segment generated revenues of US$585.5 million, which accounted for 15.1% of PGN's net revenues in 2018. Revenues were primarily driven by the Muara Bakau Block that started production in June 2017 and the Sanga Sanga block that was in full production for the year.

For more information on PGN, see "— Pertamina Downstream Business — Pertamina Gas Business — Gas Transmission and Distribution Through PGN."

Geothermal

Our geothermal operations primarily focus on the development of geothermal resources in our concessions. Our geothermal operations involve two types of contractual arrangements. Under our

steam sales agreements, we develop and operate the steam fields and the power plant is developed and operated by other parties, such as PLN. Under our electricity sales agreements, we develop and operate both the steam field and the power plant and sell the electricity produced to PLN.

We manage our geothermal business through our own operations as well as jointly with other partners such as various affiliates of Star Energy. As of March 31, 2019, we had 14 geothermal concessions in Indonesia, covering an area of 23,873.9 km^2. Of our eleven own-operated working areas, six were in the production stage and five were in the exploration or development stage. Of our five working areas jointly operated through JOCs, four were in the production stage and one was in the development stage.

We had a total current installed capacity for power generation in 14 geothermal working areas of 617 MW as of March 31, 2019, which we intend to increase to 672 MW by the end of 2019. In line with the projected acceleration in growth of the geothermal industry in Indonesia, we also intend to increase our installed capacity for power generation significantly by 2025.

Geothermal Reserves, Capacity and Other Operating Data

Our geothermal resources are located in the Sumatra, Java and Sulawesi geothermal regions in Indonesia.

Our estimated proved plus probable geothermal reserves were 1,550 MW, 1,550 MW, 1,365 MW and 1,365 MW as of December 31, 2016, 2017 and 2018 and March 31, 2019, respectively. Our estimates of our geothermal reserves are only based on our own-operated geothermal projects and do not include our jointly operated geothermal projects.

The following table sets forth certain key information relating to our own-operated geothermal areas as of March 31, 2019. We have a 100.0% working interest in each of the projects below, except for our Seulawah project, in which our working interest is 75.0%.

	Estimated Proved and Probable Reserves (MW)	Current Installed Capacity (MW)	Capacity under Development (MW)
Sumatra			
Sibayak	40	12	—
Ulubelu	255	220	—
Lumut Balai	250	*	110
Sungai Penuh	65	*	55
Hulu Lais	250	*	110
Seulawah	0	*	—
Java			
Kamojang	235	235	—
Karaha Bodas	50	30	—
Gunung Lawu	0	*	—
East Indonesia			
Lahendong & Tompasso	220	120	—
Total	**1,365**	**617**	**275**

Note:

* This geothermal area is in the exploration or development phase.

The table below sets forth certain key information relating to our geothermal areas that are operated under JOCs that are operational as of March 31, 2019.

Jointly Operated Areas	Ownership (%)	Contractor(s)	Current Production Capacity (MW)	Share in Capacity (MW)/ Net Operating Income (%)
Gunung Salak, JOC Cibeureum Parabakti	100.0	UNOCAL Geothermal of Indonesia Ltd, Daya Bumi Salak Pratama Ltd	377	4.0
JOC Darajat	100.0	Chevron Darajat Limited, Texaco Darajat Limited, PT Darajat Geothermal Indonesia	271	2.7
JOC Pengalengan	100.0	Star Energy Geothermal Wayang Windu Limited	227	4.0
JOC Sarulla	100.0	PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Ltd, Orsarulla Inc., Kyuden Sarulla Pte., Ltd.	330	4.0
Tabanan	100.0	Bali Energy Limited	0	4.0

Geothermal Production

The following table sets forth our aggregate geothermal production for the periods indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Total annual production					
Steam (mt)	22,642	28,798	31,086	7,119	7,720
(expressed in electricity equivalent) (GWh)	3,245	3,900	4,182	959	1,021
Average daily production					
Steam (mt)	62.0	78.9	85.2	79.1	85.8
(expressed in electricity equivalent) (GWh)	8.3	10.7	11.5	10.7	11.3

Geothermal Exploration and Development

To begin exploration and development in a concession, we carry out several tests and surveys followed by exploratory drilling, first to validate and then to quantify the size of the potential geothermal resource. Resource validation and exploratory drilling is a long process that requires substantial capital investment, as it may necessitate the drilling of shallow temperature-gradient wells, "slim holes," exploration wells, and production-sized exploration wells. We do not expect to succeed in developing every resource that undergoes exploration activity and will cease exploration activities on potential geothermal resources that will not support commercial operations.

Geothermal Sales and Distribution

We sell all of the electricity generated by our geothermal operations to PLN via electricity sales contracts. PLN in turn sells the energy to third-party customers in Indonesia. Each electricity sales contract has a term of 30 years and is on a 90% take-or-pay basis. The base price for electricity from our Lumut Balai and Ulubelu plants is about US$0.0753 per KWh. The base prices for electricity from our Lahendong, Karaha and Kamojang plants are about US$0.0825 per KWh, US$0.0825 per KWh and US$0.094 per KWh respectively. We base our price increases over the life of the contract on the United States Producer Price Index.

Steam generated by our geothermal operations is sold through steam sales contracts to PLN or other private third parties (who use the steam to generate electricity which is in turn sold to PLN and ultimately to third-party customers in Indonesia). Each steam sales contract has a term of 30 years. The base price for steam from our Ulubelu plant is about US$0.0420 per KWh. The base price for steam from our Lahendong 1, 2, 3 and 4 plants is about US$0.0430 per KWh. The base price for steam from our Hululais plant is about US$0.043 and Sungai Penuh plants is about US$0.0430 per KWh. The base price for steam from our Sibayak plant is about US$0.022 per KWh. The base price for electricity from our JOC Sarulla plant is between US$0.0316 and US$0.0790 per KWh. The base price for steam from our JOC Cibeureum Parabakti plant is between US$0.062 and US$0.072 per KWh. The base price for electricity from our JOC Pangalengan plant is between US$0.0479 per KWh and US$0.0966 per KWh. The base price for steam from our JOC Darajat plant is between US$0.016 per KWh and US$0.051 per KWh, while the electricity price is between US$0.068 and US$0.071 per KWh.

Under each of our steam sales contracts with PLN, we are able to escalate our prices for steam on a 2% per annum basis. Our Gunung Lawu, Seulawah and Tabanansites are still in the exploration stage.

Pertamina Downstream Business

Overview

Our downstream business includes several business lines: oil and gas refining, marketing, trading and shipping of crude oil, refined oil and gas products, distributing subsidized fuel products and operating certain LNG assets on the Government's behalf. We categorize our refined oil and gas products as (i) retail oil-based fuel, such as motor gasoline and diesel, (ii) special fuel products, such as aviation gasoline, (iii) non-fuel and petrochemical products, such as green coke and lube-base oil, and (iv) gas-based fuel, such as LPG.

We are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia. Our total production capacity of 1,031.0 mbbls/d in 2018 comprised nearly all of Indonesia's total refining capacity of 1.1 mmbbls/d, based on Wood Mackenzie data. We are also the largest oil and gas refiner in Southeast Asia region in terms of refining capacity, according to Wood Mackenzie. As of March 31, 2019, we had six refineries that have a total production capacity of approximately 1,031.0 mbbls/d and an average NCI of 6.0. In addition, we hold a 48.6% non-controlling ownership interest in the PT Trans Pacific Petrochemical Indotama ("TPPI") petrochemical refinery.

Annual fuel production, comprised of retail oil-based fuel, special fuel products and gas-based fuel, reached 264.9 mmbbls for the year ended December 31, 2018 and 65.05 mmbbls for the three-month period ended March 31, 2019. Non-fuel and petrochemical production reached 27.5 mmbbls for the year ended December 31, 2018 and 6.9 mmbbls for the three-month period ended March 31, 2019. See "— Refining" for more information on our refining business.

We hold significant interests in the downstream infrastructure and distribution networks in Indonesia, which are comprised of pipelines, fuel stations and depots, and shipping vessels.

As of March 31, 2019, we owned 117 fuel terminals, 22 LPG terminals and depots, 6,878 Pertamina-branded retail fuel filling stations, 647 fuel gas filling stations, 68 aviation fuel depots, 193 harbors and Terminal Khusus Untuk Kepentingan Sendiri and three lube oil blending plants and operated 262 tankers.

We believe that because of our extensive distribution infrastructure and assets in Indonesia, we have been granted the PSO mandate by the Government to produce, supply and distribute the majority

of subsidized fuel in Indonesia. This PSO mandate requires us to distribute fuel at subsidized rates fixed by the Government. We are subsequently reimbursed by the Government for our costs in accordance with a prescribed formula. See "— PSO" for more information on our PSO mandate.

To optimize the margins from our refined products, we also further refine low sulfur waxy residual fuel oil and naphtha, which are intermediate products from the refining process.

Downstream Strategy

In our refinery operations, we aim to ensure that all of our refineries are competitive and operate efficiently and profitably. We intend to improve our operating efficiency and effectiveness by restructuring and enhancing our existing downstream operations, including our refineries. We plan on revitalizing our existing refineries, improving our refinery complexity index and developing new refineries. In each of the years ended December 31, 2016, 2017 and 2018 and for the three months ended March 31, 2019, our actual capital expenditures for our downstream segment were US$801.3 million, US$1,529.1 million, US$1,135.6 million and US$171.6 million, respectively.

Our current development strategy includes plans to increase refinery capacity, to develop our petrochemical business, to increase our crude oil throughput and achieve product quality levels that comply with EURO V specifications. We continue to execute our Refinery Development Master Plan ("RDMP"), launched in 2013, with the objective of meeting growing fuel demand in Indonesia with increased domestic production. Under the RDMP, we aim to comprehensively upgrade our refineries to significantly increase their production capacity and complexity, as well as improve their production capabilities for fuel products that comply with EURO V specifications. As part of RDMP, we completed RFCC Cilacap and the Cilacap Blue Sky Project and are in the process of implementing revitalization and upgrade of RU V Balikpapan and RU IV Cilacap. In October 2016, we formed the Directorate of Refinery and Petrochemicals Mega Projects focusing on addressing mega projects including the revitalization program of existing refineries and construction of new Grass Root Refineries ("GRR"). We intend to continue to increase our refinery portfolio and expand our petrochemical business. We are also exploring the construction of two new refineries with fully integrated petrochemical plants, in Tuban, East Java and in Bontang, East Kalimantan, each with a primary production capacity of 300 mbbls/d.

In the long term, we also plan to invest in our new and renewable energy business. We are exploring new initiatives such as biofuel products, biorefineries, battery storage technology, solar photovoltaic power plants, coal to chemical or gas conversion systems and combined cycle geothermal technology.

We also plan to opportunistically pursue strategic alliances and joint ventures, because we believe that by developing downstream facilities through strategic alliances, we can supplement and strengthen our technical and management capabilities. Towards these goals, we have formed a joint venture with PJSC Rosneft Oil Company to develop our GRR in Tuban, East Java. See "— Refining Facilities" for our expansion plans for our existing refineries and "— Planned Development of New Refineries" for a description of our planned new refineries.

We plan to maintain our leading position in marketing and trading oil and gas in Indonesia and under our PSO mandate. We plan to strengthen our dominant distribution operations and infrastructure and capture a substantial retail market share going forward by expanding our company-owned and company-operated fuel stations. We intend to further augment our position by exiting from non-strategic retail locations. We plan to capitalize on our long established brand name.

We intend to improve our LPG business by accelerating the conversion of kerosene to LPG and developing quality LPG service infrastructure. We intend to further streamline our distribution by

obtaining more ships and building new LPG terminals (including refrigerated and pressurized terminals).

Finally, in 2017, we established our RTC to centralize and integrate our research and development initiatives. In the downstream sector, the RTC would focus on, among other things, developing technologies for biofuels, biomass gasification and renewable power sources.

Oil and Gas Refining

Process

Our refineries process crude oil to produce refined oil and gas products. Crude oil is generally sent through three separate process units. The first separates the crude oil through the application of heat and energy into chemical components a process called fractionation (such components are "fractions"). The second process unit processes the lower value fraction grades in order to create higher value refined products and the third process unit treats and blends the higher value fraction grades with lower value fraction grades to ensure that the end product meets the quality standards of our customers. The higher value fraction grades produced from the first process unit are aviation turbine fuel and gas oil. See "— Description of Existing Refineries" for a description of the secondary products that each of our refineries can produce through the secondary process.

Production

The crude oil we use as feedstock from our refineries is sourced from our own production or imported under term contracts or under spot contracts. See "— Integrated Supply Chain." The natural gas we process in our refineries is sourced mostly from our own production.

The following table presents our total refinery capacity, intake and production for the periods indicated.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Capacity					
Refining capacity[(1)] (mbbls/d)	1,031.0	1,031.0	1,031.0	1,031.0	1,031.0
Average NCI	5.7	5.7	6.0	5.7	6.0
Average utilization rate[(2)] (%)	77.4	79.0	83.1	85.2	81.0
Annual intake					
Produced crude oil (mmbbls)	160.0	179.8	200.0	47.5	56.7
Imported crude oil (mmbbls)	134.3	117.6	112.9	31.5	18.5
High octane motor gas import (mmbbls)	0.2	—	0.4	79.0	75.1
Natural gas (mmboe)	1.8	1.6	1.7	0.4	0.4
Annual production					
Fuel (mmbbls)	244.6	262.8	264.9	65.5	65.1
Non-fuel and petrochemicals (mmboe)	25.5	29.0	27.5	7.5	6.9
Average daily production					
Fuel (mbbls/d)	668.2	1,451.7	725.7	727.4	722.8
Non-fuel and petrochemicals (mboe/d)	69.6	160.4	75.3	83.8	76.9

Notes:

(1) Based on design capacity.

(2) Based on processing capacity.

See "— Downstream Products" for more information on the products produced from our refineries.

Refining Facilities

We own and operate six refineries with total refining capacity of 1,031.0 mbbls/d and an average NCI of 6.0. In addition, we hold a 48.6% non-controlling ownership interest in the TPPI petrochemical refinery. Some of our refineries are operationally integrated with petrochemical refineries that produce non-fuel and petrochemical products. Our petrochemical refineries produce aromatic products and olefin products that are used as raw materials for textile, rubber, synthetics, plastics and other industries.

Our largest refinery is RU IV Cilacap, which is located in Central Java and has a refining capacity of 348 mbbls/d. Our second largest refinery is RU V Balikpapan, which is located in Kalimantan and has a refining capacity of 260 mbbls/d. Both refineries process crude oil.

In recent years, we have made significant capital investments in facility expansions and upgrades to improve product quality and increase production capacity and efficiency of our plants to meet evolving market demand and environmental requirements in Indonesia.

These capital expenditures were incurred primarily in connection with routine maintenance, facility expansions and upgrades of our refineries, and research and development in new processing technologies. In addition, we have focused on enhancing our processing technologies, capabilities and methods. These efforts have enabled us to improve the quality of refined products at our refineries, particularly gasoline and diesel, and to increase the flexibility of our refineries in crude processing. We have increased the production capacity of our plants and modified the fuel-loading infrastructure to increase the speed of fuel fillings at our loading facilities. We have also maintained the efficiency and utilization rate of our refineries. In each of the three years ended December 31, 2016, 2017 and 2018 and in the three-month period ended March 31, 2019, the average utilization rate of the primary processing capacity of our refineries was 77.4%, 79.0%, 83.1% and 81.0%, respectively. We also intend to continue to make capital investments in facility expansions and upgrades as described below.

The table below sets forth our refinery portfolio and planned key expansion and upgrading activities as of March 31, 2019.

Fuel

Refinery	Current Design Capacity (mbbls/d)	NCI	Key Expansion and Upgrade Details and Target Completion Dates
RU II Dumai	170	7.5	• Develop the engineering package of the Calciner Project, which consists of the construction of a coke factory that will process 300kTA Green Petroleum Coke ("GPC") and an additional 100 kTA GPC imports into 300 kTA of anode grade Calcinated Petroleum Coke ("CPC") • Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater • Open access for crude oil receiving facilities

Refinery	Current Design Capacity (mbbls/d)	NCI	Key Expansion and Upgrade Details and Target Completion Dates
RU III Plaju	118	3.1	• Open access for crude oil receiving facilities • Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater
RU IV Cilacap	348	6.3	• Change the reconfiguration of the naptha processing complex RU IV Cilacap to improve the quality of fuel products form RON 88 to RON 92. • Increase the flexibility of processing crude oil from 0.1% sulfur content to 2.0%. • Increase the operational processing capacity up to 1.1 times from the existing capacity. • Improve product quality from EURO II standards to Euro V standards. • Improve the refinery's NCI to 9.0.
RU V Balikpapan	260	3.4	• Increase the flexibility of processing crude oil from 0.4% sulfur content to 2.0% by 2025. • Increase the operational processing capacity up to 1.4 times from the existing capacity by 2023. • Improve product quality from EURO II standards to Euro IV and Euro V standards by 2023. • Improve the refinery's NCI to 9.0.
RU VI Balongan	125	11.9	• Increase the flexibility of processing crude oil from 0.2% sulfur content to 1.0%. • Increase the operational processing capacity up to 1.3 times from the existing capacity. • Improve product quality from EURO II standards to Euro IV and Euro V standards
RU VII Kasim/Sorong	10	2.4	• Open access for crude oil receiving facilities • Improve product quality of diesel from EURO II standards to Euro V standards by installing new distillate hydrotreater
Total	**1,031.0**	**6.0**	

Non-fuel Petrochemicals

Refinery	Non-fuel petrochemicals produced	Current design Capacity (Mtons/year)
RU IV Cilacap	Paraxylene	149,856.8
RU III Plaju	Polypropylene	45,214.1
RU II Dumai	Green coke	393,230.4
Total		**588,301.3**

Since late 2018, we have also been in coordination with the Ministry of Finance to assume partial ownership and management of PT Trans Pacific Petrochemical Indotama and restart operations of a petrochemical refinery. We currently hold a 48.6% non-controlling ownership interest in the TPPI refinery.

Description of Existing Refineries

RU II Dumai

RU II Dumai is located in Sumatra and consists of a refinery unit at Dumai. The unit at RU II Dumai commenced operations in 1972 and has undergone periodic revamps and modifications. RU II Dumai is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil, naphtha, LPG, green coke, feedstock for lube base oil plants and low sulfur waxy residual fuel oil ("LSWR") via its primary and secondary process units. RU II Dumai is comprised of a crude distillation unit ("CDU"), high vacuum unit ("HVU"), hydro-cracker units ("HCU"), delay coker units and platformer units.

As of March 31, 2019, RU II Dumai had an NCI of 7.5, its primary process units had a processing capacity of 153.2 mbbls/d through its CDU and its secondary process units had a processing capacity of 57.5 mbbls/d through its hydro-cracker unit, 14.0 mbbls/d through its platformer unit and 31.2 mbbls/d through its delay coker unit.

RU II Dumai uses domestic crude oil as its raw material. The crude oil processed at RU II Dumai comes from our own production and from other oil and gas producers, such as Chevron, and is transported by pipelines and tankers. In 2018, the average total output of RU II Dumai was 140.1 mbbls/d, and the total amount of green coke produced was 393,230.4 Mton. For the three months ended March 31, 2019, the average total output of RU II Dumai was 147.4 mbbls/d, and the total amount of green coke produced was 108,893.0 Mton. In 2018 and the three months ended March 31, 2019, the primary processing capacity utilization rate at RU II Dumai was 84.8% and 90.1%, respectively.

To upgrade the quality of GPC, we intend to build a calciner with a production capacity of 300,000 mtpa by 2020 in order to produce CPC. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

RU III Plaju

RU III Plaju is located in Musi, Sumatra. It commenced operations in 1935 and underwent revamps and modifications in 1982 and 1994. RU III Plaju is able to produce motor gasoline, kerosene, aviation turbine fuel, aviation gas, gas oil, industrial fuel oil, naphtha, LPG, polypropylene, solvent and hydrocarbon refrigerants via its primary and secondary process units.

As of March 31, 2019, RU III Plaju had an NCI of 3.1, its primary process units had a processing capacity of 87.3 mbbls/d and its secondary process units had a processing capacity of 18.3 mbbls/d through its fluidized catalytic cracking united ("FCCU") and 52,758.8 Mton per year through its polypropylene unit. RU III Plaju is comprised of CDU, HVU, FCCU and polypropylene units.

RU III Plaju uses domestic crude oil as its raw material. Substantially all of the crude oil processed at RU III Plaju comes from our own production and from other oil and gas producers and is transported by pipelines and small tankers. In 2018, the average total output of RU III Plaju was 98.9 mbbls/d and polypropylene production was 45,214.1 mt. In the three months ended March 31, 2019, the average total output of RU III Plaju was 100.9 mbbls/d and polypropylene production was 13,189.4 mt. In 2018 and the three months ended March 31, 2019, the primary processing capacity utilization rate at RU III Plaju was 79.0% and 69.2%, respectively.

We are currently making improvements to our crude-receiving facility. The objective of this project is to decrease freight costs and optimize the crude intake capacity. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

RU IV Cilacap

RU IV Cilacap consists of two refinery units located in Cilacap, Java. The refinery units at RU IV Cilacap commenced operations in 1976 and 1983 and both were revamped and modified in 1999. RU IV Cilacap is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil, industrial fuel, LSWR, naphtha, LPG, paraxylene, benzene, lube based oil mineral, solvent and asphalt via its primary and secondary process units. RU IV Cilacap is comprised of two fuel oil complex units, one lube oil plants, one asphalt unit and one paraxylene unit.

As of March 31, 2019, RU IV Cilacap had an NCI of 6.3, its primary process units had a processing capacity of 287.3 mbbls/d and its secondary process units had a processing capacity of 206,958.7 Mton of paraxylene per year and 300,260.6 Mton of lube base oil per year.

RU IV Cilacap uses imported light sweet and sour crude and domestic light sweet crude as its raw materials. In 2018, approximately 38.0% of the crude oil processed at RU IV Cilacap came from our own production and from other domestic oil and gas producers, and the balance was imported from Asia, West Africa and the Middle East by tankers. In 2018, the average total output of RU IV Cilacap was 294.9 mbbls/d, paraxylene production was 1,089.4 mbbls, asphalt production was 1,562.7 mbbls, and lube base oil production was 2,456.2 mbbls. For the three-month period ended March 31, 2019, the average total output of RU IV Cilacap was 281.3 mbbls/d, paraxylene production was 376.1 mbbls, asphalt production was 195.8 mbbls, and lube base oil production was 609.1 mbbls. In 2018 and the three months ended March 31, 2019, the primary processing capacity utilization rate at RU IV Cilacap was 85.9% and 82.6%, respectively.

We are performing an upgrade of RU IV Cilacap to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.1% to 2.0%. We also plan to increase fuel production and operational processing capacity up to 1.1 times its existing capacity. We aim to improve RU IV Cilacap's product quality from EURO II standards to EURO V standards, and to increase the profitability of the refinery from US$3.00 per barrel to US$12.60 per barrel. In addition, under our Cilacap Blue Sky Project, we plan to change the configuration of the naptha processing RU IV Cilacap to improve the quality of our fuel products from lower octane Gasoline RON 88 to the high-octane fuel RON 92.

As part of our revitalization program, we are also making improvements to our residue fluid catalytic-cracking unit in RU IV Cilacap, in order to process LSWR into products, such as RON 92 gasoline, LPG and propylene. This program is expected to increase RU IV Cilacap's production capacity of RON 92 gasoline by 35.7 mbbls/d, of propylene by 4.3 mbbls/d and of LPG by 9.0 mbbls/d.

RU V Balikpapan

RU V Balikpapan consists of two refinery units located in Balikpapan, Kalimantan. The refinery units at RU V Balikpapan commenced operations in 1922 and 1983 and the first unit was revamped/ modified in 1997. RU V Balikpapan is able to produce motor gasoline, kerosene, aviation turbine fuel, gas oil and LSWR via its primary process unit and naphtha, LPG, oil base mud and wax via its primary and secondary process units.

As of March 31, 2019, RU V Balikpapan had an NCI of 3.4, its primary process unit had a processing capacity of 236.8 mbbls/d and its secondary process units had a processing capacity of 52.3 mbbls/d for its HCU and 20.1 mbbls/d for its platformer unit. RU V Balikpapan is comprised of a CDU, HVU, HCU and platformer and wax plant units.

RU V Balikpapan uses domestic and imported light sweet crude as its raw material. In 2018, more than half of the crude oil processed at RU V Balikpapan came from our own production and from other domestic oil and gas producers and was transported by pipelines and via tankers, while the balance was imported from Asia and West Africa and was transported by tankers. For the years ended December 31, 2017 and 2018 and the three-month period ended March 31, 2019, the average total output of RU V Balikpapan was 220.0 mbbls/d, 241.2 mbbls/d and 243.9 mbbls/d, respectively, and the primary processing capacity utilization rate at RU V Balikpapan was 82.4%, 90.3% and 91.1%, respectively.

We are performing an upgrade of RU V Balikpapan to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.4% to 2.0%. We also plan to increase its fuel production and operational processing capacity to up to 1.4 times its existing capacity. We aim to improve its product quality from EURO II standards to EURO V standards.

RU VI Balongan

RU VI Balongan is located in Balongan, Java. RU VI Balongan commenced operations in 1994 and was revamped or modified in 2005. RU VI Balongan is able to produce motor gasoline, kerosene, gas oil, high octane motor gasoline and propylene via its primary and secondary process units.

As of March 31, 2019, RU VI Balongan had an NCI of 11.9, its primary process unit had a processing capacity of 122.4 mbbls/d and its secondary process units had a processing capacity of 74.9 mbbls/d of RCC.

RU VI Balongan comprises a CDU, an atmospheric residual hydro-demetalizer, RCC, propylene recovery unit, propylene receiving units, a residue catalytic cracking off-gas propylene project and a LPG plant.

RU VI Balongan uses domestic crude and imported light sweet crude as its raw materials. In 2018, 61.9% of the crude oil processed at RU VI Balongan came from our own production and from other domestic oil and 100% was transported by tankers and pipelines.

For the years ended December 31, 2017 and 2018 and the three-month period ended March 31, 2019, the average output of RU VI Balongan was 112.7 mbbls/d, 107.3 mbbls/d and 159.7 mbbls/d, respectively, and the primary processing capacity utilization rate at RU VI Balongan was 90.2%, 85.9%, and 97.9% respectively.

We also process LSWR, an intermediate product from our RU IV Cilacap refinery, and naphtha, an intermediate product from our RU II Dumai, RU III Plaju, RU IV Cilacap and RU V Balikpapan refineries, at RU VI Balongan. In 2018, we processed 8,428.4 mbbls of LSWR and 16,467.5 mbbls of naphtha at RU VI Balongan.

We are performing an upgrade of RU VI Balongan to increase the facility's flexibility to process crude oil with sulfur content ranging from 0.2% to 1.0% and improve its product quality from EURO II standards to EURO V standards. Currently, the feasibility study relating to the foregoing is in progress and we expect it to be completed in late 2019.

RU VII Kasim/Sorong

RU VII Kasim/Sorong is located in Sorong, Papua. RU VII Kasim/Sorong commenced operations in 1995. RU VII Kasim/Sorong is able to produce motor gasoline, kerosene, and gas oil via its primary

and secondary process units. RU VII Kasim/Sorong uses domestic crude oil as its raw material. All of the crude oil processed at RU VII Kasim/Sorong is comprised of the Government's crude entitlement from other oil and gas producers and is transported by pipelines to our refinery.

As of March 31, 2019, RU VII Kasim/Sorong had an NCI of 2.4, its primary process unit had a processing capacity of 6.6 mbbls/d its secondary process units had a processing capacity of 1.6 mbbls/d for its platformer unit.

RU VII Kasim/Sorong is comprised of a CDU, a naphtha hydro treating unit and platformer unit.

As of March 31, 2019, we were in the EPC bidding stage in relation to the prospective construction of open access infrastructure for crude oil receiving at RU VII Kasim. The objective of this project is to optimize the crude intake capacity. In addition, we also intend to install a new distillate hydrotreating unit to produce low-sulfur diesel, in order to comply with future government regulations.

Planned Development of New Refineries

We intend to construct a new refinery in Tuban, East Java with a primary processing capacity of 300.0 mbbls/d with fully integrated petrochemical plants, through a joint venture with PJSC Rosneft Oil Company. The project is in the land acquisition phase, and the proposed site of the new refinery is pending Government approval. We are evaluating locations for a proposed new refinery in East Java, subject to the joint venture being awarded the license to the proposed project. These projects are targeted for completion in 2025.

We have also been appointed by the Government to construct and operate a new refinery in Bontang through a joint venture with a consortium led by Overseas Oil & Gas LLC ("OOG"). The facility is expected to have a production capacity of 300.0 mbbls/d. The project would be funded by OOG and the consortium and has the potential provide us with access to additional crude oil supply. The project is in the pre-feasibility study phase.

We currently anticipate that our planned developments of new refineries in Bontang and Tuban will be eligible for favorable corporate income tax treatment under Regulation of the Minister of Finance Number 150/PMK.010/2018 on Provision of Corporate Income Tax Holiday Facility for investments in pioneer industries.

Downstream Products

Our downstream refined products are:

- Motor gasoline, which comprises transportation fuel marketed under our brands "Premium" (RON 88), "Pertalite" (RON 90), "Pertamax" (RON 92), "Pertamax Turbo" (Ron 98) and "Pertamax Racing" (RON 100);

- Automotive diesel oil, which we refer to as solar and biosolar fuel for common diesel oil and higher specification automotive diesel oil marketed under our brands "Dexlite" and "Pertamina Dex";

- Industrial diesel, which consists of diesel oil and marine gas oil;

- Industrial and marine fuel oil;
- Kerosene;
- Aviation turbine fuel, marketed under our brands "Avtur";
- Gas-based products, which comprise LPG, refrigerants and aerosol. Our LPG products are marketed under the name "Elpiji" in 3kg, 12kg, and 50kg packaging and skid tanks, "Bright Gas" in 3kg, 5.5kg, 12kg, and 220 grams packaging;
- Lube base oil, which we refer to as lubricants; and
- Petrochemicals and others, which comprise bitumen, polytam, solvent, green cokes, waxes, rubber processing oil (paraffinic oil), paraxylene, propylene, benzene and sulfur.

The table below sets forth production volume for our refined products for the periods presented.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
	(in thousands of bbls)				
Motor gasoline	97,889.8	93,364.2	82,009.5	20,540.2	19,635.0
Kerosene	4,206.4	2,342.0	3,482.6	892.1	1,010.5
Automotive diesel	127,668.7	132,845.1	139,612.8	34,967.9	34,452.2
Industrial diesel	917.6	464.4	449.8	66.1	106.9
Industrial fuel	12,325.2	10,898.2	13,087.70	2,626.6	3,004.1
Aviation turbine fuel	22,772.3	22,841.5	26,250.0	6,344.0	6,823.5
LPG	10,291.1	10,102.9	9,854.3	2,467.7	2,478.2
Refrigerants	4.3	6.1	8.1	1.3	2.3
Lube base oil	2,203.4	3,397.9	2,456.2	1,158.6	609.1
Petrochemicals and others	30,620.7	30,910.2	24,709.07	7,779.2	7,351.5
Total	**308,899.5**	**307,172.5**	**301,920.1**	**76,843.7**	**75,473.3**

We also import refined products for distribution. In 2018, we imported 145.8 mmbbls of refined products under term supply contracts and spot contracts. Our major providers of refined products are Hin Leong (Pte) Ltd and Shell International Eastern Trading Company.

Pertamina Gas Business

Overview

Our gas business principally involves the following: (i) LNG production, transport and export, (ii) gas transmission and distribution through our gas pipeline network, (iii) gas trading, which we undertake in conjunction with our gas transmission and distribution business, (iv) CNG distribution and sale pursuant to a mandate from the Government which aims to promote the use of CNG by public and private transportation vehicles, with the goal of reducing domestic dependence on subsidized motor gasoline and automotive diesel oil (the "CNG mandate"), (v) manage Indonesia's "City Gas" network, which is the country's gas distribution network for household use, in 21 cities across Sumatra, Java, Kalimantan and Sulawesi, pursuant to an appointment from the Government.

In April 2018, we acquired PGN, which is a leading integrated natural gas utility in Indonesia, with a dominant position in the natural gas downstream business through the largest distribution and

transmission pipeline network in Indonesia. For information on PGN's natural gas operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Our Recently Acquired Subsidiary, PGN; PGN Acquisition and Recent Restatement of Our Financial Statements" and "— PGN Operations." In December 2018, we transferred Pertagas to PGN as described in further detail below.

Gas Transmission and Distribution Through PGN

Overview

In April 2018, the Issuer acquired the Government's 56.96% interest in PGN to establish a state-owned oil and gas holding enterprise that combines our fully integrated oil, gas and geothermal operations with the natural gas distribution and transmission business of PGN. PGN is a public company that is listed on the Indonesia Stock Exchange, under the ticker symbol "PGAS," and certain additional information regarding PGN, including its annual reports and financial statements, are publicly available. The Issuer is the largest shareholder of PGN.

PGN is a leading integrated natural gas utility in Indonesia, with a dominant position in the natural gas downstream business through the largest distribution and transmission pipeline network in Indonesia. PGN's core business is its gas distribution and transmission segments, through which it operates its downstream business. PGN's gas distribution and transmission segments accounted for 77.8%, 79.2% and 83.5% of its net revenues in 2017 and 2018 and the three months ended March 31, 2019, respectively. PGN's gas distribution and transmission involves purchasing natural gas from upstream gas suppliers and reselling it to industrial, commercial and residential customers through its distribution infrastructure as well as transporting natural gas owned by third parties, through its high-pressure transmission pipelines from upstream suppliers for delivery directly to customers of the upstream suppliers.

PGN's distribution and transmission networks represented approximately 10,099 km of pipelines as of March 31, 2019 and the average volume of natural gas delivered through its distribution and transmission business was approximately 2,904 MMscfd in 2018. PGN's distribution network served 2,331 commercial, industrial and power customers and 231,066 households and small businesses in the three months ended March 31, 2019. PGN's transmission network represented 4,751 km of pipelines as of March 31, 2019 and comprised its Wampu-Belawan, South Sumatra-West Java, Grissik-Duri, Grissik-Batam-Singapore, Kalija and Kepodang-Tambak Lorok transmission pipelines.

For the years ended December 31, 2016, 2017 and 2018 and the three-month periods ended March 31, 2018 and 2019, PGN had net revenues of US$2,934.8 million, US$2,969.6 million, US$3,430.5 million, US$797.8 million and US$860.5 million, respectively. For the years ended December 31, 2016, 2017 and 2018 and for the three-month periods ended March 31, 2018 and 2019, PGN had profit of US$308.6 million, US$147.8 million, US$242.5 million, US$81.0 million and US$82.8 million, respectively.

Transfer of Pertagas to PGN

In December 2018, PGN acquired from the Issuer a 51.0% stake in PT Pertamina Gas. Through the acquisition of PT Pertamina Gas, PGN also acquired PT Pertamina Gas' subsidiaries PT Pertagas Niaga, PT Perta Arun Gas, PT Perta Daya Gas and PT Perta Samtan. The Issuer retains a 49.0% direct stake in PT Pertamina Gas. While the Issuer's effective total ownership in PT Pertamina Gas (i.e. including its indirect stake via its ownership of PGN) is reduced from 100.0% to 78.05%, the transfer of Pertagas to PGN is intended to grow our gas business by creating an extensive and far-reaching distribution and transmission pipeline network in Indonesia and unlocking benefits of scale .

The transaction consolidated our gas transmission and distribution business, gas pipeline network and trading business with those of PGN. PGN acquired Pertagas' transmission pipeline network of approximately 2,500 km (excluding city gas pipelines) that covers Sumatra, Java and East Kalimantan. PGN's gas pipeline network now represents approximately 72% of the gas pipelines in Indonesia, according to BPH Migas. PGN's transmission facilities currently have a capacity of approximately 1,283 mmcf/d (Pertagas) and 703 mmcf/d (other PGN facilities). This gas pipeline network transports gas that we produce to our customers, such as PLN and fertilizer factories. PGN also enters into agreements with other gas producers such as our subsidiary, PEP, and PT Medco E&P Indonesia to allow them to transport the gas that they produce through our gas pipeline network.

PGN's Natural Gas Distribution and Transmission Business

PGN's distribution business involves purchasing natural gas from upstream gas suppliers and reselling it to industrial, commercial and residential customers through its distribution infrastructure. PGN's distribution business therefore comprises natural gas distributing and trading activities. PGN sources natural gas from gas fields located in Indonesia which are either directly connected to its distribution network or are connected to its distribution networks through off-take stations. This natural gas can be transported through its transmission network or other parties' open access transmission networks under pressure ranging from 400 to 1,050 psi. PGN's distribution network is divided into three categories that operate under different pressure and are separated by pressure reduction stations. The first category comprises high-pressure pipelines that are used to distribute natural gas to power stations and certain other large industrial customers, the second category comprises medium-pressure pipelines that are used to distribute natural gas to industrial customers and the third category comprises low-pressure pipelines that are used to distribute natural gas to residential and small commercial customers.

PGN's transmission business currently comprises downstream activities such as transporting natural gas owned by third parties through its high-pressure transmission pipelines from upstream suppliers for delivery directly to customers of the upstream suppliers. PGN's transmission business covers areas in North Sumatra, South Sumatra, Jambi, Riau, Riau archipelago, Lampung, Banten and West Java and serves shippers and off-takers along its transmission pipeline. PGN generates revenues by charging a tariff to its customers who use its transmission pipeline to transport their natural gas. The tariff rate is determined by BPH Migas. The primary factors affecting revenues from our transmission business are tariff rate and quantity of natural gas transmitted. Transportation service contracts which govern transmission services have terms that generally range from ten to twenty years.

The following table shows PGN's distribution and transmission infrastructure as at the dates indicated:

	As of or for the Years Ended December 31,			As of or for the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
Distribution Network length (km)	4,994[(1)]	5,169[(1)]	5,343[(1)]	5,169[(1)]	5,348
Average Distribution gas sales (MMscfd)	803	772	967	953	919
Transmission Network length (km)	2,284[(1)]	2,284[(1)]	4,573[(1)]	2,284[(1)]	4,751
Transmission volumes (MMscfd)	795	729	2,101	2,098	1,985

Note:

(1) Excludes transmission network assets formerly owned by our Company (excluding PGN) and acquired from the Company by PGN in December 2018.

Natural Gas Distribution and Transmission Growth Strategy

We have expanded and plan to continue expanding our gas pipeline network to meet our growing demand and to better service our customers.

- *Grisik-Pusri pipeline*. In 2018, we completed construction of the Grisik-Pusri pipeline, which connects the ConocoPhilipps Grisik Gas Plant in Musi Banyuasin Regency to the fertilizer factory PT Pupuk Sriwidjaja (Pusri) in Palembang. It is approximately 175 km long, with a capacity of 161 mmcf/d. The volume of gas supplied to Pusri is expected to be approximately 70 mmscfd in 2019.

- *Gresik-Semarang pipeline*. The Gresik-Semarang pipeline will connect gas sources in East Java to consumers in Gresik and Semarang. It is expected to be approximately 273.0 km long, with a capacity of 500.0 mmcf/d. It is expected to deliver gas from the JTB field in East Java. The pipeline is expected to be completed in the fourth quarter of 2019.

- *Duri-Dumai pipeline*. The Duri-Dumai pipeline will connect Duri to Dumai. The pipeline is expected to be approximately 67 km long, with a capacity of 268 mmcf/d. The pipeline was completed in April 2019.

LNG

Our LNG business comprises the ownership of a 70% share of the PT Badak NGL plant in Bontang, the operation of the Arun regasification plant in Aceh and FSRU in West Java and Lampung, the export and transport of LNG on behalf of the Government and the trading of Pertamina's LNG portfolio in the domestic and global market.

We were the operational asset manager of the Badak LNG plant from the late 1970's until 2017, though ownership of the assets has remained with the Government. In 2017, PT Badak NGL was appointed by the Minister of Finance as the Badak LNG plant's new operational asset manager. PT Badak NGL's appointment as operational asset manager of the Badak LNG plant expired at the end of 2018 and Pertamina is the current operational asset manager of the Badak LNG plant. The Badak plant's current feedstock is 1200-1300 mmscfd. The Badak plant has an installed capacity of 22.4 mtpa and a current production capacity of 8.4 mtpa.

We have remained the Government's designated seller for the export and transport of LNG produced at the Badak LNG plant in exchange for a marketing fee. Our LNG export customers are located in Japan, South Korea, China and Taiwan, and aggregate contracted and spot volume is approximately 8.5 mtpa. We have also been appointed by the Government to sell LNG from the Bontang LNG plant to an LNG FSRU in West Java that we operated as a joint venture with PGN prior to our acquisition of PGN in April 2018 and now solely operate. The arrangement provides for an aggregate sale volume of 11.8 mt from the Bontang LNG plant to the West Java LNG FSRU over the 2012 to 2022 period. The West Java LNG FSRU has a total capacity of 3.0 mtpa and commenced production in May 2012.

We also operate the Arun plant in Aceh, which is a former LNG liquefaction plant that we transformed into a receiving and regasification terminal and LNG storage facility after the Government ceased production of LNG at Arun in 2014 due to the depletion of the natural gas reserves. The Arun plant primarily regasifies LNG produced at our Badak LNG plant, and its receiving and regasification terminal has a capacity of 3.0 mtpa. We also built a gas pipeline between the Arun plant and the industrial area in Belawan, Medan in order to sell gas from the regasification of LNG to industrial

customers in the Arun area and the Belawan industrial area. As of December 31, 2018 and as of March 31, 2019, we sold 0.9 mtpa and 0.2 mtpa, respectively, of the gas produced through the regasification process at the Arun plant.

Through PHE, we own a 29% minority interest in PT Donggi-Senoro LNG ("DSLNG"). DSLNG operates the natural gas liquefaction facilities located in Luwuk, Central Sulawesi, Indonesia (the "DSLNG plant"). The DSLNG plant has access to approximately 3,700 bcf remaining gas reserves and has an installed capacity of approximately 2.2 mtpa and a current production capacity of 2.3 mtpa. The LNG from the DSLNG plant is exported to Japan and South Korea under three LNG sales contracts with Chubu Electric Power Co., Inc., Kyushu Electric Power Company, and Korea Gas Corporation. These LNG sales contracts are for an aggregate volume of 1.7 mtpa and are set to expire around 2027.

In November 2017, we signed a gas sales contract with PT PLN (Persero), under which we will distribute gas produced at the Jambaran-Tiung Biru ("JTB") field production unit to PLN until 2035 which may be extended, starting in 2021, with a fixed gas price of US$6.7 per mmbtu.

In order to fulfill domestic LNG demand and develop our international market portfolio, we have secured approximately 4.0 mtpa of LNG by signing long-term LNG sale and purchase agreements with domestic and international LNG producers. We also seek to build relationships with new suppliers in international markets, including Asia, Australia, Papua New Guinea, Africa and the United States, in order to diversify our portfolio of LNG suppliers. In addition, we are working to develop the domestic LNG retail market through the development of small-scale projects for commercial areas, hotels and apartments.

CNG

Our CNG business operations involve the distribution and sale of price-controlled CNG to users of public and private transportation vehicles in Indonesia through CNG refueling stations that we own and operate pursuant to our CNG mandate, as well as the production, distribution and sale of CNG to industrial customers.

Distribution and Sale of CNG under the CNG Mandate

Under our CNG mandate, we construct and operate CNG refueling stations, through which we distribute and sell CNG to users of public and private transportation vehicles under the product name, "EnvoGas." A CNG distribution network comprises mother stations, filling stations that receive CNG from gas producers, daughter stations, filling stations that decant and distribute CNG received from mother stations, and online-gas refueling stations and mobile refueling stations, where CNG is stored and distributed to end-users. The CNG that we distribute is supplied by our upstream business, as well as from third-party domestic suppliers such as Chevron, PHE ONWJ, PHE WMO, PEP, which distributes CNG through pipelines owned and operated by PERTAGAS, and PGN, which we acquired in April 2018. Our first CNG refueling station was completed in December 2012 and our CNG distribution network is comprised of 59 CNG stations (including the Tambak Lorok and Bitung plants). The Government constructs and owns the CNG refueling stations and infrastructure, which we operate on behalf of the Government. Under our CNG mandate, the Government will eventually transfer ownership of the CNG infrastructure assets to Pertamina.

The price at which CNG is purchased and sold is fixed by the Government and we earn a margin from our distribution of CNG. For 2017 and 2018, the price set by the Government for CNG sold to us by our suppliers was US$4.72/mmbtu, and the Government levied an additional toll fee to account for distribution and transportation costs. For 2017 and 2018, the price set by the Government for CNG sold

by us to end-users through our CNG refueling stations was Rp. 3,100 per gasoline-equivalent liter in Jakarta, Bogor, Depok, Tangerang, and Bekasi area and Rp. 4,500 per gasoline-equivalent liter in other areas. As the price set by the Government for CNG sold to us is denominated in U.S. dollars while the price set by the Government for CNG sold by us is denominated in Rupiah, fluctuations in the exchange rate between the U.S. dollar and the Rupiah affect our profit margin from our CNG sales. In 2018, we made a net profit from our CNG sales, but there is no assurance that we will continue to make a profit from our CNG sales if the Rupiah continues to depreciate against the U.S. dollar.

We are currently the only company that has been granted a CNG mandate by the Government.

Production and Distribution and Sale of CNG to Industrial Customers

We produce CNG for distribution and sale to industrial customers in Bitung, West Java, Indonesia. We are using gas produced from the Pondok Tengah field in the PEP block as a source of CNG for distribution and sale to industrial customers. We are also exploring other ways to further expand our CNG business to new customers such as malls, restaurants, hotels and new customers in other industries.

Marketing and Trading

Our marketing and trading activities involve the distribution of fuel, non-fuel and petrochemical products (including LPG and other gas fuels) to both domestic and export markets. Since 2007, we have been appointed by the Government to assist in its efforts to encourage the use of LPG as a substitute for kerosene under the kerosene conversion program. See "— Distribution — Domestic Gas." Our marketing and trading business is organized into three directorates: retail, corporate and logistics (covering shipping and integrated supply chain functions).

We are actively seeking to expand our marketing and trading business. Our key marketing and trading investment projects include:

- the construction and development of fuel terminals pursuant to a ministerial decree in several locations such as Jambi in Tegal, Central Java, Tanjung Batu in East Kalimantan, Maumere in East Nusa Tenggara, Biak in Papua, and in 11 other locations in eastern Indonesia, including Badas, Waingapu, Parepare, Merauke, Ternate, Wayame, Masohi, Bula, Dobo, Labuha, and Namlea. The projects are targeted for completion between 2020 and 2021;

- the replacement of the Cikampek-Plumpang pipeline, which is located between Marunda and Cilincing in North Jakarta. The project is targeted for completion in 2021;

- the development of CB II Lomanis Tasikmalaya, which is located between Lomanis in Central Java and Padalarang in West Java. The project is targeted for completion in 2019;

- the construction of Kertajati Airport at Majalengka in the West Java region, in order to provide aircraft refilling services at the West Java International Airport. The project is targeted for completion in 2019;

- the construction of pressurized LPG tanks at Arun, Aceh, and Pulau Layang in South Sumatera, Belawan in North Sumatera, Dumai, and Balongan in West Java. The projects are targeted for completion between 2019 and 2021;

- the construction and development of the LPG terminal in Eastern Indonesia, including Bima, Kupang, Jayapura, and Wayame. Pursuant to a ministerial decree we will construct and operate the oil fuel and LPG storage tanks in 14 locations in NTB, NTT, Sulawesi South, Maluku, North Maluku and Papua. Construction has commenced in Nusa Tenggara and Papua and targeted for completion between 2019 and 2020;

- the construction of a refrigerated LPG tank at Tj. Sekong in West Java to replace the STS. The project is targeted for completion by the end of 2019;

- the construction of a refrigerated LPG terminal in East Java. The project is targeted for completion in 2022; and

- the construction of new ships, consisting of three mid-size LPG ships and three general purpose ships, which are targeted for delivery by 2020.

In December 2013, we entered into a marketing and trading joint venture agreement with PTT Global Chemical Public Company Limited, Thailand's state-owned petrochemical company, to increase our sale and distribution of polymers in Indonesia. On June 23, 2014, Indo Thai Trading ("ITT") was founded as a joint venture between PT Pertamina Patra Niaga (51.0%) and PTT Chemical International Private Limited (49.0%). We intend to acquire a 100.0% equity interest in ITT through PT Pertamina Patra Niaga, subject to regulatory approval.

Distribution

The table below sets forth sales volume for our refined products for the periods presented.

	For the Years Ended December 31,			For the Three-Month Periods Ended March 31,	
	2016	2017	2018	2018	2019
			(in million KL)		
Motor gasoline[(1)]	21.8	12.5	10.8	2.3	2.9
Kerosene[(1)]	0.6	0.6	0.6	0.1	0.1
Automotive diesel[(1)]	24.5	25.3	27.0	6.2	6.5
Industrial diesel	0.0	0.0	0.0	0.0	0.0
Industrial fuel	1.6	1.4	1.3	0.3	0.3
Aviation turbine fuel	5.2	5.8	6.3	1.5	1.3
LPG[(1)]	12.1	12.9	13.2	3.2	3.3
Refrigerants	0.0	0.0	0.0	0.0	0.0
Lube base oil	0.4	0.4	0.4	0.1	0.1
Petrochemicals and others	4.7	5.6	4.9	1.2	1.1
Total	**70.9**	**64.5**	**64.5**	**14.9**	**15.6**

Note:

(1) All sales of motor gasoline, kerosene, automotive diesel and LPG in 3kg cylinders are pursuant to our PSO mandate. Our LPG in 3kg cylinders sales were 6.0 mt , 6.3 mt, 6.5 mt and 1.6 mt for the years ended December 31, 2016, 2017 and 2018 and the three-month period ended March 31, 2019, respectively. We also sell LPG in 12kg and 50kg cylinders.

The categories for the refined products we distribute are as follows.

Retail Fuel

Our retail fuel business consists of retail fuel sales to end-customers, most commonly through retail fuel filling stations. Our retail fuel sales consist of fuel sold under our PSO mandate (sold under

the brand names "Premium" and "Solar/Biosolar") and non-PSO fuel (sold under the brand names "Premium," "Biosolar," "Pertalite," "Pertamax," "Pertamax Turbo," "Pertamax Racing," "Dexlite" and "Pertamina Dex." See "— PSO" for more information on our PSO mandate.

As of March 31, 2019, there were 6,878 Pertamina-branded retail fuel filling stations in Indonesia. 159 of these retail fuel filling stations are owned and operated by us. The remaining 5,455 retail fuel filling stations are franchise operations, owned and operated by third parties and held for average periods of 20 to 30 years. These service stations are located across Indonesia and exclusively sell gasoline and diesel. All of our retail fuel filling stations share the same branding and are uniform to consumers. The third party dealer pays an initial fee and additional fees on renewal to use our intellectual property rights, including our fuel station design and standard technical specifications, logo and standard operating procedure software management, for the duration of the arrangement. In 2019, we began rolling out cashless payment systems in our Pertamina-branded retail fuel filling stations.

We are actively increasing the number of retail fuel filling stations owned and operated by us to secure our retail distribution network. We currently have 159 of these stations and expect to build approximately 26 more stations owned and operated by us by the end of 2019. We are also actively growing our network of Pertashops, which are smaller-scale Pertamina-branded retail fuel filling stations, to further expand our footprint across the archipelago. We also intend to expand our retail fuel business overseas in the future and have established a representative office in East Timor.

Our market share in relation to subsidized fuel products was 99% for the three-month period ended March 31, 2019 based on BPH MIGAS data, and we estimate our market share in relation to non-subsidized fuel products to be approximately 98%, in 2018. Our main competitors in the retail fuel sector are Shell, AKR and Total.

Industrial and Marine Fuel

Our industry and marine fuel business consists of sales of products such as motor gasoline, kerosene, high speed diesel, industrial diesel oil, industrial fuel oil, marine gas oil and marine fuel oil to commercial customers, whom we supply directly from our depots. Some of our main customers for industry and marine fuel products are PLN, the Indonesian National Armed Forces, the Indonesian National Police, and Contractor Cooperation Contract, in addition to the mining industry, the paper industry, the steel industry and various other industries.

We estimate our market share in relation to industrial and marine fuel to be approximately 71.6% as of December 31, 2018 . Our main competitors in the industry and marine fuel sector are Shell, Petronas, AKR and Petro Andalan.

Aviation Fuel

Our aviation fuel business consists of sales of products such as aviation gasoline and aviation turbine fuel to commercial customers. We supply jet fuel to domestic and foreign airlines at Indonesian airports under the "Avtur" and "Avgas" brands. We have supplied products to more than 100 customers, some of whom are commercial airlines, which represented the majority of our sales volume for aviation fuel in 2018. We distribute aviation fuel through our 68 airport depots in Indonesia and we also supply airline customers through our partners in the Asia-Pacific, the Middle East and Europe.

Non-fuel, Petrochemical and Other Products

Our non-fuel petrochemical and other products include asphalt and bitumen, non-fuel special chemical and biofuel products (such as solvents, green coke, lube base oil, minarex and rubber

processing oil) and petrochemical products (such as paraxylene, benzene, propylene and polypropylene (polytam), sulfur, solvent, rubber processing oil, smooth fluid, petroleum coke and agricultural chemicals). We are also exploring strategic collaborations with third-party suppliers for access to raw materials that can be processed into new and renewable energy products. We market our non-fuel and petrochemical products directly or indirectly through a network of sales personnel and agents dedicated to handling our non-fuel and petrochemical operations for industrial use.

We estimate our market share in relation to non-fuel and petrochemical products to be approximately 51% for bitumen and 41% for aromatic olefin as of March 31, 2019. Our main competitors in the non-fuel and petrochemicals sector are Chandra Asri, Petronas, Shell, Chevron and Esso, and certain other Middle Eastern and Indian producers especially for aromatic and olefin products such as Reliance, Essar Oil, OMPL India, ADNOC and TASWEEQ.

Lubricants

Our lubricant products include automotive engine oils (such as for passenger cars and heavy duty diesel), automotive gear oil, industrial and marine diesel engine oils, circulating oils, hydraulic oils, turbine oils, compressor oils and grease and are marketed under the names, Fastron, Prima XP, Enduro, Mesran, Meditran and Turalik. We market lubricants directly or indirectly through a network of sales personnel and agents dedicated to our lubricant operations that span 24 countries. Our main customers for our industrial lubricant products are mining, power generating, oil and gas, manufacturing and cement companies.

We estimate our market share in relation to lubricants to be approximately 49% as of December 31, 2018. Our main competitors in the lubricants sector are Shell, Castrol, Yamalube, Idemitsu and Repsol, internationally, and in Indonesia we also compete with Federal Oil, Top 1 and Evalube.

We also offer toll blending services in Singapore and Thailand. Toll blending is a specialty service through which we assist companies that require complex lubricant formulations, by mixing and processing the base ingredients for a fee and selling them the final product.

Domestic Gas

Our domestic gas based fuel marketing activities cover products such as LPG, natural gas fuels, refrigerants and aerosol. We sell LPG through agents in 3kg cylinders domestically to households pursuant to our PSO mandate, LPG in 12kg cylinders domestically to households and LPG in 50kg cylinders domestically to hotels and restaurants. We also sell LPG in bulk to end users in the industrial sector. See "— PSO" for more information on our PSO mandate. We sell our gas products under the brand names, Elpiji, Bright Gas, HAP Pertamina and Musicool.

In 2007, we were appointed by the Government to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households. See "— PSO." Since the start of the kerosene conversion program in 2007, we have distributed 65.2 million LPG conversion packages, comprising a stove and a LPG regulator and cylinder. We have distributed a decreasing amount of kerosene in each successive year as a result of the introduction of the kerosene conversion program, as an increasing number of households convert to the use of LPG. We receive compensation from the Government under our PSO mandate for the distribution of subsidized LPG.

PSO

One of our key roles is to distribute subsidized fuel in Indonesia under our PSO mandate. Prior to the passage of the Oil and Gas Law of 2001, we were the sole distributor of subsidized fuel in

Indonesia. After the passage of the Oil and Gas Law of 2001, our monopoly in the downstream sector was originally scheduled to end in November 2005, when private investors (including foreign companies) would be allowed to participate in processing, transporting, storing, distributing and selling refined fuel products. However, on November 15, 2005, the Government announced that our right to sell subsidized fuel had been extended to December 31, 2007 as private competitors, such as AKR and Petronas, did not have the required infrastructure to sell subsidized fuel outside of Java at that time.

Since 2008, the market for subsidized fuel has been opened to competition. Since October 1, 2005, domestic sales of refined products to industrial consumers have no longer been subsidized by the Government and are subject to competitive forces, while only sales of motor gasoline, automotive diesel oil and kerosene for household continue to be subsidized. BPH MIGAS runs an annual tender process and grants licenses for the right to sell subsidized fuel to oil companies, including us. We believe we are positioned favorably to continue to win the PSO mandate given our high market share and fully integrated operations in the downstream sector, particularly because any new company that wishes to distribute fuel is also required to develop retail stations in the underdeveloped areas outside of Java. We participate in an annual tender process for the PSO mandate and have been granted a PSO mandate in each of the last three years. Based on BPH MIGAS data and the amount of subsidized fuel distributed in Indonesia in 2018, we continue to retain 98.3% of the PSO market. We believe this is due to our extensive distribution network. We are also mandated by the Government to assist in its efforts to encourage the use of LPG as a substitute for kerosene in Indonesian households under the kerosene conversion program. We are the sole distributor of LPG in Indonesia.

Under the current PSO system, we first pay for the fuel at market rates, which are typically higher than subsidized rates, which we then distribute at lower regulated prices set by the Government for subsidized fuel products. Subsequently, we receive compensation from the Government through the Minister of Finance in accordance with regulations set by the Minister of Finance and approved by Parliament. The subsidy reimbursement amount for automotive diesel oil is subject to a fixed amount set by the Government. The subsidy reimbursement formula determined by the Government for kerosene distributed under the PSO mandate is based on MOPS's three-month average price for jet kerosene (which is the Oil Fuel Market Index Price for kerosene), less the regulated retail price. Based on MEMR Decree 61/2019, the subsidy reimbursement formula for LPG in 3kg cylinders is based on the benchmark price for the LPG in 3kg cylinders, which is determined by the market index price of LPG in 3kg cylinders (as stipulated by the Government) applicable in the relevant month plus distribution (including handling) costs and margins, less the regulated retail price. The Government sets these compensation formulas annually in conjunction with the setting of the State Budget. The margin is intended to cover transportation and distribution costs. In setting the compensation formulas, the Government makes certain assumptions with respect to the price of crude oil and if the price of crude oil exceeds the price assumed or our transportation, distribution or other costs increase, we may not be able to recover the full costs of distributing subsidized oil products and LPG under the compensation formula and may incur losses as a result. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — PSO Mandate" for more information with respect to the assumptions underlying the compensation formula.

In 2016, 2017, 2018 and 2019, we have received or expect to receive (as applicable) compensation from the Government under our PSO mandate as set forth in the table below.

	Compensation for Production and Distribution of Oil Products	Compensation for Production and Distribution of LPG
2016	Rp. 1,000.0 per liter from January 1, 2016 to June 30, 2016 and Rp. 500.0 per liter from June 1, 2016 to December 31, 2016 for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$68.64/mt + 1.88% CP Aramco + Rp. 1,750.0/kg less the regulated retail price from January 1, 2016 to July 31, 2016, and CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price from August 1, 2016 to December 31, 2016
2017	Rp. 500.0 per liter for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price
2018	Rp. 2,000.0 per liter for automotive diesel oil MOPS + 2.49% of MOPS + Rp. 263.0 per liter less the regulated retail price for kerosene	CP Aramco + US$84.00 /mt + 3.64% CP Aramco + Rp. 1,950.0/kg less the regulated retail price
2019	Rp. 2,000.0 per liter for automotive diesel oil MOPS's average price in the previous three-month period less the regulated retail price for kerosene	103.85% market index price of LPG in 3 kg cylinders (as stipulated by the Government) + US$50.11/mt + Rp. 1,879.00/kg

We and the Government have a framework for subsidy reimbursements. The Government is required to pay us most of the subsidy reimbursements each month based on a submission by us made no later than 10 days after the end of the month. 95% of the subsidy reimbursement submission would typically be made by the Government in the next month from the date of submission of subsidy reimbursements. The remaining 5% of the subsidy reimbursement submission is accumulated and settled quarterly following an audit by the Government. In determining the subsidy reimbursement payable to us in any given month for the distribution of kerosene, the Government's policy is to use MOPS from the month immediately prior to the month which the subsidy reimbursement claim relates to. See Management's Discussion and Analysis of Financial Condition and Results of Operations — PSO Mandate." Also see "Risk Factors — Risks Relating to Our Downstream Operations — We may not be able to pass on increases in costs of our raw materials for products distributed under our PSO or other mandates from the Government or where the prices of such products are fixed at the request of the Government."

In 2017 and 2018, the subsidy reimbursement we received under the PSO mandate on an aggregate basis was sufficient to cover our costs of distribution of LPG in 3kg cylinders. Although crude oil prices had continued to rise and regulated retail sales prices under the PSO mandate continued to be insufficient to cover our costs of producing and distributing those PSO fuel products in 2017 and 2018, the subsidy reimbursements that we received for the distribution of LPG in 3kg cylinders under the compensation formula reduce the shortfall between the retail sales prices and our production and distribution costs for those products and to offset the losses that we incurred for the distribution of other oil products under the PSO mandate.

If crude oil prices exceed the ceiling price assumed by the Government or our transportation, distribution or other costs increase, we may not be able to recover the full costs of distributing subsidized fuel and LPG under the compensation formula and may incur losses as a result.

The Minister of Finance is expected to continue to meet its commitment on subsidy payments due to the national importance of our role in supplying and distributing fuel to Indonesia. In addition, the Government has budgeted Rp. 100,648.44 billion (US$7,067.76 million) for fuel subsidies as reported in the State Budget for 2019.

Trading

Our trading activities include the importing of crude oil and oil products for feedstock at our refineries and for use as domestic fuel and the exporting of (i) the Government's share of crude oil produced; (ii) our crude oil and natural gas that are not used by our refineries; (iii) refined products produced by our refineries, such as LPG, LNG and lubricants and (iii) petrochemicals, such as asphalt and bitumen, paraffin wax, propylene, polypropylene and polyethylene. The types of crude oil that are exchanged include SLC, Minas, Ardjuna, Duri, Cinta, Widuri, BRC, Arun Condensate, and Badak among others. Meanwhile, exported non-fuel and petrochemicals include propylene, green coke, decant oil and others.

See "— Integrated Supply Chain" for more information on our import and export activities.

Shipping

As Indonesia is an archipelago, tankers are required to distribute oil products throughout the country. We have a fleet of vessels to transport oil and gas, and to distribute fuel, non-fuel and petrochemical products to domestic and international markets. The vessels operate across all six of our refinery units and 117 depots.

We operate more than 250 vessels for domestic cargo, of which 65 are owned by us and the rest are chartered. The oil tankers we operate range in size from 1,000 dead weight ton bulk lighters to 105,000 dead weight ton aframax. We also operate several LPG tankers, including our very large gas carriers. Several oil tankers are chartered from PT Pertamina Trans Kontinental and our new shipping subsidiary, PT Pertamina International Shipping. PT Pertamina International Shipping focuses on non-domestic and import and export oil and gas transportation, and it continues to grow in size, as it owns various very large crude carriers, floating storage and offloading and medium range vessels, with approximately 508 thousand dwt in total. The tanker fleet effective carrying capacity, which reflects the maximum amount of cargo that can be carried, is approximately 111.18 million mt. The total cargo size of our fleet, which reflects the amount of cargo which can be shipped, is approximately 133.42 million KL per year and our average effective load factor is approximately 88.3%. We look at average effective load factor as a measure of the effective carrying capacity of the tanker fleet relative to its total cargo size.

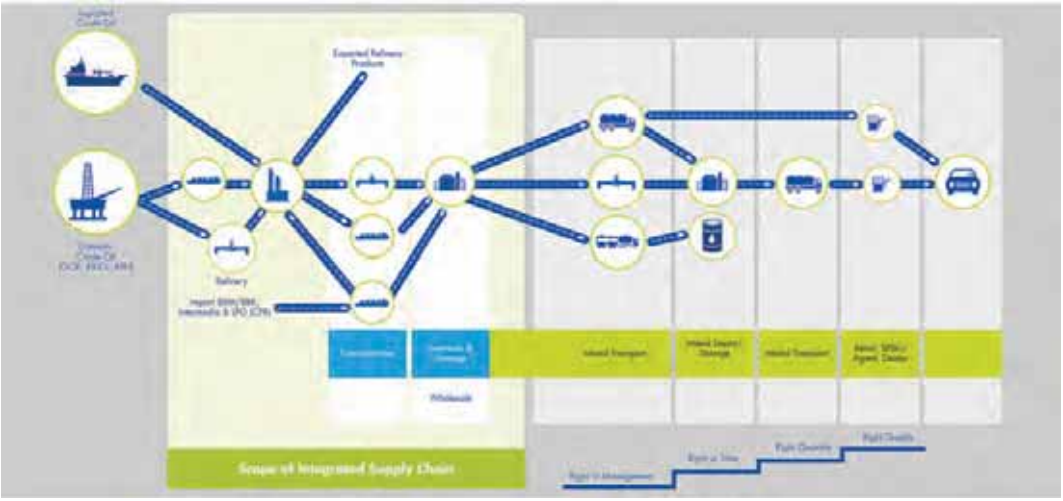
We intend to increase the percentage of the tankers we own from 25% to approximately 50% of our fleet, or 35% to approximately 60% of dead weight ton capacity, and to purchase approximately 52 new vessels by the end of 2026. We plan to retire 22 older vessels by the end of 2026. We also plan to optimize our utilization of tanker tonnage and capacity and to develop and diversify our shipping business beyond owning and chartering oil and LPG tankers, in order to support our supply chain.

We own and manage 107 ports, 169 piers, 13 single-point mooring locations, six ship-to-ship transfer locations, 11 conventional buoy mooring locations and two island berths.

Integrated Supply Chain

The diagrams below illustrate the integration and flow between our upstream, downstream and LNG operations and the role which our integrated supply chain division plays in coordinating our upstream and downstream supply and distribution of feedstock and refined products.

INTEGRATED SUPPLY CHAIN ACTIVITIES



We have an integrated supply chain division to optimize the use of our resources by coordinating our overall refining, marketing and trading activities which is consistent practice among other major integrated oil and gas companies.

Our integrated supply chain division ensures that our refineries have a reliable and consistent source of feedstock by, among other things, buying raw materials to meet their demands and selling any surplus materials they do not need. Our integrated supply chain division works with our marketing and trading division to ensure that our refineries are producing the products that are in demand and to coordinate our import and export requirements. Under Minister of Energy and Mineral Resources Regulation No. 42/2018, we have a right to purchase crude oil from each domestic PSC contractor before such production is exported, and our integrated supply chain division may exercise this right in order to meet our refineries' feedstock requirements. Our integrated supply chain division also gathers and analyzes oil and gas trading market information to ensure that we are able to make informed decisions in our downstream operations. In 2016, we established PT Pertamina International Shipping, which operates a free-on-board cargo transportation business and conducts boat chartering, floating storage offloading and internal cargo optimization functions.

In 2018, our integrated supply chain coordinated the supply of 208.5 mmbbls of domestic crude oil and 339.0 mmbbls of imported crude oil to our refineries and 11 mmbbls of our export products and 200.2 mmbbls of imported products to our marketing division. The value of the imported crude oil and products was US$1.2 billion and US$3.1 billion respectively and the value of the products we exported (which comprises excess refinery products for which there is no domestic demand such as low sulfur waxy residue, naphtha and green coke) was US$1.8 billion. Pricing for domestic crude oil is based on ICP and pricing for imported crude oil and the products which we produced is based on market pricing.

Pricing for domestic crude oil is based on ICP and pricing for imported crude oil and the products which we produced is based on market pricing.

Import of Crude Oil

Although our local crude oil production is significant, crude oil is imported for blending purposes due to different specifications of crude oil required by our refineries.

In the years ended December 31, 2016, 2017 and 2018 and the three months ended March 31, 2019, we imported 150.5 mmbbls or 44.6%, 141.6 mmbbls or 43.0%, 123.0 mmbbls or 37.0% and 19.3 mmbbls or 24.1%, respectively, of the crude feedstock to support our refineries and used domestic sources to provide the balance.

The amount of crude oil we import is dependent on the Government's crude entitlement, which is the amount of crude oil the Government is entitled to receive under production sharing arrangements and cooperation contracts with other oil and gas companies; and which we process on its behalf. We expect to import a lower percentage of crude oil in 2019 as we expect to source sufficient crude oil from domestic producers. Our allocation of crude oil from the Government has increased in line with the Government's policy of encouraging domestic crude oil and condensate lifting from domestic producers. In addition, the Government has issued a new regulation prioritizing the domestic crude oil and condensate entitlement sales.

In 2017, our largest provider of imported crude oil was Saudi Arabia, from which we imported 32.2 mmbbls, or approximately 24% of our total imported crude oil, for our RU IV Cilacap refinery. We sourced approximately 67% of our total imported crude oil under the term supply contract with producers, equity holders, national and multinational oil companies and traders or term supply contracts and the balance under spot contracts.

In 2018, our largest provider of imported crude oil was Saudi Aramco, from which we imported 33.6 mmbbls, or approximately 27.4% of our total imported crude oil, for our RU IV Cilacap refinery. We sourced approximately 49% of our total imported crude oil under the term supply contract with producers, equity holders, national and multinational oil companies and traders or term supply contracts and the balance under spot contracts.

In the three-month period ended March 31, 2019, our largest provider of imported crude oil was Saudi Aramco, from which we imported 6.9 mmbbls, or approximately 33.0% of our total imported crude oil for the period, for our RU IV Cilacap refinery. We sourced approximately 54.0% of our total imported crude oil under the term supply contract with producers, equity holders, national and multinational oil companies and traders or term supply contracts and the balance under spot contracts.

Import of Fuel Products

Our integrated supply chain division coordinates the supply of refined fuel products from our refineries and through imports to our marketing and trading division. The products supplied from our own refineries include gasoline, kerosene, diesel, aviation fuels and LPG. The products we import include gasoline, automotive diesel, high sulfur diesel, aviation fuel and LPG.

As Indonesia's domestic fuel consumption exceeds domestic fuel production, fuel product imports are needed to meet local demand. In 2017 and 2018, our integrated supply chain coordinated the import of following refined fuel products:

	For the Years Ended December 31,	
	2017	2018
	(in mmbbls)	
Motor gasoline	109.5	113.1
Automotive diesel oil (gas oil 0.25% sulfur)	13.3	15.2
Automotive diesel oil (gas oil 0.03% sulfur)	1.2	0.3
Marine fuel oil	0.5	0.2
Aviation turbine fuel	11.8	9.8
LPG	61.05	61.16

Other Businesses

We have subsidiaries and joint ventures through which we hold non-key, non-oil and gas assets and participate in non-core businesses such as domestic non-tanker shipping, a charter airline, insurance and hospital and property management services. Revenues generated from these and other businesses accounted for 1.6% and 3.9% of our total sales and other operating revenues in 2017 and 2018, respectively.

Related Party Transactions

The Government is our sole shareholder and all our transactions with parties related to or owned by the Government constitute related party transactions. These transactions are described in the section titled "Relationship with the Government" included elsewhere in this Offering Memorandum. We sell fuel and other refined products to our related parties, including companies in which we hold a 20.0% to 50.0% interest who are our associates and certain entities with whom we share key management. Our related parties purchase fuel and other refined products from us on arm's-length terms based on market pricing for such fuel and refined products. As of December 31, 2018, trade and other receivables (including subsidy reimbursements due from the Government) owed by our related parties and trade and other payables owed by us to our related parties, including to the Government, comprised 9.6% and 6.1% of our total assets and total liabilities, respectively. As of March 31, 2019, trade and other receivables (including subsidy reimbursements due from the Government) owed by our related parties and trade and other payables owed by us to our related parties, including to the Government, comprised 11.2% and 7.5% of our total assets and total liabilities, respectively. In addition, we share common key management with certain of our related parties.

See Note 41 to our consolidated financial statements, included elsewhere in this Offering Memorandum for more information on our related party transactions.

Competition

We face competition from other oil and gas companies in all areas of our upstream, downstream and gas operations, including the acquisition of production sharing arrangements and cooperation contracts and for sales of oil and gas and refined petroleum products.

Upstream

Major competitors in our upstream oil and gas business in Indonesia and Southeast Asia include international oil and gas companies such as ExxonMobil, INPEX Corporation, Total, ConocoPhilips,

BP and Chevron, many of which are large, well-established companies with greater capital resources and larger teams of operating staff than we have and some of which have been engaged in the oil and gas business for a longer period than us. Such companies may be able to offer more attractive terms when bidding for concessions for exploratory prospects and secondary operations, to pay more for productive natural gas and oil properties and exploratory prospects, and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical or personnel resources permit.

Since the passage of the Oil and Gas Law of 2001, we have had to compete with other Indonesian and international oil and gas companies in tendering for new production sharing arrangements and cooperation contracts. Our ability to acquire production sharing arrangements and cooperation contracts and to acquire, discover, develop and produce reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. However, given the importance of the oil and gas industry to the Indonesian economy, participation by Indonesian companies has been actively encouraged by the Government. For example, the Government has granted partial interests in production areas to regional entities. Being one of the few Indonesian companies involved in the oil and gas exploration and production industry and the only one that is wholly-state owned, we believe that we have certain advantages when seeking to expand our business in this sector, given the depth of our knowledge and experience of the exploration and production environment in Indonesia and our long-standing relationship with the Government.

We are the main player in the geothermal industry in Indonesia. Until 2011, we own-operated or joint-operated all geothermal plants in Indonesia. In 2011, we transferred our ownership interests in PT Geo Dipa Energi to the Government and now compete against it with respect to the allocation of geothermal working areas and projects. Other companies involved in the geothermal industry include PT Geo Dipa Energi, Chevron, Star Energy, Bumigas Energi and Medco Energi, among others.

Downstream

We are currently the largest refiner in Southeast Asia by refining capacity and we are the dominant refining company in Indonesia, wholly owning and operating six of the nine active oil refineries in Indonesia, according to Wood Mackenzie. Our refining operations compete with other domestic and international suppliers for sales of refined petroleum products both inside of Indonesia and abroad. International suppliers include Petronas, PTT, Petron, ExxonMobil, Shell, Chevron, Singapore Refining Company and PetroVietnam.

According to Wood Mackenzie, we are the only company which has full value chain integration in the downstream marketing business.

Our retail fuel business primarily competes with Shell, AKR and Total, as well as independent operators in the commercial and retail markets, for the sale of refined petroleum products.

Market participants compete primarily on the basis of price, proximity to customers, brand name, quality, services offered and efficiency. Because margins on the sale of motor gasoline and automotive diesel oil are very low, competition has developed for higher margin products that can be sold at service stations, including high margin oil products such as lube and gasoline additives and non-oil goods and services. We cannot assure you that we will be able to maintain our leading market position in Indonesia or that our service stations will remain competitive in the retail petroleum industry.

Further, our role as the sole provider of fuel under the PSO mandate is now open to competition. Since 2008, BPH MIGAS has run a tender process for the PSO mandate and grants licenses to oil

companies to sell subsidized fuel. In each of the last three years, AKR was also granted a PSO mandate by the Government. Based on the total amount of subsidized fuel distributed in Indonesia, we had 98.2% of the PSO market in each of 2016, 2017 and 2018. We believe this is due to our widespread distribution network, but we expect competition to intensify as our competitors build the necessary infrastructure. See "— PSO" for more information on our PSO mandate.

Our main competitors in the industry and marine fuel sector are Shell, Petronas, AKR and Petro Andalan, who are actively and aggressively building infrastructure across Indonesia for greater delivery capacity.

We are the market leader of the aviation fuel sector in Indonesia. In the past, we have been the sole provider of aviation fuel in Indonesia. The Government announced in March 2019 that it has granted a temporary permit to a private company to set up operations to sell jet fuel.

We are the market leader of the CNG sector in Indonesia and we do not currently have competitors in this sector.

In our petrochemicals segment, we compete domestically with Chandra Asri, Petronas, Shell, Chevron and Esso.

As we distribute lubricants both domestically and in over 24 countries and multiple regions around the globe, including Asia, Australia and the Middle East, we face competition in this sector from both local competitors such as Federal Oil, Top 1 and Evalube and international competitors such as Shell, Castrol, Yamalube, Idemitsu and Repsol.

Properties

In addition to the upstream and downstream oil and gas assets described above, our major properties include natural gas pipelines, land and buildings, machinery and equipment including tankers, oil terminals, gas service stations, gas separation plants and other fixed assets used for exploration and production of petroleum.

Our headquarters are located at Jl. Medan Merdeka Timur No. 1A, Jakarta.

Nearly half of our land assets by area are not owned free and/or clear. "Free" means that we have all legal documents required to prove our title to a land asset. "Clear" means that we have physical control over a land asset, *i.e.* there are no third parties either occupying the land or disputing our ownership of the land asset. Our non-free and non-clear assets as of each of December 31, 2018 and March 31, 2019 are valued at US$112.2 million, without taking into account any provision for impairment. See "Risk Factors — Risks Relating to Our Company — We do not have free and clear title to a significant portion of our land assets" for more information on this issue.

Research and Development

In July 2017, we established the RTC to manage research activities in Pertamina and address challenges in increasing technological capabilities in both downstream and upstream technologies. The RTC combines our previously-separate upstream and downstream research and development institutes and serves as an integrated research and development center that is expected to generate technology so as to improve production output and efficiency, formulate technological strategies to meet our current and future needs and to enhance our technological capabilities. We are also developing research related to new and renewable energy. We believe that the RTC can develop a wide range of technological innovations, products or processes intended to address our future energy challenges.

In the upstream sector, the RTC focuses on five areas of research and development, namely exploration research, development research, production research, drilling and well construction research and geothermal research. Upstream technological development is mainly directed towards the discovery of new reserves that are increasingly difficult to come across and the production of unconventional oil and gas by developing technologies relating to enhanced oil recovery (surfactants, CO2, polymers and chemicals), drilling for exploration and exploitation, unconventional petroleum (coal bed methane, shale gas and oil sand) and exploration into deep water and harsh environments.

In the downstream sector, the RTC focuses on four areas of research and development, namely oil and gas research, process development research, materials and chemical research and petrochemical and petroleum non-fuel research. This research helps to develop new oil- and gas-based products.

In the new and renewable energy sector, the RTC focuses on four areas of research development, namely renewable energy development research, new energy development research, power development and storage management research and carbon capture and storage research. We prioritize research on biofuels, especially those based on agricultural products, algae wastes and biomass. Our other research relates to other new and renewable energy, such as solar and coal gasification, and the development of power storage and carbon capture technology.

Our actual expenditures for research and development were US$5.2 million for 2017 and US$4.2 million for 2018. Approximately US$6.0 million is budgeted for our upstream research and development activities in 2019, of which US$0.3 million had been spent as of March 31, 2019.

Trademarks and Service Marks

We have trademarked certain of our product names to protect our various brands in both the domestic and international market. In relation to our retail fuel business, we have trademarks for our wholly -owned and run retail fuel products; for instance, “Pertalite,” for one of our value-added, non-PSO retail fuels, “Fastron,” “Prima XP,” for our lubricant products and “Musicool and “HAP Pertamina” for our gas products. The relevant Certificate of Trademark for several of our trademarks, including “Dexlite,” “Pertamax Turbo,” “Pertamina Racing,” and “Bright Gas” are pending. We have not had any significant disputes with respect to any of our trademarks or service marks. We currently hold several patents for our products or processes.

Insurance

We have comprehensive insurance policies that cover our business, our properties and litigation brought by third parties. We employ a risk management policy for purposes of analyzing the risks faced by our businesses in determining the appropriate insurance coverage. Our coverage includes onshore & offshore property insurance, marine hull & machinery insurance, land rigs insurance, cost of well control insurance, pipelines insurance, third party liability insurance, project insurance, directors & officers liability insurance, marine cargo insurance, refueling liability insurance and protection & indemnity insurance. We consider our insurance coverage to be in accordance with industry standards.

In respect of our exploration and production, refining, petrochemical production, and marketing and sales operations, we currently maintain insurance policies with a domestic Indonesian insurer, Tugu Group, in which we hold an interest through our subsidiary, PT Asuransi Tugu Pratama Indonesia. Approximately 42% of our property insurance coverage is reinsured through Lloyd’s of London, while the remainder is retained by Tugu Group.

See "Risk Factors — Risks Relating to Our Upstream Operations — Oil, gas and geothermal operations are subject to significant operating risks hazards, for which we may not be fully insured" for risks relating to our insurance.

Health and Safety

We are subject to various health and safety laws. We have extensive safety procedures designed to ensure the health and safety of our workers and assets, the public and the environment. A safety manual of detailed operating procedures is available at the operations level, with another, more specific, manual maintained by each of our operating subsidiaries, which together govern these safety procedures. Certain procedures must be approved by a safety officer in advance before they can be undertaken, and in the event of any accidents or fatalities, we have procedures in place to investigate such incidents and determine if compensation would be necessary.

Our Health, Safety and Environment ("HSSE") board committee is responsible for drafting our HSSE policies and procedures. Our Senior Vice President of HSSE Corporate is responsible for the overall implementation of the HSSE policy and the coordination of all HSSE activities throughout our Company. The Senior Vice President of HSSE Corporate in turn reports to the President Director or Chief Executive Officer. Further, we have in-house HSSE teams present in each of our business units, subsidiaries and locations where we operate, to ensure that our HSSE policies are followed in each respective location. The HSSE teams in each location report either to the operational head or general manager of each location and for each directorate represented by the Vice President of HSSE, as applicable, who in turn coordinate with the Senior Vice President of HSSE Corporate.

It is our policy that in the event of any conflict between the progress of work and health or safety concerns, the health and safety of employees, equipment and third parties are paramount. We provide our employees with comprehensive training in safety related matters. Government officials make both scheduled and random checks at our operating facilities to ensure that safety procedures are being followed. We have also implemented a contractor safety management system to ensure accountability of our contractors and reduce the worksite incident and injury rates.

Employees

The following table provides a breakdown of our Company's (including PGN's) employees as of the dates indicated.

	As of December 31,			As of March 31,
Unit	**2016**	**2017**	**2018**	**2019[1]**
Upstream	203	176	181	177
Downstream	9,058	8,926	9,099	9,588
Gas	164	145	—	—
Integrated supply chain	100	110	122	116
Administration (including top management, corporate secretary and human resources)	1,362	1,145	1,378	1,408
Finance, treasury and accounting	776	1,002	985	977
Company total	**11,663**	**11,504**	**11,765**	**12,266**
Subsidiaries total	**17,806**	**18,614**	**20,674**	**15,934**
Total (Company and subsidiaries)	**29,469**	**30,118**	**32,439**	**28,200**

Note:

(1) Excludes PGN.

In addition to our full-time employees, we also rely on outsourced labor. We hire outsourced labor through a labor service agreement with labor supply companies. Wages and benefits, terms of employment and dispute settlement mechanisms for outsourced employees are determined by agreement between the employees and the labor supply company, subject to labor regulations.

All full-time employees involved in oil and gas exploration and production are our employees or employees of our operating subsidiaries. Our upstream human resource management policies are subject to oversight by SKK MIGAS. SKK MIGAS reviews our upstream personnel plans to ensure that they remain in accordance with development plans for PSC.

A substantial number of our employees are unionized. 19 of our labor unions form a federation (*Federasi Serikat Pekerja Pertamina Bersatu*) that covers 8,757 employees registered as members. We consider our relationship with the federation to be good. The rights and responsibilities under our relationship with the unions are formulated in a collective labor agreement (*Perjanjian Kerja Bersama*) between the unions and our Company which is registered with the Ministry of Manpower of Indonesia. Our latest collective agreement with the unions was signed April 2019 and is valid for two years. To date, we have not had material issues in procuring or renewing collective labor agreements.

We have not been subject to any material strikes or other labor disturbances that have interrupted our operations. We believe our relationship with our employees is good. However, see "Risk Factors — Risks Relating to Indonesia — Labor activism and unrest may materially and adversely affect us."

Certain of our employees, including all of our management, are not members of any labor union, and have not entered into collective bargaining agreements. We believe our relationship with these employees is good.

The total take-home pay of our employees includes base salary, allowances based on the location where the employee works, allowances for an employee's position and/or sales and income tax allowances. We further provide certain of our employees other cash allowances and incentives (including holiday allowances, annual leave allowances and our annual incentive plan), health benefits, leave benefits, retirement benefits (including severance bonuses, pension plans, saving plans, life assurance and mandatory government insurance) and facilities (including housing, club memberships and car and phone services).

In accordance with applicable Indonesian regulations, we currently participate in pension contribution plans organized by municipal and provincial governments, under which we contribute at an average rate of 10.0% of our employees' salaries, bonuses and certain allowances. The contributions vary from region to region. Other than the contributions, we have no other material obligation for the payment of pension benefits associated with these plans. We also provide retirement benefits based on the retirement base income and the respective employment period. Retirement benefits are provided from the fund on a monthly basis to the former employee on the basis of a contributory program. Contributions are made by us and the employee to the program during the employment period based on the rules of the retirement fund.

Other retirement benefits that an employee receives and that are funded by us include a post-employment benefit amount and health care benefits. Each employee also participates in a retirement training program shortly before retirement.

We also provide certain health care benefits to our employees and their families. Health care benefits include in-patient and out-patient treatments, glasses, and dental and periodic medical check-ups.

We have a number of training and education programs for our employees. We classify our training and education programs into three categories: generic training, technical training and overseas training. Generic training is available to all employees and ranges from leadership and managerial topics such as courses on good corporate governance and our executive development program to corporate culture. Technical training is specific to each department and includes courses for specialists within each department. Examples of technical courses which we run include courses on "Advanced Process Design" and "Logistics" in our refinery business unit and out general and human resources business unit respectively. Overseas training is available to all employees and is conducted on an ad hoc basis.

Environmental Matters

Our oil and gas exploration and production operations, petroleum and petrochemical products and other activities are subject to Indonesian laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws include the New Environmental Law and other regulations relating to hazardous wastes, emissions and effluent waste water management. These laws and regulations may require the acquisition of a permit before drilling or refining commences, which may restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, require remedial measures to prevent pollution resulting from the former operations, such as plugging abandoned wells, and impose substantial penalties for pollution resulting from our oil, natural gas and petrochemical operations. We may also be required in certain situations to complete environmental impact analyses and to enter into various environmental management undertakings prior to carrying out exploration and development operations, production and refining activities. These environmental management activities are regulated by the Ministry of Energy and Mineral Resources and Ministry of Environment and Forestry.

The New Environmental Law introduced an environmental permit (*Izin Lingkungan*) and requires that all licenses regarding environmental management issued by the Government must be integrated with the environmental permit requirements within a year of the enactment of the law. On February 12, 2012, the Government enacted Regulation No. 27 which requires companies which are required to obtain an AMDAL approval or prepare a UKL and UPL to also be obliged to obtain the environmental permit in order to obtain a business license but all permits and licenses existing before implementation of Regulation No. 27 would be accepted as valid environmental permits. We have taken steps to improve our management of sludge and drilling waste in order to comply with the standards set by the New Environmental Law. See "Risk Factors — Risks Relating to Our Company — Our compliance with or breach of environmental regulations in Indonesia and in the countries in which we operate could materially or adversely affect our business, financial condition, results of operations and prospects."

Under Indonesian environmental regulations, remedial and preventative measures, as well as sanctions (such as the imposition of substantial criminal penalties, fines and the cancellation of concessions) may be imposed in order to remedy or prevent pollution caused by operations. Such sanctions range from one to 15 years of imprisonment for any person who has caused environmental pollution or environmental damage, and fines ranging from between Rp. 500 million to Rp. 15 billion, subject to an additional penalty of one-third of the fine amount if the person directs a corporate entity to commit a breach of the New Environmental Law. The Ministry of Environment and Forestry also reserves the right to impose a monetary penalty in lieu of any rehabilitation obligations of a liable person.

The environmental management systems that apply to us are EMS ISO 14001 and Environmental Compliance Performance Evaluation Program (*Program Penilaian Peringkat Kinerja Perusahaan dalam Pengelolaan lingkungan*, or "PROPER") administered by the Ministry of Environment and Forestry.

EMS ISO 14001 is a voluntary standard that requires organizations to put in place and implement a series of practices and procedures that, when taken together, result in an environmental management system. Approximately 80% of our fields, refineries, geothermal areas and marketing and trading centers meet EMS ISO 14001 standards and certifications.

The Ministry of Environment and Forestry in Indonesia rates companies in accordance with PROPER, which consists of a series of five ratings ranging from "gold" (the highest possible rating) to "black" (the lowest possible rating). This rating program is conducted for every business and/or activity with potential to create pollution and/or environmental damage. Companies in Indonesia that are rated on the PROPER program are required to publicly disclose their level of compliance.

As of December 31, 2018, 14 of our unit operations have gold PROPER ratings (indicating excellent compliance levels), 69 of our unit operations have green PROPER ratings (indicating that they are beyond compliance levels), and 78 of our unit operations have blue PROPER ratings (indicating they are fully compliant). As of December 31, 2018, two of our operating units that had blue PROPER ratings during the July 2017 to June 2018 appraisal period had received a red PROPER rating, which indicates the units are partially out of compliance due to a lack of monitoring activities at various locations. We took immediate steps to improve monitoring activities at these two operating units in accordance with the requirements of the Ministry of Environment and Forestry. At both operating units, domestic waste water quality monitoring has been conducted every month since July 2018, sea water quality monitoring was conducted at the required points in July and August 2018 and in January 2019. The results of measurements at both operating units indicated that the quality of domestic wastewater and sea water are below the threshold value set by the Government. We believe that the steps that we have taken will result in an upgrade of these two operating units to at least blue PROPER ratings during their next assessment period, which is scheduled for July 2018 until June 2019. The results of the assessment will be announced at the end of 2019.

Various environmental laws, rules and regulations may act to limit the rate of oil and natural gas production to levels below the rate that would otherwise exist. These laws and regulations may also restrict air emissions and discharges to surface and subsurface water resulting from the operation of natural gas processing plants, chemical plants, refineries, pipeline systems and other facilities that we own. In addition, our operations may be subject to laws and regulations relating to the generation, handling, storage, transportation, disposal and treatment of waste materials. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal and clean-up requirements could have a significant impact on our operating costs, as well as the oil and gas industry in general.

The Government has imposed environmental regulations on oil and gas companies operating in Indonesia and in Indonesian waters. Operators are prohibited from allowing oil into the environment and must ensure that the area surrounding any onshore well is restored to its original state insofar as this is possible after the operator has ceased to operate on the site. An environmental impact study and a Government permit are required before any exploration work can commence. Under the Oil and Gas Law of 2001, SKK MIGAS has direct control over upstream operators to ensure that they meet Government regulations. We are required to provide a report containing an environmental impact analysis to the Indonesian environmental agency at least two times a year. For certain areas, we are currently in the process of installing additional equipment in our producing fields to comply with the New Environmental Law. For details of the risks that we face if this deadline is not extended, see "Risk Factors — Risks Relating to the Oil, Gas and Geothermal Industry — Our compliance with or breach of environmental regulations in Indonesia and in the countries in which we operate could materially adversely affect our business, financial condition, results of operations and prospects."

Our management believes that we are in compliance with current applicable environmental laws and regulations in all material respects and that continued compliance with existing requirements will

not have a material adverse impact on us. See "Risk Factors — Risks Relating to the Oil, Gas and Geothermal Industry — Our compliance with or breach of environmental regulations in Indonesia and in the countries in which we operate could materially and adversely affect our business, financial condition, results of operations and prospects."

Legal Proceedings

We are involved in certain judicial and arbitral proceedings before Indonesian courts or arbitral bodies concerning matters arising in connection with the conduct of our business in the ordinary course.

We believe, based on currently available information, that the results of our legal proceedings, in the aggregate, will not have a material adverse effect on our financial condition or operations.

MANAGEMENT

In accordance with Indonesian law, we have both a Board of Commissioners and a Board of Directors. The two boards are separate and no individual may serve as a member on both boards.

The rights and obligations of each member of the Board of Commissioners and Board of Directors are regulated by our articles of association and by the decisions of our shareholder in general meeting. Under our articles of association, the Board of Directors must consist of one or more members, one of which will be appointed as the President Director and the other one will be appointed as Vice President Director. Any of the President Director, the Vice President Director or one of the Directors (in the event the President Director and Vice President Director are unavailable, and as appointed in writing by the President Director) is entitled to act for and on behalf of our Company, provided that their actions have been approved in the meeting of Board of Directors. If there is no such written approval, the Director who has had the longest term of office may act on our behalf. The Board of Commissioners must consist of one or more Commissioners, one of which will be appointed as the President Commissioner.

Board of Commissioners

The principal function of the Board of Commissioners is to supervise the policy of the Board of Directors in connection with our business activities and to give advice to the Board of Directors in accordance with our articles of association, shareholder resolutions and prevailing rules and regulations.

Members of the Board of Commissioners are appointed and removed at a shareholder's general meeting shareholders and generally serve five-year terms. The Board of Commissioners comprises seven members.

The following table sets forth certain information concerning the current members of the Board of Commissioners.

Name	Position	Age	Appointed Since
Tanri Abeng	President Commissioner and Independent Commissioner	77	May 2015
Arcandra Tahar	Vice President Commissioner	48	November 2016
Ego Syahrial	Commissioner	56	May 2018
Gatot Trihargo	Commissioner	59	April 2019
Suahasil Nazara	Commissioner	48	May 2015
Alexander Lay	Independent Commissioner	45	September 2017

Tanri Abeng was appointed to our Board of Commissioners in May 2015 and is currently President Commissioner and Independent Commissioner. Mr. Abeng served as Minister at the Ministry of State Owned Enterprises, as a Member of Council on Stabilization of Economic & Financial Resilience, and as Finance Director at PT Union Carbide Indonesia. He also worked for Heineken (Netherlands), Bakrie & Brothers, and held several non-executive positions in other companies, including BAT (UK) from 1995 to 1998, BATA (Canada) from 1993 to 1998, and Asia Pacific Breweries (Singapore) from 1981 to 1991. He was a Member of the Indonesian People's Consultative Assembly from 1993 to 1998, President Commissioner of PT Telkom from 2004 to 2010, Publisher of Globe Asia, President Commissioner of PT Alcatel-Lucent Indonesia, member of the Board of Commissioners of Lippo Karawaci from 2010 to 2016), and he founded Tanri Abeng University in 2011. Mr. Abeng graduated from the State University of New York in Business Administration. He completed the Advanced Management Program at Claremont Graduate School in the United States in 1984 and received his Doctorate degree from Gadjah Mada University in 2010.

Arcandra Tahar was appointed to our Board of Commissioners in November 2016 and is currently Vice President Commissioner. Mr. Tahar also serves as a Deputy Minister within the Ministry of Energy and Mineral Resources, a position he has held since October 2016. Mr. Tahar's career includes positions as research assistant at the Offshore Technology Research Center from 1997 to 2001, technical advisor at Noble Denton, and researcher at Technip Offshore from 2001 to 2006. He worked at Hydronynamics Lead FloaTEC LLC from 2006 to 2007 and served as Principal and President of Asia Pacific AGR Deepwater Development System from 2007 to 2009, Principal Horton Wilson Deepwater from 2009 to 2013 and President of Petroneering from 2013 to 2016. He was also Indonesia's Minister of Energy and Mineral Resources from July 2016 to August 2016. Mr. Tahar graduated from the Department of Mechanical Engineering at the Institute of Technology Bandung in 1994. He received a Bachelor's Degree and a Doctoral Degree in Ocean Engineering from Texas A&M University in 1998 and 2001, respectively.

Ego Syahrial was appointed to our Board of Commissioners in May 2018. He previously served as Head of the Geological Agency, as Head of Bureau of Planning and Cooperation of EDSM, as Head of the Data and Information Center (Pusdatin), as Director General of Oil & Gas, and as Secretary General of the Ministry of Energy and Mineral Resources. He received his Bachelor's Degree in Petroleum Engineering from Trisakti University and his Doctor of Philosophy from the University of London.

Gatot Trihargo was appointed to our Board of Commissioners in April 2019. Mr. Trihargo was born in Jogjakarta on August 29, 1960. He was appointed as Commissioner of PT Pertamina (Persero) in April 29, 2019 by the Decree of the Minister of State Enterprises No.SK-86/MBU/04/2019 dated April 29, 2019 at the General Meeting of Shareholders PT Pertamina (Persero). He received his Bachelor of Accounting from the State College of Accountancy in 1989 and a Master's degree in Accounting and Financial Information System (MAFIS) from Cleveland State University in 1993.

Suahasil Nazara was appointed as a Commissioner in May 2015. His career began as a lecturer at the Faculty of Economy and Business at the Universitas Indonesia (FEB-UI) in 1999. Mr. Nazara earned a Professorship in Economics in 2009. He has held several positions, including Head of Postgraduate Program of Economics Science from 2004 to 2005, Head of the Demography Institution from 2005 to 2008, and Head of the Economics Science Department from 2009 to 2014. In addition, Mr. Nazara is also active in assisting the Government of Indonesia in various capacities. Among them are his membership of the Assistance Team for the Minister of Finance of the Fiscal Decentralization Sector, which he held from 2008 to 2011. He was also a Working Group Coordinator of the National Team Secretary Policy on Poverty Reduction Acceleration, a Member of the Secretariat at the Vice President's Office of the Republic of Indonesia from 2010 to 2015, and a Member of the National Economic Committee or KEN from 2013 to 2014. Since February 2015, he was appointed as Acting Executive Head of the Fiscal Policy Agency at the Minister of Finance and since October 2016 he has also served as Head of Executive for the Fiscal Policy Agency at the Minister of Finance of Indonesia. Mr. Nazara earned his Bachelor of Economics Degree from the Universitas Indonesia in 1994, his Master of Science Degree from Cornell University in 1997, and earned his Doctorate Degree from the University of Illinois at Urbana Champaign in 2003.

Alexander Lay was appointed to our Board of Commissioners in September 2017. Mr. Lay held positions as Drilling Services Engineer at Schlumberger Oilfield Services (Anadrill) from 1997 to 1999, as Senior Associate at Lubis, Santosa & Maulana Law Firm from 2006 to 2009, as Founding Partner of Lasut, Lay & Pane Law Office from 2009 to 2014, as Special Staff for Legal Affairs for the Secretary of the Cabinet of the Republic of Indonesia in 2015, as Commissioner of PT Asuransi Jasa Indonesia (Persero) from September 2016 to September 2017, and as Special Staff of Legal Affairs for the Minister of the State Secretariat since September 2015. Alexander Lay graduated with a degree in Petroleum Engineering from the Bandung Institute of Technology in 1997, attended the Law School of Atmajaya University in Jakarta in 2003, and obtained his Master of Law Degree from the University of Sydney in Australia in 2006.

Board of Directors

Members of the Board of Directors are elected for five-year terms at a shareholder's general meeting. The Board of Directors is comprised of a President Director and Chief Executive Officer and eight other Directors. The Board of Directors is responsible for the management of our business.

The following table sets forth certain information concerning the current members of the Board of Directors.

Name	Office/Division	Age	Appointed Since
Nicke Widyawati	President Director	51	August 2018
Dharmawan H. Samsu	Upstream Director	54	August 2018
Budi Santoso Syarif	Refinery Director	55	April 2018
Basuki Trikora Putra	Corporate Marketing Director	56	April 2018
Mas'ud Khamid	Retail Marketing Director	54	April 2018
Pahala N. Mansury	Finance Director	48	September 2018
Gandhi Sriwidodo	Logistic, Supply Chain and Infrastructure Director	55	April 2018
Ignatius Tallulembang	Refinery and Petrochemical Megaproject Director	56	September 2018
Heru Setiawan	Investment Planning and Risk Management Director	55	September 2018
Koeshartanto	Human Resources Director	58	August 2018
M. Haryo Yunianto	Asset Management Director	49	April 2018

Nicke Widyawati was appointed as our President Director in August 2018. Her career started in 1988 as Assistant Bank Account Manager in Bandung. Prior to serving as the Human Resources Director of Pertamina, Nicke served as the Director of Strategic Procurement at PT PLN (Persero). She graduated from the Bandung Institute of Technology in Industrial Engineering in 1991 and obtained her Master of Business Law Degree from Padjadjaran University in 2009.

Dharmawan H. Samsu was appointed as Upstream Director in August 2018. Prior to his appointment he served as Head of Country at BP Indonesia. He graduated with a degree in Geophysics Engineering from the University of Indonesia.

Budi Santoso Syarif was appointed as Refinery Director in April 2018. Prior to this appointment, he served as our Senior Vice President for Refining Operations. He graduated from the University of Indonesia and holds a Master of Industrial Engineering Degree and a Graduate Certificate in Industrial Engineering Management from Queensland University of Technology in Australia. He also graduated with a degree in Chemical Engineering from Gajah Mada University.

Basuki Trikora Putra was appointed as the Corporate Marketing Director in April 2018. Prior to this appointment, he served as our Senior Vice President for Non-Fuel Marketing. He graduated with a Bachelor's Degree in Mechanical Engineering from Trisakti University.

Mas'ud Khamid was appointed as the Retail Marketing Director in April 2018. Prior to this appointment, he served as Consumer Service Director at Telkom Indonesia. Mr. Khamid obtained a Bachelor's Degree in Physics Engineering from the Sepuluh Nopember Institute of Technology in 1989. He also graduated from the Senior Executive Program and Global Leadership Program at Northwestern University's Kellogg School of Management in Chicago in 2006 and 2009, respectively. Mr. Khamid also completed the Executive Education Program at Harvard Business School in 2015.

Pahala N. Mansury was appointed as Finance Director in September 2018. He previously served as President Director of PT Garuda Indonesia (Persero) Tbk from 2017 to 2018, as Senior Consultant at Booz Allen Hamilton, and as Project Leader at the Boston Consulting Group until 2003. He graduated from the Faculty of Economics at the University of Indonesia and obtained a Master of Business Administration Degree from New York University's Stern School of Business.

Gandhi Sriwidodo was appointed as Logistic, Supply Chain and Infrastructure Director in April 2018. His career with our Company began in 1991 and has held various positions, including President Director of PT Pertamina Patra Niaga. He graduated with a degree in Chemical Engineering from Diponegoro University in 1989 and obtained his Master's Degree in Management and Marketing from Hasanudin University in 2003.

Ignatius Tallulembang was appointed as Refinery and Petrochemical Megaproject Director in September 2018. Prior to this appointment, he served as Commissioner of PT Pertamina Lubricant and as Senior Vice President in our Project Execution, Refinery and Petrochemical Megaprojects Directorate. He holds a Bachelor's Degree in Chemical Engineering from Gajah Mada University.

Heru Setiawan was appointed as Investment Planning and Risk Management Director in September 2018. Prior to this appointment, he served as our Refinery and Petrochemical Megaproject Director. He graduated in degree in Mechanical Engineering from the Bandung Institute of Technology and obtained his Master in Business Administration Degree from the University of Montreal in Canada.

Koeshartanto was appointed as Human Resources Director in August 2018. He previously served as Human Resources & General Affairs Director at PT Jasa Marga (Persero) Tbk. He graduated with a Bachelor's Degree in Economics from Diponegoro University in 1985 and earned his Master of Business Administration Degree from IPMI Business School.

M. Haryo Yunianto was appointed as Asset Management Director in April 2018. Prior to this appointment, he served as President Director of PT Patra Jasa. He graduated with a Law Degree from the Islamic University of Indonesia and received his Master of Management Degree from the Veteran National Development University of Jakarta.

Senior Management

The following table sets forth certain information concerning our senior management.

Name	Office/Division	Age	Appointed Since
Nicke Widyawati	President Director	51	August 2018
Hasto Wibowo	Senior Vice-President, Integrated Supply Chain	52	November 2018
Aji Prayudi	Chief Legal Counsel & Compliance	55	July 2018
Faisal Yusra	Chief Audit Executive	55	September 2017
Dharmawan H. Samsu	Upstream Director	54	August 2018
Budi Santoso Syarif	Refinery Director	55	April 2018
Basuki Trikora Putra	Corporate Marketing Director	56	April 2018
Mas'ud Khamid	Retail Marketing Director	54	April 2018
Pahala N. Mansury	Finance Director	48	September 2018
Gandhi Sriwidodo	Logistic, Supply Chain, & Infrastructure Director	55	April 2018
Ignatius Tallulembang	Refinery & Petrochemical Megaproject Director	56	September 2018
Heru Setiawan	Investment Planning & Risk Management Director	55	April 2018
Koeshartanto	Human Resources Director	58	August 2018
M. Haryo Yunianto	Asset Management Director	49	April 2018

Nicke Widyawati. See "— Board of Directors."

Hasto Wibowo was appointed as our Senior Vice-President, Integrated Supply Chain in November 2018. His career with our Company began in 1992 in the Lubricant Business Unit of our Marketing & Trading Directorate. Since then, he has held various positions with our Company, including General Manager of Operation Regional III in Western Java, and with our subsidiaries, including Chief Executive Officer of Patra Niaga, Chief Executive Officer of PT Indo Thai Trading, Vice President of Crude, Trading & Commercial — Pertamina Integrated Supply Chain and Vice President of Strategic Planning & Business Development — Pertamina Logistic Supply Chain & Infrastructure. Mr. Wibowo received his Bachelor's Degree in Chemical Engineering from the Bandung Institute of Technology in 1991 and Master's Degree in Mechanical Engineering from the University of Indonesia in 2000.

Aji Prayudi was appointed as our Chief Legal Counsel & Compliance in July 2018. He has 28 years of experience working in our legal department. He has held various positions with our Company, including Vice President of Legal & Relation at PT Pertamina EP from 2013 to 2014, Vice President of Legal Counsel Upstream & Gas at PT Pertamina (Persero) from 2014 to 2017 and Vice President of Relations at PT Pertamina Hulu Energi from 2017 to 2018. He achieved a Bachelor's Degree in Civil Law from the University of Indonesia and obtained two Master's Degrees in Management from Gadjahmada University, Yogyakarta and a Master of Law Degree from University of Indonesia, Jakarta.

Faisal Yusra was appointed as our Chief Audit Executive in September 2017. His career with our Company began in 1989 as an Electrical Drawing Staff at the Kalimantan Regional Processing Unit. Since then, he has held various positions with our Company, including Assistant Manager at the Operational System Development Fuel Refinery Directorate of Processing, Assistant to the Contract Manager for the Integrated Supply Chain, Quality Management Manager and Vice President of Quality, System & Knowledge Management at Pertamina. He received his Bachelor's Degree in Electrical Engineering from the University of North Sumatra in 1987, attended the Law School of Tridharma University, and is a Balikapan and S2 Postgraduate of Economics at the General Sudirman University in 2001.

Dharmawan H. Samsu. See "— Board of Directors."

Budi Santoso Syarif. See "— Board of Directors."

Basuki Trikora Putra. See "— Board of Directors."

Mas'ud Khamid. See "— Board of Directors."

Pahala N. Mansury. See "— Board of Directors."

Gandhi Sriwidodo. See "— Board of Directors."

Ignatius Tallulembang. See "— Board of Directors."

Heru Setiawan. See "— Board of Directors."

Koeshartanto. See "— Board of Directors."

M. Haryo Yunianto. See "— Board of Directors."

The Audit Committee

The Audit Committee is headed by a member of the Board of Commissioners, who must be an independent commissioner, and must include at least two other persons, who do not have to be members of the Board of Commissioners. The current Head of the Audit Committee is Tanri Abeng. The other members of the Audit Committee are Sahala Lumban Gaol, Agus Yulianto, Bonar Lumban Tobing. The Audit Committee supports the Board of Commissioners as a consulting, controlling and initiating body in the areas of communicating with internal and external auditors, supervising the independence and objectivity of the internal audit function, reviewing and assessing the independence of external auditors, reviewing and assessing financial reporting as well as assessing the adequacy and effectiveness of internal control systems.

The committee normally meets at least 12 times a year for the time necessary to fulfill its purpose, which is estimated to be no less than one hour, or more frequently as circumstances dictate. In 2018, the committee held 53 meetings, lasting approximately two or more hours each.

The Risk Management Monitoring Committee

The Investment and Risk Management Committee is headed by a member of the Board of Commissioners and must include at least two other persons. The current Head of the Risk Management Monitoring Committee is Arcandra Tahar. The other members are Sahala Lumban Gaol, Alexander Lay, Yusuf Didi Sediarto, Poerwo Tjahjono and Averrouz Mostavan. The Risk Management Monitoring Committee proposes risk management guidelines to the Board of Commissioners and advises the Board of Commissioners on these matters.

The committee normally meets at least 12 times a year for the time necessary to fulfill its purpose, which is estimated to be no less than one hour, or more frequently as circumstances dictate. In 2018, the committee held five meetings, lasting approximately two or more hours each.

Compensation

Payment of compensation to the commissioners and directors is determined at the annual shareholder's general meeting. In 2018, total salaries paid to the commissioners and directors as a group was US$47.3 million.

As of December 31, 2018 and March 31, 2019, we had employee benefits obligations of US$2,083.4 million and US$2,135.5 million, respectively, including pension and other post-employment benefits.

RELATIONSHIP WITH THE GOVERNMENT

Overview

We are a profit-based, state-owned limited liability company *(Persero)*, created pursuant to the Oil and Gas Law of 2001 in conjunction with Government Regulation No. 31 of 2003 on the Transfer of Form of *Perusahaan Pertambangan Minyak dan Gas Bumi Negara (Pertamina)* to *Perusahaan Perseroan (Persero)* ("GR 31"). Our formal establishment was through Deed of Establishment No. 20, dated September 17, 2003, drawn up before Lenny Janis Ishak, SH, Notary in Jakarta. Our establishment by the Government was conducted by way of a contribution in kind of all the Government's assets in PERTAMINA, including PERTAMINA's assets in its subsidiaries and joint venture companies at the time of the enactment date of GR 31 but excluding PERTAMINA's assets that had been transferred to BPMIGAS. One of the Government's objectives in establishing us as a limited liability company was to contribute to the public welfare of Indonesia by enhancing domestic economic activity.

History

Prior to our current form, we operated in Indonesia for more than 55 years through our various legal predecessors. We were first established on December 10, 1957, under the name *Perusahaan Minyak Nasional* ("PT PERMINA") pursuant to the Decree of Minister of Industry No. 3177/M and Decree of the Head of Staff of Army as the Central Commandant of War No. PRT/PM/017/1957, both dated October 15, 1957. This created the first national oil company of Indonesia.

In 1961, PT PERMINA was consolidated into a newly established company pursuant to Government Regulation No. 198 Year 1961, dated June 5, 1961, named *PN PERMINA (Perusahaan Negara Pertambangan Minyak Nasional)*. Further, in 1968, the Government established another new entity named *Perusahaan Negara Pertambangan Minyak dan Gas Bumi Nasional* (PN PERTAMINA), pursuant to Government Regulation No. 27 Year 1968, dated August 20, 1968, and consolidated both PN PERMINA as well as *Perusahaan Negara Pertambangan Minyak Indonesia* ("PN PERTAMIN"), which was another oil company established pursuant to Government Regulation No. 3 Year 1961, dated February 13, 1961. With the enactment of Law No. 8 Year 1971 regarding *Perusahaan Pertambangan Minyak dan Gas Bumi* ("Law No. 8/1971"), PN PERTAMINA was dissolved and all of its assets were contributed as the capital of the newly established company named PERTAMINA.

Within that period, the rights to explore and exploit crude oil and natural gas in Indonesia were delegated to us by the Government, as stipulated by Law No. 8/1971. As a representative of the Government, we acted as the sole holder of the mine concession right for all oil and gas areas under the jurisdiction of the Republic of Indonesia. In order to conduct the exploration and exploitation of oil and gas mining, we entered into contracts with third party contractors in the form of PSCs and other production sharing arrangements. Within this period, we also regulated all aspects of the oil and gas industry in Indonesia.

In 2001, the Oil and Gas Law of 2001 was enacted, terminating the exclusive rights held by PERTAMINA. Under the Oil and Gas Law of 2001, BPMIGAS (the predecessor to SKK MIGAS) and BPH MIGAS were established to regulate the upstream and downstream sectors of the Indonesian oil and gas industry. With the dissolution of PERTAMINA and the establishment of our Company in 2003, we became a state-owned limited liability company. Further, as a result, we restructured our business into upstream and downstream sectors operated through separate directorates and subsidiaries. See "Indonesian Regulatory Framework" for more information about the Indonesian oil and gas regulatory framework and "Corporate Structure" for more information on our subsidiaries.

Government as Shareholder

The Government owns 100% of our issued share capital. Our authorized share capital is Rp. 600,000 billion and our initial issued and paid up capital was Rp. 171,227,044 billion as reflected in our articles of association and pursuant to Minister of Finance Decree No. S-217/MBU/04/2018 dated April 11, 2018 which was retrospectively applied to 2003.

As our sole shareholder, the Government is entitled to receive dividend payments from us on an interim or annual basis. In 2016, 2017 and 2018, we declared dividends of Rp. 6.8 trillion (US$499.4 million), Rp. 12.1 trillion (US$907.4 million) and Rp. 8.6 trillion (US$614.9 million), respectively, to the Government. For 2019, the Government is targeting us to pay 30% or less of our projected profits to the Government in dividends. The Government is also entitled, in its capacity as our sole shareholder, to approve any significant acquisitions which we may propose in line with our business strategy. See "Risk Factors — Risks Relating to Our Company — We may not be able to consummate future acquisitions, joint ventures or investments. In addition, any acquisitions, joint ventures or investments which we are able to consummate could adversely affect us."

As we are wholly owned by the Government, our commissioners and directors are appointed by the Government, through the Ministry of State-Owned Enterprises, based on merit.

In 2008, the Government approved our conversion to a non-listed public company, which requires, among other things, the submission of a registration statement to the Indonesian Capital Markets and Financial Institution Supervisory Board and a Government Regulation to enact the change of status. The decision to convert our Company to a non-listed public company is intended to improve our transparency and subject us to higher corporate governance standards.

Government as Regulator

The Government divides the oil and gas industry into upstream and downstream sectors. The upstream sector is controlled by SKK MIGAS (as successor to BPMIGAS), on behalf of the Government, as the holder of the exclusive mine concession rights in Indonesia. The downstream sector is regulated by BPH MIGAS, an independent governmental agency tasked with the supervision and regulation of downstream operations in Indonesia. The objective of BPH MIGAS is to ensure the availability and distribution of refined oil products throughout Indonesia and to promote gas utilization in the domestic market.

The DGOG is the regulator of general policies in relation to the upstream and downstream sectors. The DGOG is authorized to formulate the policies and regulations relating to oil and gas in Indonesia. In order to carry out its duties, the DGOG may, among other things, prepare and implement policies on oil and gas, specify the standards, norms, guidelines, criteria and procedures for the oil and gas industry; and provide technical and evaluation guidance to oil and gas companies.

The policies set forth by SKK MIGAS, BPH MIGAS, and the DGOG impact many of our business activities. Any changes in these policies could have a significant effect on our competitive position, operations and financial condition. See "Risk Factors — Risks Relating to the Oil, Gas and Geothermal Industry — Increased regulation by governments and governmental agencies may increase the cost of regulatory compliance and limit our access to new exploration properties" for information on the risks which we face in connection with such regulation. Also, see "Indonesian Regulatory Framework" for more information on the oil and gas industry in Indonesia.

Certain Government agencies have different supervisory roles in relation to our business activities. The DGOG, SKK MIGAS and BPH MIGAS are our main regulators. The DGOG creates policies and

regulations relating to health, safety and the environment, as well as issuing operating licenses. The Ministry of the Environment monitors the compliance of our business activities with the prevailing environmental laws and regulations. SKK MIGAS and BPH MIGAS regulate our upstream and downstream oil and gas businesses respectively. The Parliament reviews and approves the State Budget, which includes the subsidies to be paid to us pursuant to our PSO mandate. The Ministry of State-Owned Enterprises approves our annual budget, including the amount of our subsidies pursuant to our PSO mandate, at our shareholder's meetings and our long-term investments and funding plans. The Minister of Finance monitors our finances and provides offshore loans, grants and subsidies to us. The Minister of Finance and BAPPENAS approve investment projects which form part of the Government budget. See "— Government as Lender."

The PSO mandate to distribute subsidized fuel in specified regions of Indonesia is granted by the Government on an annual basis. Our PSO mandate was renewed by the Government in 2014 for another year. Under our PSO mandate, we are obliged to distribute kerosene, automotive diesel oil and certain grades of motor gasoline within Indonesia. Pursuant to the PSO mandate, we are entitled to receive payment from the Government as a reimbursement of subsidized fuel price, pursuant to the prevailing laws and regulations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — PSO Mandate" for details of our PSO compensation. The PSO mandate is not assignable. The PSO mandate is not exclusive; if there is scarcity of a PSO product within an area, BPH MIGAS can appoint other business entity to assist us to overcome the shortage.

Since 2007, we were assigned responsibility by the Government to distribute LPG in 3kg cylinders in connection with the kerosene conversion program. Under the terms of this assignment, we are entitled to receive compensation based on a reimbursement of costs and a profit margin from the Government. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Results of Operations — PSO Mandate" for details of our compensation for distribution of LPG on behalf of the Government.

We also consult with the Government on increases in the prices of the LPG in 12kg and 50kg cylinders that we market and distribute in Indonesia.

Our distribution and sale of CNG to public and private transportation vehicles is carried out pursuant to the CNG mandate by the Government. The price at which CNG is purchased and sold is fixed by the Government and we earn a fixed margin from our distribution of CNG. See "Business — Pertamina Gas Business — CNG" for details of our compensation for the distribution and sale of CNG.

The Government supervises the activities in relation to geothermal resources through the Directorate General of New Energy, Renewable Energy and Energy Conservation (a directorate under the Ministry of Energy and Mineral Resources), through the issuance of policies and regulations.

Government as Partner

We, through our direct and indirect subsidiaries, have entered into cooperation contracts with BPMIGAS (such contracts now assumed by SKK MIGAS), as the representative of the Government, to conduct oil and gas upstream activities over a designated block that spans much of Indonesia. The term of a cooperation contract is 30 years from its date. See "Business — Pertamina Upstream Business" for a description of our operations, including those under cooperation contracts.

Under the terms of the cooperation contract, SKK MIGAS is responsible for the supervision of the working area, while we are responsible for the operation of the working area. We contribute funding,

technical skill and expertise, as well as bear the risk of operations in the working area. For cooperation contracts entered into prior to the enactment of the Oil and Gas Law of 2001, approximately 33% of the crude oil and gas produced is allocated to SKK MIGAS and approximately 67% is allocated to us after cost recovery and we are compensated for DMO at the market rate. For cooperation contracts entered into after the enactment of the Oil and Gas Law of 2001, approximately 85% of the crude oil and gas produced is allocated to SKK MIGAS and approximately 15% of is allocated to us after cost recovery and tax and we are compensated for DMO at a reduced price which is less than the market rate and varies between cooperation contracts.

Pursuant to a letter dated February 1, 2005, BPMIGAS appointed us as its selling agent with respect to its crude oil entitlement under cooperation contracts and we are entitled to receive fees as compensation. Under this agreement, we are obligated to sell the entire portion of such crude oil and natural gas entitlement on its behalf and remit the proceeds to BPMIGAS (now SKK MIGAS).

Government as Lender

We have received financing from the Government in the form of a two-step loan from OECF. The Government originally lent to OECF an amount of ¥11,816.0 million (US$104.9 million), pursuant to a loan agreement between the Government and OECF dated November 29, 1994. We, in turn, borrowed ¥1,172.9 million (US$10.4 million) from OECF under a two-step loan agreement dated May 7, 2007 among us as borrower, the Government as co-obligor and OECF as lender. The proceeds of this loan were used to finance the construction of the Airport Fuel Filling Depot of Ngurah Rai International Airport in Bali. The two-step loan matures 30 years from November 29, 1994, the date of the loan agreement between the Government and OECF. There is no collateral given by our Company for the two-step loan, as the Government remains the primary obligor of the loan. The two-step loan bears interest at 3.1% per annum. Any late principal payments will be subject to a 2% per annum penalty.

We have also received financing from the Government in the form of a two-step loan from JICA. The Government obtained a loan of ¥26,966.0 million (US$239.3 million) from JICA under which we were appointed as executing and implementing agency, pursuant to a loan agreement between the Government and JICA dated March 29, 2011. The loan is to be utilized for the implementation of the Lumut Balai geothermal power plant project. There is no collateral given by the Company for this two-step loan, as the Government remains the primary obligor of the loan. The two-step loan is available as two loan facilities, one of which is ¥25,834.0 million (US$229.3 million) and is related to the construction of the project and bears interest at 0.6% per annum and the other facility is ¥1,132.0 million (US$10.0 million) and is related to consultants for the project and bears interest at 0.02% per annum. Any late principal payments will be subject to a 2% per annum penalty.

In addition, we received financing from the Government in the form of a two-step loan from the Japan International Cooperation Agency, together with the IBRD. The Government obtained a loan of US$300.0 million from IBRD under which we were appointed as executing agency, pursuant to two loan agreements, each between the Government and IBRD dated December 5, 2011. One loan amounted to US$175.0 million and the other amounted to US$125.0 million. The loans are to be utilized for the implementation of the Ulubelu and Lahendong geothermal clean energy investment project. There is no collateral given by the Company for this two-step loan, as the Government remains the primary obligor of the loan. Repayment of the principal will be on a semi-annual basis, commencing on October 10, 2020 until October 10, 2035 for the US$175.0 million loan, and commencing on October 10, 2021 until April 10, 2051 for the US$125.0 million loan. The interest rate from the World Bank is LIBOR plus 0.45% + 0.05% (bank charges) plus a variance spread per annum, and the interest rate from the Japan International Cooperation Agency is 0.25% + 0.25% per annum.

We received financing from the Government in the form of a two-step loan from the Japan Bank for International Cooperation ("JBIC"). On May 28, 2003, the Government obtained two loans

consisting of ¥44,702.0 million (US$402.3 million) and ¥4,386.0 million (US$39.5 million), with interest rates of 1.45% and 1.25% per annum respectively. The loans are to be utilized for the implementation of the development of a gas transmission and pipeline from South Sumatra to West Java and a distribution pipeline in West Java.

We received financing from the Government in the form of a second two-step loan from IBRD. On April 3, 2006, the Government obtained a loan of US$80 million to finance a domestic gas market development project. The IBRD's interest rate to the Government is 1.00% per annum.

On September 15, 2000, PGN and the Government entered into a loan agreement, which provides for the Government's relending of EIB loan proceeds not exceeding €70.0 million (US$81.0 million) to PGN as part of the financing of the gas transmission and distribution project phase II. The loans consist of €44.3 million (US$51.3 million) and €10.3 million (US$11.9 million), with interest rates of 4.9% and 5.3% respectively.

Government as Customer

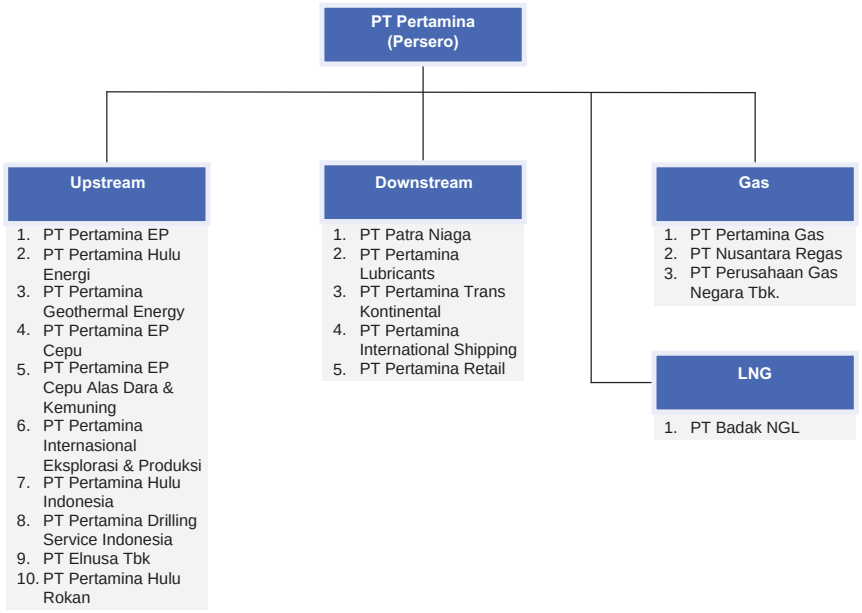
A number of other state-owned companies controlled by the Government (including PLN, PT Timah (Persero) Tbk, and Garuda) purchase fuel from us. Further, we supply our fuel to Government offices, such as the Indonesian police and the Indonesian Armed Forces. Our customers who are state-owned companies and Government offices purchase fuel from us on an arms'-length basis, based on market pricing for such fuel.

As of December 31, 2018, we had trade receivables of US$3,231.1 million, 40.2% of which was owed to us by our related parties. Out of this amount, US$381.6 million was owed to us by PLN, and US$318.1 million is owed to us by the Indonesian Armed Forces and the Ministry of Defense. US$30.7 million of our trade receivables owed to us by our related parties have been outstanding for over two years. As of March 31, 2019, we had trade receivables of US$3,724.2 million, 41.3% of which was owed to us by our related parties. Out of this amount, US$433.8 million was owed to us by the Indonesian Armed Forces, US$386.0 million was owed to us by PT Garuda Indonesia (Persero) Tbk, US$366.9 million was owed to us by PLN, US$43.0 million was owed to us by PT Patra SK, US$23.0 million was owed to us by PT Pupuk Indonesia (Persero), US$12.7 million was owed to us by Polisi Republik Indonesia, US$11.7 million was owed to us by PT Merpati Nusantara Airlines (Persero), US$7.4 million was owed to us by PT Aneka Tambang, US$0.4 million was owed to us by PT Pembangkit Jawa-Bali and US$0.02 million was owed to us by PPT Energy Trading Co., Ltd. As of December 31, 2018 and March 31, 2019, we have made provisions for impairment of US$32.7 million and US$33.2 million, respectively, against trade receivables owed to us by our related parties. See "Risk Factors — Risks Relating to Our Company — We are exposed to credit risk on our trade receivables," "Risk Factors — Risks Relating to Our Downstream Operations — We are dependent on certain key Government-owned customers and the loss of, or a significant reduction in, purchases by such customers could adversely affect our business," and "Management's Discussion And Analysis of Financial Condition and Results of Operations — Market Risks — Counterparty and Concentration of Credit Risks."

CORPORATE STRUCTURE

We have an operating history of more than 60 years and were established on December 10, 1957 under the name PT PERMINA. In 1961, we changed our name to PN PERMINA and, after our merger with PN PERTAMIN in 1968, became PN PERTAMINA. With the enactment of Law 8 of 1971, we became PERTAMINA. This name persisted until we changed our legal status to an Indonesian limited liability company under Deed of Establishment No. 20 dated September 17, 2003 drawn up before Lenny Janis Ishak, SH, Notary in Jakarta, which was approved by the Minister for Law & Human Rights under its Decision No. C-24025 HT.01.01.TH.2003 on October 9, 2003 and we became PT Pertamina (Persero).

The following chart sets forth our key operating companies by business segments. This chart does not show all of our subsidiaries and associates. For a more complete discussion of our direct and indirect subsidiaries and affiliates, please refer to Note 1b of our consolidated financial statements for the years ended December 31, 2018, 2017 and 2016 and the three months ended March 31, 2019 and 2018, included elsewhere in this Offering Memorandum.



Source: Pertamina

We are required under the Oil and Gas Law of 2001 to operate the upstream and downstream sectors of our business through separate legal entities. Following the enactment of the Oil and Gas Law of 2001, we restructured our business and as a result, our upstream assets, operations and joint ventures, our downstream gas business and our supporting business units for our upstream and downstream operations and our non-core businesses are held and operated through subsidiaries of our Company. Our upstream business development unit, the majority of our downstream assets, operations and joint ventures and our LNG business continue to be held and operated through our Company.

The following table sets forth our core subsidiaries and associates and their respective businesses as of March 31, 2019.

Subsidiaries and Associates Business	Place of Incorporation	Interest (%)	Business
PT Pertamina EP	Indonesia	● The Issuer 99.99% ● Pertamina Pedeve Indonesia 0.01%	Management of upstream oil and gas business which includes exploration, exploitation, and sales of oil and gas produced from the exploitation activities.
PT Pertamina Hulu Energi	Indonesia	● The Issuer 98.72% ● Pertamina Pedeve Indonesia 1.28%	Upstream oil and gas and energy business management both of which is conducted inside and outside the country. It also carries out related and/ or supporting business activities in the field of oil and gas.
PT Pertamina EP Cepu[(1)]	Indonesia	● The Issuer 99% ● Pertamina Pedeve Indonesia 1%	Upstream oil and gas business management, including exploration, exploitation and production in the Cepu block.
PT Pertamina EP Cepu ADK . .	Indonesia	● The Issuer 99% ● Pertamina Pedeve Indonesia 1%	Upstream business management, including exploration, exploitation and production in Block Cepu Alas Dara & Kemuning.
PT Pertamina Internasional Eksplorasi dan Produksi	Indonesia	● The Issuer 99.999997% ● Pertamina Pedeve Indonesia 0.000003%	Management of upstream operations in the field of oil, gas and energy which includes exploration and production activities conducted overseas.
PT Pertamina Hulu Rokan	Indonesia	● The Issuer 99.87% ● Pertamina Pedeve Indonesia 0.13%	Upstream business management, including exploration, exploitation and production in the Rokan block.

Subsidiaries and Associates Business	Place of Incorporation	Interest (%)	Business
PT Pertamina Hulu Indonesia	Indonesia	• The Issuer 99.93% • Pertamina Pedeve Indonesia 0.07%	Oil, natural gas and energy business, carrying out exploration and exploitation services as well as direct and indirect energy-related business activities. It has a participating equity interest in domestic operations and carries out services related to oil, natural gas and energy businesses and other business, which is directly or indirectly related to the businesses described above.
PT Pertamina Geothermal Energy	Indonesia	• The Issuer 91.09% • Pertamina Pedeve Indonesia 8.91%	Management and development of geothermal resources, which includes exploration and exploitation activities, the production of steam for electricity generation, consulting services, construction, operation and maintenance as well as technology development.
PT Pertamina Drilling Services Indonesia	Indonesia	• The Issuer 99.89% • Pertamina Pedeve Indonesia 0.11%	Management and development of drilling services, including exploration and exploitation of oil and gas or geothermal resources.
PT Elnusa Tbk.	Indonesia	• The Issuer 41.10% • DP Pertamina 14.90% • Public 44.00%	The management of oil and gas services which include, among others, seismic, drilling and oil field management services.
PT Pertamina Gas	Indonesia	• The Issuer 48.99% • PT Pertamina Dana Ventura 0.01% • PGN 51%	Business management in the fields of commerce, transportation, distribution, processing and other business related to natural gas and its derivatives.
PT Perusahaan Gas Negara Tbk.	Indonesia	• The Issuer 56.964% • Public 43.036% • Republic of Indonesia 0%	Business management in the fields of commerce, transportation, distribution, processing and other business related to natural gas and its derivatives.

Subsidiaries and Associates Business	Place of Incorporation	Interest (%)	Business
PT Pertamina Power Indonesia	Indonesia	• The Issuer 99.999031% • Pertamina Pedeve Indonesia 0.000969%	Electricity generation, production, repair and trade of equipment for electricity generated from other energy sources such as natural gas hydro, geothermal, solar, and other resources.
PT Pertamina Patra Niaga	Indonesia	• The Issuer 99.912% • Pertamina Trans Kontinental 0.088%	Technology services, trade services for non-fuel and oil and gas mining industry.
PT Pertamina Retail	Indonesia	• The Issuer 99.9994% • Pertamina Pedeve Indonesia 0.0006%	Retail gas station business management as well as trade and transportation services for certain fuel products.
PT Pertamina Lubricants	Indonesia	• The Issuer 99.95% • Pertamina Pedeve Indonesia 0.05%	Management of production, trading, transportation, distribution, storage activities for lubricant and its derivatives.
PT Pertamina Trans Kontinental	Indonesia	• The Issuer 99.999% • Pertamina Pedeve Indonesia 0.001%	Shipping operation services including supply vessels, tug boats, cargo vessels and agency.
PT Pertamina International Shipping	Indonesia	• The Issuer 99.95% • Pertamina Pedeve Indonesia 0.05%	Business management in the field of shipping, with main business activity being the shipping of oil and gas commodities, and other supporting activities.
PT Kilang Pertamina Internasional	Indonesia	• The Issuer 99.90% • Pertamina Pedeve Indonesia 0.10%	Management of refinery in oil, natural gas and new and renewable energy, domestic and overseas, comprising activities in production, refinery and trading.

Subsidiaries and Associates Business	Place of Incorporation	Interest (%)	Business
PT Nusantara Regas	Indonesia	● The Issuer 82.78 (60% directly and the remainder through PGN's 40% stake)	Operation and development of floating storage facilities and regasification terminals ("FSRT"), including, purchase of LNG and marketing of FSRT facilities products and other related business activities to optimizing PT Nusantara Regas' value to its shareholders

Note:

(1) Under the Oil and Gas Law of 2001 and Upstream Regulation, our interests in any new oil and gas work areas are required to be held through separate legal entities and we established this subsidiary to hold our interest in the Cepu block which was acquired after the Oil and Gas Law of 2001 and Upstream Regulation came into force. We intend to establish new subsidiaries to hold interests in any new oil and gas work areas we acquire in the future.

We have certain other non-key subsidiaries and joint ventures through which we hold assets and participate in other non-core businesses. See "Business — Other Businesses."

DESCRIPTION OF THE NOTES

1. General

(a) The particular terms of any Notes sold will be described in an accompanying supplement to this Offering Memorandum (a "**Pricing Supplement**"). The terms and conditions set forth in this "Description of the Notes" will apply to each Note unless otherwise specified in the applicable Pricing Supplement and in such Note.

(b) The Notes will be duly authorized issues of Notes of PT Pertamina (Persero) (the "**Company**") (each Note a "**Note,**" and collectively, the "**Notes**"), and will be issued pursuant to an Indenture dated as of May 3, 2013, between the Company and The Bank of New York Mellon, as Trustee (the "**Trustee**"), as amended, supplemented and/or restated from time to time (the "**Indenture**"). The terms of the Notes will be subject to all the provisions contained in the Indenture and the conditions set out in the Notes (as modified and supplemented by the applicable Pricing Supplement, the "**Conditions**"). The Pricing Supplement for each Note will supplement the Conditions and may specify other terms and conditions, which shall, to the extent so specified or to the extent inconsistent with the Conditions, replace or modify the Conditions for the purposes of the Note. The holders of the Notes (the "**Holders**") will be entitled to the benefits of, be bound by, and be deemed to have notice of, all of the provisions of the Indenture. A copy of the Indenture is on file and may be inspected at the Corporate Trust Office of the Trustee in New York City. All capitalized terms used in this "Description of the Notes" but not defined herein shall have the meanings assigned to them in the Indenture and in the Pricing Supplement.

(c) The Notes will (i) be direct, unsecured and unsubordinated obligations of the Company; (ii) be senior in right of payment to any existing and future obligations of the Company expressly subordinated in right of payment to the Notes; (iii) rank at least pari passu in right of payment with all other unsecured and unsubordinated Debt of the Company (subject to any priority rights of such unsubordinated Debt pursuant to applicable law); and (iv) be effectively subordinated to its secured obligations and the obligations of its Subsidiaries.

(d) Registered Notes will be issued in fully registered form, without coupons. Registered Notes may be issued in certificated form (the "**Certificated Securities**"), or may be represented by one or more registered global securities (each, a "**Registered Global Security**") held by or on behalf of the Depositary. Certificated Securities will be available only in the limited circumstances set forth in the Indenture. The Registered Notes, and transfers thereof, will be registered as provided in Clause 2.6 of the Indenture. Any person in whose name a Registered Note is registered may (to the fullest extent permitted by applicable law) be treated at all times, by all persons and for all purposes as the absolute owner of such Registered Note regardless of any notice of ownership, theft, loss or any writing thereon.

(e) Bearer Notes will be issued in bearer form, with Coupons (and, where appropriate, Talons) attached, except in the case of Zero Coupon Notes in which case references to interest (other than in relation to interest due after the Maturity Date), Coupons and Talons in the Conditions are not applicable. Installment Notes will be issued with one or more Receipts attached. Bearer Notes may be issued in definitive form, or may be represented by one or more global securities, which may be Temporary Global Notes held by or on behalf of the Depositary. Interests in Temporary Global Notes will be exchangeable for interests in a Permanent Global Note or Definitive Bearer Notes on or

after the Exchange Date (as defined below) upon certification as provided therein. Definitive Bearer Notes will be available only in the limited circumstances set forth in the Indenture. Any holder of any Bearer Note, Receipt, Coupon or Talon may (to the fullest extent permitted by applicable law) be treated at all times, by all persons and for all purposes as the absolute owner of such Bearer Note, Receipt, Coupon or Talon regardless of any notice of ownership, theft, loss or any writing thereon. Title to the Bearer Notes and any Coupon will pass by delivery.

2. Principal and Interest

The Company, for value received, will promise to pay to the Holder of a Note on the Maturity Date (or on such earlier date as the amount payable upon redemption under the Conditions may become repayable in accordance with the Conditions) the amount payable upon redemption to the Holder under the Conditions and (unless the Note does not bear interest under the Conditions) to pay to the Holder interest in respect of such Note from the Interest Commencement Date in arrears at the rates, in the amounts and on the dates for payment provided for in the Conditions together with such other sums and additional amounts (if any) as may be payable under the Conditions, in accordance with the Conditions.

2A. General

A Note may be a Fixed Rate Note, a Floating Rate Note, a Zero Coupon Note, an Index Linked Interest Note, an Index Linked Redemption Note, an Installment Note, a Dual Currency Note or a Partly Paid Note, a combination of any of the foregoing or any other kind of Note, depending upon the Interest and Redemption/Payment Basis shown in the Pricing Supplement. Details of such Interest, Redemption and/or Payment Basis not set out in this "Description of the Notes" will be set out in the Pricing Supplement.

2B. Interest and Calculations

(a) **Interest on Fixed Rate Notes**: Each Fixed Rate Note will bear interest on its outstanding nominal amount from the Interest Commencement Date at the rate per annum (expressed as a percentage) equal to the Rate of Interest, such interest being payable in arrears on each Interest Payment Date. The amount of interest payable shall be determined in accordance with Condition 2B(h).

(b) **Interest on Floating Rate Notes and Index Linked Interest Notes**:

(i) *Interest Payment Dates*: Each Floating Rate Note and Index Linked Interest Note will bear interest on its outstanding nominal amount from the Interest Commencement Date at the rate per annum (expressed as a percentage) equal to the Rate of Interest, such interest being payable in arrears on each Interest Payment Date. The amount of interest payable shall be determined in accordance with Condition 2B(h). Such Interest Payment Date(s) is either shown in the Pricing Supplement as Specified Interest Payment Dates or, if no Specified Interest Payment Date(s) is shown in the Pricing Supplement, Interest Payment Date shall mean each date which falls the number of months or other period shown in the Pricing Supplement as the Interest Period after the preceding Interest Payment Date or, in the case of the first Interest Payment Date, after the Interest Commencement Date.

(ii) *Business Day Convention*: If any date referred to in the Conditions that is specified to be subject to adjustment in accordance with a Business Day Convention would

otherwise fall on a day that is not a Business Day, then, if the Business Day Convention specified is (A) the Floating Rate Business Day Convention, such date shall be postponed to the next day that is a Business Day unless it would thereby fall into the next calendar month, in which event (x) such date shall be brought forward to the immediately preceding Business Day and (y) each subsequent such date shall be the last Business Day of the month in which such date would have fallen had it not been subject to adjustment, (B) the Following Business Day Convention, such date shall be postponed to the next day that is a Business Day, (C) the Modified Following Business Day Convention, such date shall be postponed to the next day that is a Business Day unless it would thereby fall into the next calendar month, in which event such date shall be brought forward to the immediately preceding Business Day or (D) the Preceding Business Day Convention, such date shall be brought forward to the immediately preceding Business Day.

(iii) *Rate of Interest for Floating Rate Notes*: The Rate of Interest in respect of Floating Rate Notes for each Interest Accrual Period shall be determined in the manner specified in the Pricing Supplement and the provisions below relating to either ISDA Determination or Screen Rate Determination shall apply, depending upon which is specified in the Pricing Supplement.

(A) ISDA Determination for Floating Rate Notes

Where ISDA Determination is specified in the Pricing Supplement as the manner in which the Rate of Interest is to be determined, the Rate of Interest for each Interest Accrual Period shall be determined by the Calculation Agent as a rate equal to the relevant ISDA Rate. For the purposes of Condition 2B(b)(iii)(A), "**ISDA Rate**" for an Interest Accrual Period means a rate equal to the Floating Rate that would be determined by the Calculation Agent under a Swap Transaction under the terms of an agreement incorporating the ISDA Definitions and under which:

(x) the Floating Rate Option is as specified in the Pricing Supplement;

(y) the Designated Maturity is a period specified in the Pricing Supplement; and

(z) the relevant Reset Date is the first day of that Interest Accrual Period unless otherwise specified in the Pricing Supplement.

For the purposes of Condition 2B(b)(iii)(A), "**Floating Rate,**" "**Calculation Agent,**" "**Floating Rate Option,**" "**Designated Maturity,**" "**Reset Date**" and "**Swap Transaction**" have the meanings given to those terms in the ISDA Definitions.

(B) Screen Rate Determination for Floating Rate Notes

(x) Where Screen Rate Determination is specified in the Pricing Supplement as the manner in which the Rate of Interest is to be determined, the Rate of Interest for each Interest Accrual Period will, subject as provided below, be either:

(1) the offered quotation; or

(2) the arithmetic mean of the offered quotations,

(expressed as a percentage rate per annum) for the Reference Rate which appears or appear, as the case may be, on the Relevant Screen Page as at either 11.00 a.m. (London time in the case of LIBOR or Brussels time in the case of EURIBOR) on the Interest Determination Date in question as determined by the Calculation Agent. If five or more of such offered quotations are available on the Relevant Screen Page, the highest (or, if there is more than one such highest quotation, one only of such quotations) and the lowest (or, if there is more than one such lowest quotation, one only of such quotations) shall be disregarded by the Calculation Agent for the purpose of determining the arithmetic mean of such offered quotations.

If the Reference Rate from time to time in respect of Floating Rate Notes is specified in the Pricing Supplement as being other than LIBOR or EURIBOR, the Rate of Interest in respect of such Notes will be determined as provided in the Pricing Supplement.

(y) if the Relevant Screen Page is not available or if, Condition 2B(b)(iii)(B)(x)(1) applies and no such offered quotation appears on the Relevant Screen Page or if Condition 2B(b)(iii)(B)(x)(2) above applies and fewer than three such offered quotations appear on the Relevant Screen Page in each case as at the time specified above, subject as provided below, the Calculation Agent shall request, if the Reference Rate is LIBOR, the principal London office of each of the Reference Banks or, if the Reference Rate is EURIBOR, the principal Euro-zone office of each of the Reference Banks, to provide the Calculation Agent with its offered quotation (expressed as a percentage rate per annum) for the Reference Rate if the Reference Rate is LIBOR, at approximately 11.00 a.m. (London time), or if the Reference Rate is EURIBOR, at approximately 11.00 a.m. (Brussels time) on the Interest Determination Date in question. If two or more of the Reference Banks provide the Calculation Agent with such offered quotations, the Rate of Interest for such Interest Accrual Period shall be the arithmetic mean of such offered quotations as determined by the Calculation Agent; and

(z) if Condition 2B(b)(iii)(B)(y) above applies and the Calculation Agent determines that fewer than two Reference Banks are providing offered quotations, subject as provided below, the Rate of Interest shall be the arithmetic mean of the rates per annum (expressed as a percentage) as communicated to (and at the request of) the Calculation Agent by the Reference Banks or any two or more of them, at which such banks were offered, if the Reference Rate is LIBOR, at approximately 11.00 a.m. (London time) or, if the Reference Rate is EURIBOR, at approximately 11.00 a.m. (Brussels time) on the relevant Interest Determination Date, deposits in the Specified Currency for a period equal to that which would have been used for the Reference Rate by leading banks in, if the Reference Rate is LIBOR, the London inter-bank market or, if the Reference Rate is EURIBOR, the Euro-zone inter bank market, as the case may be, or, if fewer than two of the Reference Banks provide the Calculation Agent with such offered rates, the offered rate for deposits in the Specified Currency for a period equal to that which would have been used for the Reference Rate, or the arithmetic mean of the offered rates for deposits in the Specified Currency for a period equal to that which would have been used for the Reference Rate, at which, if the Reference Rate is LIBOR, at approximately 11.00 a.m. (London time) or, if the Reference Rate is

EURIBOR, at approximately 11.00 a.m. (Brussels time), on the relevant Interest Determination Date, any one or more banks (which bank or banks is or are in the opinion of the Trustee and the Company suitable for such purpose) informs the Calculation Agent it is quoting to leading banks in, if the Reference Rate is LIBOR, the London inter-bank market as at 11.00 a.m. (London time) or, if the Reference Rate is EURIBOR, the Euro-zone inter bank market as at 11.00 a.m. (Brussels time), as the case may be, provided that, if the Rate of Interest cannot be determined in accordance with the foregoing provisions of this Condition 2B(b)(iii)(B)(z), the Rate of Interest shall be determined as at the last preceding Interest Determination Date (though substituting, where a different Margin or Maximum or Minimum Rate of Interest is to be applied to the relevant Interest Accrual Period from that which applied to the last preceding Interest Accrual Period, the Margin or Maximum or Minimum Rate of Interest relating to the relevant Interest Accrual Period, in place of the Margin or Maximum or Minimum Rate of Interest relating to that last preceding Interest Accrual Period).

(iv) *Rate of Interest for Index Linked Interest Notes*: The Rate of Interest in respect of Index Linked Interest Notes for each Interest Accrual Period shall be determined in the manner specified in the Pricing Supplement and interest will accrue by reference to an Index or Formula as specified in the Pricing Supplement.

(c) **Zero Coupon Notes**: Where a Note, the Interest Basis of which is specified to be Zero Coupon, is repayable prior to the Maturity Date and is not paid when due, the amount due and payable prior to the Maturity Date shall be the Early Redemption Amount of such Note. As from the Maturity Date, the Rate of Interest for any overdue principal of such a Note shall be a rate per annum (expressed as a percentage) equal to the Amortization Yield (as described in Condition 8(b)(i)).

(d) **Dual Currency Notes**: In the case of Dual Currency Notes, if the rate or amount of interest is to be determined by reference to a Rate of Exchange or a method of calculating Rate of Exchange, the rate or amount of interest payable shall be determined in the manner specified in the Pricing Supplement.

(e) **Partly Paid Notes**: In the case of Partly Paid Notes (other than Partly Paid Notes which are Zero Coupon Notes), interest will accrue as aforesaid on the paid-up nominal amount of such Notes and otherwise as specified in the Pricing Supplement.

(f) **Accrual of Interest**: Interest shall cease to accrue on each Note on the due date for redemption unless, upon due presentation, payment is improperly withheld or refused, in which event interest shall continue to accrue (both before and after judgment) at the Rate of Interest in the manner provided in this Condition 2B to the Relevant Date.

(g) Margin, Maximum/Minimum Rates of Interest, Installment Amounts and Redemption Amounts and Rounding:

(i) If any Margin is specified in the Pricing Supplement (either (x) generally, or (y) in relation to one or more Interest Accrual Periods), an adjustment shall be made to all Rates of Interest, in the case of (x), or the Rates of Interest for the specified Interest Accrual Periods, in the case of (y), calculated in accordance with Condition 2B(b) above by adding (if a positive number) or subtracting the absolute value (if a negative number) of such Margin, subject always to Condition 2B(g)(ii).

(ii) If any Maximum or Minimum Rate of Interest, Installment Amount or Redemption Amount is specified in the Pricing Supplement, then any Rate of Interest, Installment Amount or Redemption Amount shall be subject to such maximum or minimum, as the case may be.

(iii) For the purposes of any calculations required pursuant to the Conditions (unless otherwise specified), (x) all percentages resulting from such calculations shall be rounded, if necessary, to the nearest one hundred thousandth of a percentage point (with halves being rounded up), (y) all figures shall be rounded to seven significant figures (with halves being rounded up) and (z) all currency amounts that fall due and payable shall be rounded to the nearest unit of such currency (with halves being rounded up), save in the case of yen, which shall be rounded down to the nearest yen. For these purposes "**unit**" means the lowest amount of such currency that is available as legal tender in the country or countries of such currency.

(h) **Calculations**: The amount of interest payable per Calculation Amount in respect of any Note for any Interest Accrual Period shall be equal to the product of the Rate of Interest, the Calculation Amount specified in the Pricing Supplement, and the Day Count Fraction for such Interest Accrual Period, unless an Interest Amount (or a formula for its calculation) is applicable to such Interest Accrual Period, in which case the amount of interest payable per Calculation Amount in respect of such Note for such Interest Accrual Period shall equal such Interest Amount (or be calculated in accordance with such formula). Where any Interest Period comprises two or more Interest Accrual Periods, the amount of interest payable per Calculation Amount in respect of such Interest Period shall be the sum of the Interest Amounts payable in respect of each of those Interest Accrual Periods. In respect of any other period for which interest is required to be calculated, the provisions above shall apply save that the Day Count Fraction shall be for the period for which interest is required to be calculated.

(i) Determination and Publication of Rates of Interest, Interest Amounts, Final Redemption Amounts, Early Redemption Amounts, Optional Redemption Amounts and Installment Amounts: The Calculation Agent shall, as soon as practicable on each Interest Determination Date, or such other time on such date as the Calculation Agent may be required to calculate any rate or amount, obtain any quotation or make any determination or calculation, determine such rate and calculate the Interest Amounts for the relevant Interest Accrual Period, calculate the Final Redemption Amount, Early Redemption Amount, Optional Redemption Amount or Installment Amount, obtain such quotation or make such determination or calculation, as the case may be, and cause the Rate of Interest and the Interest Amounts for each Interest Accrual Period and the relevant Interest Payment Date and, if required to be calculated, the Final Redemption Amount, Early Redemption Amount, Optional Redemption Amount or any Installment Amount to be notified to the Trustee, the Company, each of the Paying Agents, the Holders, any other Calculation Agent appointed in respect of the Notes that is to make a further calculation upon receipt of such information and, if the Notes are listed on a stock exchange and the rules of such exchange or other relevant authority so require, such exchange or other relevant authority as soon as possible after their determination but in no event later than (i) the commencement of the relevant Interest Period, if determined prior to such time, in the case of notification to such exchange of a Rate of Interest and Interest Amount, or (ii) in all other cases, the fourth Business Day after such determination. Where any Interest Payment Date or Interest Period Date is subject to adjustment pursuant to Condition 2B(b)(ii), the Interest Amounts and the Interest Payment Date so published may subsequently be amended without notice in the event of an extension or shortening of the Interest Period. If the Notes become due and payable under Condition 7, the accrued interest and the Rate of Interest payable in respect of the Notes shall nevertheless continue to be calculated and notified as previously in accordance with

this Condition 2B(i). The determination of any rate or amount, the obtaining of each quotation and the making of each determination or calculation by the Calculation Agent(s) shall (in the absence of manifest error) be final and binding upon all parties.

(j) **Determination or Calculation by Trustee**: If the Calculation Agent does not at any time for any reason determine or calculate the Rate of Interest for an Interest Accrual Period or any Interest Amount, Installment Amount, Final Redemption Amount, Early Redemption Amount or Optional Redemption Amount, the Trustee shall do so (or shall appoint an agent on its behalf to do so) at the expense of the Issuer and such determination or calculation shall be deemed to have been made by the Calculation Agent. In doing so, the Trustee shall apply the foregoing provisions of this Condition 2B, with any necessary consequential amendments, to the extent that, in its opinion, it can do so, and, in all other respects it shall do so in such manner as it shall deem fair and reasonable in all the circumstances. If the Trustee appoints an agent to make such determination or calculation, the Trustee shall not be liable to monitor or supervise any such agent and shall not be liable for any determination or calculation made by any such agent.

(k) **Definitions**: For the purposes of this "Description of the Notes," unless the context otherwise requires, the following defined terms shall have the meanings set out below:

"**Business Day**" means:

(i) in the case of a currency other than euro, a day (other than a Saturday or Sunday) on which commercial banks and foreign exchange markets settle payments in the principal financial center for such currency; and/or

(ii) in the case of euro, a day on which the TARGET System is operating (a "**TARGET Business Day**"); and/or

(iii) in the case of a currency and/or one or more Business Centers, a day (other than a Saturday or a Sunday) on which commercial banks and foreign exchange markets settle payments in such currency in the Business Center(s) or, if no currency is indicated, generally in each of the Business Centers.

"**Day Count Fraction**" means, in respect of the calculation of an amount of interest on any Note for any period of time (from and including the first day of such period to but excluding the last) (whether or not constituting an Interest Period or an Interest Accrual Period, the "**Calculation Period**"):

(i) if "**Actual/Actual**" or "**Actual/Actual — ISDA**" is specified in the Pricing Supplement, the actual number of days in the Calculation Period divided by 365 (or, if any portion of that Calculation Period falls in a leap year, the sum of (A) the actual number of days in that portion of the Calculation Period falling in a leap year divided by 366 and (B) the actual number of days in that portion of the Calculation Period falling in a non leap year divided by 365)

(ii) if "**Actual/365 (Fixed)**" is specified in the Pricing Supplement, the actual number of days in the Calculation Period divided by 365

(iii) if "**Actual/360**" is specified in the Pricing Supplement, the actual number of days in the Calculation Period divided by 360

(iv) if "**30/360,**" "**360/360**" or "Bond Basis" is specified in the Pricing Supplement, the number of days in the Calculation Period divided by 360, calculated on a formula basis as follows:

$$\text{Day Count Fraction} = \frac{[360 \times (Y_2 - Y_1)] + [30 \times M_2 - M_1)] + (D_2 - D_1)}{360}$$

where:

"Y1" = is the year, expressed as a number, in which the first day of the Calculation Period falls;

"Y2" = is the year, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"M1" = is the calendar month, expressed as a number, in which the first day of the Calculation Period falls;

"M2" = is the calendar month, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"D1" = is the first calendar day, expressed as a number, of the Calculation Period, unless such number would be 31, in which case D1 will be 30; and

"D2" = is the calendar day, expressed as a number, immediately following the last day included in the Calculation Period, unless such number would be 31 and D1 is greater than 29, in which case D2 will be 30.

(v) if "**30E/360**" or "Eurobond Basis" is specified in the Pricing Supplement, the number of days in the Calculation Period divided by 360, calculated on a formula basis as follows:

$$\text{Day Count Fraction} = \frac{[360 \times (Y_2 - Y_1)] + [30 \times M_2 - M_1)] + (D_2 - D_1)}{360}$$

where:

"Y1" = is the year, expressed as a number, in which the first day of the Calculation Period falls;

"Y2" = is the year, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"M1" = is the calendar month, expressed as a number, in which the first day of the Calculation Period falls;

"M2" = is the calendar month, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"D1" = is the first calendar day, expressed as a number, of the Calculation Period, unless such number would be 31, in which case D1 will be 30; and

"D2" = is the calendar day, expressed as a number, immediately following the last day included in the Calculation Period, unless such number would be 31 and D1 is greater than 29, in which case D2 will be 30.

(vi) if "**30E/360 (ISDA)**" is specified in the Pricing Supplement, the number of days in the Calculation Period divided by 360, calculated on a formula basis as follows:

$$\text{Day Count Fraction} = \frac{[360 \times (Y_2 - Y_1)] + [30 \times M_2 - M_1)] + (D_2 - D_1)}{360}$$

where:

"Y1" = is the year, expressed as a number, in which the first day of the Calculation Period falls;

"Y2" = is the year, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"M1" = is the calendar month, expressed as a number, in which the first day of the Calculation Period falls;

"M2" = is the calendar month, expressed as a number, in which the day immediately following the last day included in the Calculation Period falls;

"D1" = is the first calendar day, expressed as a number, of the Calculation Period, unless such number would be 31, in which case D1 will be 30; and

"D2" = is the calendar day, expressed as a number, immediately following the last day included in the Calculation Period, unless such number would be 31 and D1 is greater than 29, in which case D2 will be 30.

(vii) if "**Actual/Actual-ICMA**" is specified in the Pricing Supplement,

(a) if the Calculation Period is equal to or shorter than the Determination Period during which it falls, the number of days in the Calculation Period divided by the product of (x) the number of days in such Determination Period and (y) the number of Determination Periods normally ending in any year; and

(b) if the Calculation Period is longer than one Determination Period, the sum of:

(x) the number of days in such Calculation Period falling in the Determination Period in which it begins divided by the product of (1) the number of days in such Determination Period and (2) the number of Determination Periods normally ending in any year; and

(y) the number of days in such Calculation Period falling in the next Determination Period divided by the product of (1) the number of days in such Determination Period and (2) the number of Determination Periods normally ending in any year

where:

"**Determination Period**" means the period from and including a Determination Date in any year to but excluding the next Determination Date and

"**Determination Date**" means the date(s) specified as such in the Pricing Supplement or, if none is so specified, the Interest Payment Date(s).

"**Euro-zone**" means the region comprised of member states of the European Union that adopt the single currency in accordance with the Treaty establishing the European Community, as amended.

"**Interest Accrual Period**" means the period beginning on (and including) the Interest Commencement Date and ending on (but excluding) the first Interest Period Date and each successive period beginning on (and including) an Interest Period Date and ending on (but excluding) the next succeeding Interest Period Date.

"**Interest Amount**" means:

(i) in respect of an Interest Accrual Period, the amount of interest payable per Calculation Amount for that Interest Accrual Period and which, in the case of Fixed Rate Notes, and unless otherwise specified in the Pricing Supplement, shall mean the Fixed Coupon Amount or Broken Amount specified in the Pricing Supplement as being payable on the Interest Payment Date ending the Interest Period of which such Interest Accrual Period forms part; and

(ii) in respect of any other period, the amount of interest payable per Calculation Amount for that period.

"**Interest Commencement Date**" means the Issue Date or such other date as may be specified in, or determined in accordance with the provisions of, the Pricing Supplement.

"**Interest Determination Date**" means, with respect to a Rate of Interest and Interest Accrual Period, the date specified as such in the Pricing Supplement or, if none is so specified, (i) the first day of such Interest Accrual Period if the Specified Currency is Sterling or (ii) the day falling two Business Days in London for the Specified Currency prior to the first day of such Interest Accrual Period if the Specified Currency is neither Sterling nor euro or (iii) the day falling two TARGET Business Days prior to the first day of such Interest Accrual Period if the Specified Currency is euro.

"**Interest Payment Date**" means the date or dates specified as such in, or determined in accordance with the provisions of, the Pricing Supplement.

"**Interest Period**" means the period beginning on (and including) the Interest Commencement Date and ending on (but excluding) the first Interest Payment Date and each successive period beginning on (and including) an Interest Payment Date and ending on (but excluding) the next succeeding Interest Payment Date.

"**Interest Period Date**" means each Interest Payment Date unless otherwise specified in the Pricing Supplement.

"**ISDA Definitions**" means the 2006 ISDA Definitions, as published by the International Swaps and Derivatives Association, Inc., unless otherwise specified in the Pricing Supplement.

"**Rate of Interest**" means the rate or rates of interest payable from time to time in respect of the Note specified in the Pricing Supplement or calculated or determined in accordance with the Conditions and/or the provisions of the Pricing Supplement.

"**Redemption Amount**" means the Final Redemption Amount, Early Redemption Amount or Optional Redemption Amount, as the case may be, each as specified as such in, or determined in accordance with the provisions of, the Pricing Supplement.

"**Redemption Date**" means the Optional Redemption Date specified in the applicable Pricing Supplement or such other date set for redemption of the Notes pursuant to Condition 8.

"**Reference Banks**" means, in the case of a determination of LIBOR, the principal London office of four major banks in the London inter-bank market and, in the case of a determination of EURIBOR, the principal Euro-zone office of four major banks in the Euro-zone inter-bank market, in each case selected by the Calculation Agent or as specified in the Pricing Supplement.

"**Reference Rate**" means the rate specified as such in the Pricing Supplement.

"**Relevant Screen Page**" means such page, section, caption, column or other part of a particular information service as may be specified in the Pricing Supplement.

"**Specified Currency**" means the currency specified as such in the Pricing Supplement or, if none is specified, the currency in which the Notes are denominated.

"**TARGET System**" means the Trans-European Automated Real-Time Gross Settlement Express Transfer (known as TARGET2) System which was launched on November 19, 2007 or any successor thereto.

(l) **Calculation Agent**: The Company shall procure that there shall at all times be one or more Calculation Agents if provision is made for them in the Pricing Supplement and for so long as any Note is Outstanding (as defined in the Indenture). Where more than one Calculation Agent is appointed in respect of the Notes, references in the Conditions to the Calculation Agent shall be construed as each Calculation Agent performing its respective duties under the Conditions. If the Calculation Agent is unable or unwilling to act as such or if the Calculation Agent fails duly to establish the Rate of Interest for an Interest Accrual Period or to calculate any Interest Amount, Installment Amount, Final Redemption Amount, Early Redemption Amount or Optional Redemption Amount, as the case may be, or to comply with any other requirement, the Company shall appoint a leading bank or financial institution engaged in the interbank market (or, if appropriate, money, swap or over-the-counter index options market) that is most closely connected with the calculation or determination to be made by the Calculation Agent (acting through its principal London office or any other office actively involved in such market) to act as such in its place. The Calculation Agent may at any time resign with respect to the Notes of one or more Series by giving not less than 60 days' written notice of resignation to the Company, upon which the Company shall appoint a successor as aforesaid.

2C. Redenomination, Renominalization and Reconventioning

Where Redenomination, Renominalization and Reconventioning is specified in the Pricing Supplement as being Applicable in relation to Notes denominated in the currency of a member state which becomes or announces its intention to become a Participating Member State:

(i) the Company may, without the consent of the Holders of the Notes, on giving not less than 30 days' prior notice ("**Redenomination Notice**") to the Holders of the Notes in accordance with Condition 13, the Trustee and the Paying Agents, with effect from (and including) the Redenomination Date, elect that the aggregate principal amount of each Holder's holding of Notes shall be redenominated into Euro with an aggregate principal amount equal to their

aggregate principal amount in the Relevant Currency and the amount of such payment shall be rounded to the nearest Euro 0.01. The rate for the conversion of the Relevant Currency (as defined below) into Euro shall be the rate established by the Council of the European Union pursuant to Article 881(4) of the Treaty establishing the European Community (the "**Treaty**") (including compliance with rules relating to roundings in accordance with applicable European Community regulations).

"**Participating Member State**" means a Member State of the European Communities which adopts the Euro as its lawful currency in accordance with the Treaty.

"**Redenomination Date**" means any Interest Payment Date falling on or after the date on which the country of the Relevant Currency becomes a Participating Member State, which is specified in the Redenomination Notice.

"**Relevant Currency**" means the currency of denomination of the Notes shown on such Notes and which is specified in the Pricing Supplement.

On or after the Redenomination Date, notwithstanding the other provisions of the Conditions, all payments in respect of the Notes will be made solely in Euro, including payments of interest in respect of a period before the Redenomination Date. Payments will be made in Euro by credit or transfer to a Euro account (or any other account to which Euro may be credited or transferred) specified by the payee. The Company shall appoint an exchange agent if necessary to comply with the procedures and requirements of the relevant clearing system and to give effect to this Condition 2C. None of the Company, the Trustee or any Paying Agent shall be liable to any Holder of Notes or other person for any commissions, costs, losses or expenses in relation to or resulting from the credit or transfer of Euro or any currency conversion or rounding effected in connection therewith;

(ii) provided that the Notes are represented by a Registered Global Security, the Company may, without the consent of the Holders of the Notes, on giving at least 30 days' prior notice to the Holders of the Notes in accordance with Condition 13, the Trustee and the Paying Agents, with effect from the Redenomination Date or such later date as it may specify in that notice, procure that the denomination of the Notes shall be Euro 0.01 and integral multiples thereof;

(iii) the Company may, without the consent of the Holders of the Notes, on giving at least 30 days' prior notice to the Holders of the Notes in accordance with Condition 13, the Trustee and the Paying Agents, with effect from the Redenomination Date or such later Interest Payment Date as it may specify in that notice, elect to amend the conventions which apply in respect of the Notes.

In particular, the Company may procure that the definition of "Business Day" and "Financial Center" in Condition 2B shall be amended so as to be a day on which TARGET is operating, and that, if interest is required to be calculated for a period of less than one year, it will be calculated on the basis of the actual number of days elapsed divided by 365 (or, if any of the days elapsed fall in a leap year, the sum of (A) the number of those days falling in a leap year divided by 366 and (B) the number of those days falling in a non-leap year divided by 365) or on any other basis which is customary and which the Company deems appropriate.

3. Payments

(a) Registered Notes: Principal of (and premium, if any, on) the Notes will be payable against surrender of such Notes at the Corporate Trust Office of the Trustee or, subject to applicable laws and regulations, at the specified office of the applicable Paying Agent in the Place of Payment, by check in the Specified Currency drawn on, or by transfer to an account in the Specified Currency maintained by the Holder with, a bank located in New York City (or, the Financial Center set out in the Pricing Supplement). Unless specified in the Pricing Supplement, payment of interest (including Additional Amounts (as defined below)) on Registered Notes will be made to the persons in whose name such Registered Notes are registered at the end of the Business Day (as defined below) preceding the date on which interest is to be paid (each, a "**Record Date**"), notwithstanding the cancellation of such Registered Notes upon any transfer or exchange thereof subsequent to the Record Date and prior to such Interest Payment Date; provided that if and to the extent the Company shall default in the payment of the interest due on such Interest Payment Date, such defaulted interest shall be paid to the persons in whose names such Registered Notes are registered as of a subsequent record date established by the Company by notice, as provided in Condition 13, by or on behalf of the Company to the Holders not less than 15 days preceding such subsequent record date, such record date to be not less than 10 days preceding the date of payment of such defaulted interest. Payment of interest on Certificated Securities will be made (i) by a check in the Specified Currency drawn on a bank in New York City (or, the Financial Center set out in the Pricing Supplement) mailed to the Holder at such Holder's registered address or (ii) upon application by the Holder of at least the amount specified in the Pricing Supplement in principal amount of Certificated Securities to the Trustee not later than the relevant Record Date, by wire transfer in immediately available funds to an account maintained by the Holder with a bank in New York City (or, the Financial Center set out in the Pricing Supplement), Payment of interest on a Registered Global Security will be made (i) by a check in the Specified Currency drawn on a bank in New York City delivered to the Depositary at its registered address or (ii) by wire transfer in immediately available funds to an in the Specified Currency account maintained by the Depositary with a bank in New York City (or, the Financial Center set out in the Pricing Supplement).

(b) **Bearer Notes**: Each Paying Agent acting through its specified office outside the United States, its territories and possessions will make payments of principal and interest in respect of Bearer Notes in accordance with the terms of the Indenture applicable to such Bearer Notes; provided, however, that:

(i) if any Temporary Global Note, Permanent Global Note, Definitive Bearer Note, Receipt or Coupon is presented or surrendered for payment to any Paying Agent and such Paying Agent has delivered a replacement therefor or has been notified that the same has been replaced, such Paying Agent should promptly notify the Company of such presentation or surrender and shall not make payment against the same until it is so instructed by the Company and has received the amount to be so paid;

(ii) a Paying Agent should not be obliged (but shall be entitled) to make payments of principal or interest in respect of the Bearer Notes, if it is not able to establish that the Trustee has received (whether or not at the due time) the full amount of any payment due to it;

(iii) the relevant Paying Agent should cancel or procure the cancellation of each Temporary Global Note, Permanent Global Note, Definitive Bearer Note (together, in the case of early redemption, with such unmatured Receipts or Coupons or unexchanged Talons as are attached to such Definitive Bearer Note at the time of such redemption), Receipt, Coupon or Talon, against surrender of which it has made full payment and should (if

such Paying Agent is not the Trustee) deliver or procure the delivery of each Temporary Global Note, Permanent Global Note, Definitive Bearer Note (together with, as aforesaid, such unmatured Receipts or Coupons or unexchanged Talons as are attached to or surrendered with the relevant Bearer Notes), Receipt, Coupon or Talon so cancelled by it to, or to the order of, the Trustee;

(iv) in the case of payment of interest, principal or, as the case may be, any other amount against presentation of a Temporary Global Note, the relevant Paying Agent should note or procure that there is noted on the schedule thereto (or, in the absence of a schedule, on the face thereof) the amount of such payment and, in the case of payment of principal, the remaining principal amount of the relevant Bearer Note (which shall be the previous principal amount less the principal which has then been paid) and shall procure the signature of such notation on its behalf;

(v) payments of principal and interest on Bearer Global Notes will be made in a manner specified in the relevant Bearer Global Notes against presentation or surrender, as the case may be, of such Bearer Global Note at the office of the relevant Paying Agent outside of the United States. A record of each payment of principal and any payment of interest will be made on each relevant Bearer Global Note by the relevant Paying Agent and such record will be prima facie evidence that the payment in question has been made absent manifest error; or

(vi) if the relevant Pricing Supplement specifies that rules substantially in the same form as United States Treasury Regulation §1.163-5(c)(2)(i)(D) for purposes of Section 4701 of the United States Internal Revenue Code of 1986, as amended (the "**D Rules**"), are applicable and the form of Notes as being "**Temporary Global Note exchangeable for a Permanent Global Note**" or "**Temporary Global Note exchangeable for Definitive Notes,**" interest will only be paid on a Temporary Global Note upon certification in accordance with Schedule 2 of the Indenture. In addition, no payments will be made under the Temporary Global Note following the Exchange Date unless exchange for interests in the Permanent Global Note is improperly withheld or refused.

Payments of principal and interest on Definitive Bearer Notes will be made against presentation or surrender, as the case may be, of such Definitive Bearer Note at the office of the relevant Paying Agent outside of the United States. Payments of interest in respect of Definitive Bearer Notes will be made only against surrender of Coupons and payments of principal will be made only against surrender of Receipts, in each case, at the office of the relevant Paying Agent outside of the United States.

Notwithstanding the provisions of Condition 3, if payments of interest and/or principal on a Bearer Note will be made in U.S. Dollars, such payments may be made in the United States if:

(1) the Company has appointed Paying Agents with specified offices outside the United States with the reasonable expectation that such Paying Agents would be able to make payment in U.S. Dollars at such specified offices outside the United States of the full amount of principal and interest on the Bearer Notes in the manner provided above when due;

(2) payment of the full amount of such principal and interest at all such specified offices outside the United States is illegal or effectively precluded by exchange controls or other similar restrictions on the full payment or receipt of principal and interest in U.S. Dollars; and

(3) such payment is then permitted under United States law without involving, in the opinion of the Company, adverse tax consequences to the Company.

A record of each payment of principal and any payment of interest will be made on each relevant Bearer Global Notes by the relevant Paying Agent and such record will be prima facie evidence that the payment in question has been made, absent manifest error.

No Paying Agent should exercise any Lien, right of set-off or similar claim against any person to whom it makes any payment under Condition 3 in respect thereof, nor shall any commission or expenses be charged by it to any such person in respect thereof.

If a Paying Agent makes any payment in accordance with Condition 3, it should notify the Trustee of the amount so paid by it, the serial number of the relevant Temporary Global Note, Permanent Global Note or Definitive Bearer Note against presentation or surrender of which payment of principal or interest was made and the number of Coupons by maturity against which payment of interest was made.

If at any time and for any reason a Paying Agent makes a partial payment in respect of a Temporary Global Note, Permanent Global Note, Definitive Bearer Note, Receipt or Coupon presented for payment to it, such Paying Agent should endorse thereon a statement indicating the amount and date of such payment.

(c) Unless another Business Day Convention is specified in the Pricing Supplement in any case where the date of payment of the principal of, or interest (including Additional Amounts), on the Notes shall not be a Business Day, then payment of principal or interest (including Additional Amounts) need not be made on such date at the relevant place of payment but may be made on the next succeeding Business Day. Any payment made on a date other than the date on which such payment is due as set forth herein shall have the same force and effect as if made on the date on which such payment is due, and no interest shall accrue for the period after such date.

(d) Interest in respect of any period of less than one year shall be calculated on the basis of the Day Count Fraction specified in the Pricing Supplement.

(e) All monies paid by or on behalf of the Company to the Trustee or to any Paying Agent for payment of the principal of, or interest (including Additional Amounts) on, any Note and not applied but remaining unclaimed for two years after the date upon which such amount shall have become due and payable shall be repaid to or for the account of the Company by the Trustee or such Paying Agent, the receipt of such repayment to be confirmed promptly in writing by or on behalf of the Company. The Holder or Holders of such Note or Notes shall thereafter look only to the Company for the payment that such Holder may be entitled to collect, and all liability of the Trustee or such Paying Agent with respect to such monies shall thereupon cease.

(f) If the Company at any time defaults in the payment of any principal of, or interest (including Additional Amounts) on, the Notes, the Company will pay interest on the amount in default (to the extent permitted by law in the case of interest on interest), calculated for each day until paid, at the rate per annum specified in the Pricing Supplement, together with Additional Amounts, if applicable.

(g) All payments of principal of, and premium, if any, and interest on the Notes will be made net of any deduction or withholding required by fiscal laws or regulations, and no Additional Amounts shall be paid with respect to any such deduction or withholding except as provided in Condition 4.

4. Taxation; Additional Amounts

All payments of principal of, and premium, if any, and interest on the Notes will be made without withholding or deduction for, or on account of, any present or future Taxes imposed or levied by or within any jurisdiction in which the Company or the Surviving Person (as defined under Condition 6) is organized or resident for tax purposes (or any political subdivision or taxing authority thereof or therein) or through which payment is made on behalf of the Company or the Surviving Person (each, a "**Relevant Jurisdiction**"), unless such withholding or deduction is required by law or by regulation or governmental policy having the force of law. In such event, the Company or the Surviving Person, as the case may be, will make such deduction or withholding, make payment of the amount so withheld to the appropriate governmental authority and will pay such additional amounts ("**Additional Amounts**") as will result in receipt by the Holder of such amounts as would have been received by such Holder had no such withholding or deduction been required, provided that no Additional Amounts will be payable with respect to:

(1) any Tax that would not have been imposed, payable or due but for:

(a) the existence of any present or former connection between the Holder (or the beneficial owner of, or person ultimately entitled to receive the payment on such Notes or if the Holder is an estate, nominee, trust, partnership or corporation, between a fiduciary, settler, beneficiary, partner of, member or shareholder of, or possessor of power over the Holder) and the Relevant Jurisdiction (including being a citizen or resident or national of, or carrying on a business or maintaining a permanent establishment in (including through a branch, agency or otherwise), or being physically present in, the Relevant Jurisdiction) other than the mere holding of the Notes or enforcement of rights thereunder or the receipt of payments in respect thereof;

(b) the failure of the Holder or beneficial owner to comply with a timely request of the Company or the Surviving Person, as the case may be, or the Paying Agent addressed to the Holder to provide information concerning such Holder's or beneficial owner's nationality, residence, identity or connection with any Relevant Jurisdiction, if and to the extent that due and timely compliance with such request would have reduced or eliminated any withholding or deduction as to which Additional Amounts would have otherwise been payable to such Holder or beneficial owner;

(c) the presentation of Notes (where presentation is required) for payment more than 30 days after the date such payment was due and payable or was duly provided for, whichever is later; or

(d) the presentation of such Note (in cases in which presentation is required) for payment in the Relevant Jurisdiction, unless such Note could not have been presented for payment elsewhere;

(2) any estate, inheritance, gift, sale, value added, use, excise, transfer, personal property or similar tax, assessment or other governmental charge;

(3) any withholding or deduction in respect of any Tax where such withholding or deduction is imposed or levied on a payment to an individual and is required to be made pursuant to European Council Directive 2003/48/EC or any other Directive implementing the conclusions of the ECOFIN Council meeting of November 26-27, 2000 on the taxation of savings income or any law implementing or complying with, or introduced in order to conform to, such Directive;

(4) any Tax which is payable otherwise than by deduction or withholding from payments of (or in respect of) principal of, premium, if any, or interest on the Notes;

(5) any withholding or deduction by or on behalf of a Holder of Notes who would have been able to avoid such deduction or withholding by presenting the relevant Note to another Paying Agent;

(6) any Tax which is imposed or required to be withheld under Sections 1471 to 1474 (or any successor provisions or amendments thereof) of the United States Internal Revenue Code of 1986, as amended, or pursuant to any agreements with the U.S. Internal Revenue Service or between the United States and the government of another country and any official pronouncements with respect thereto, or any law implementing an intergovernmental approach to such Sections; or

(7) any combination of Taxes referred to in the preceding clauses (1), (2), (3), (4), (5) and (6).

In addition, Additional Amounts will not be payable to a Holder that is a fiduciary, partnership, limited liability company or person other than the sole beneficial owner of any payment to the extent that such payment would be required to be included in the income under the laws of a Relevant Jurisdiction, for tax purposes, of a beneficiary or settlor with respect to the fiduciary, or a member of that partnership or limited liability company or a beneficial owner who would not have been entitled to such Additional Amounts had that beneficiary, settlor, partner, member or beneficial owner been the Holder thereof.

The Company or Surviving Person, as the case may be, will make any required withholding or deduction and remit the full amount deducted or withheld to the relevant authority in accordance with applicable law. The Company will make reasonable efforts to obtain certified copies of tax receipts evidencing the payment of any taxes so deducted or withheld from the Relevant Jurisdiction imposing such Taxes. The Company will furnish to the Trustee, within 60 days after the date the payment of any taxes so deducted or withheld is due pursuant to applicable law, either certified copies of tax receipts evidencing such payment or, if such receipts are not obtainable, other evidence of such payments.

Whenever in the Indenture or in the Conditions there is mentioned, in any context, the payment of amounts based upon the principal amount of the Notes or of principal, interest or of any other amount payable under or with respect to any of the Notes, such mention shall be deemed to include mention of the payment of Additional Amounts to the extent that, in such context, Additional Amounts are, were or would be payable in respect thereof.

5. Certain Covenants

For the purposes of this "Description of the Notes," the terms defined below have the following meanings:

"**Affiliate**" means, with respect to any Person, any other Person (i) directly or indirectly controlling, controlled by, or under direct or indirect common control with, such Person or (ii) who is a commissioner, director or officer of such Person or any Subsidiary of such Person or of any Person referred to in clause (i) of this definition. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with"), as applied to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract or otherwise.

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) in equity of such Person.

"**Change of Control**" means the occurrence of any event resulting in the government of the Republic of Indonesia ceasing to own and control (directly or indirectly or in combination) more than 50% of the Company's issued and paid-up shares.

"**Change of Control Triggering Event**" means a Change of Control, provided that, in the event that the Notes are, on the Rating Date, rated Investment Grade by two or more Rating Agencies, a Change of Control Triggering Event shall mean the occurrence of both a Change Of Control and a Rating Decline. No Change of Control Triggering Event will be deemed to have occurred in connection with any particular Change of Control unless and until such Change of Control has actually been consummated.

"**Clearstream**" means Clearstream Banking, société anonyme, Luxembourg or any successor thereof.

"**Debt**" means, with respect to any Person as of any date of determination, without duplication, (i) all obligations, contingent or otherwise, of such Person for borrowed money, (ii) all obligations of such Person evidenced by bonds, notes or other similar instruments, (iii) all obligations of such Person in respect of letters of credit or other similar instruments, (iv) all obligations of such Person to pay the unpaid purchase price of any property or service, (v) all obligations secured by a Lien on any property or asset of such Person, whether or not such obligations are assumed by such Person and (vi) all obligations of others guaranteed by such Person to the extent of such guarantees and, for clauses (i) through (vi), which has a final maturity of one year or more. The amount of Debt of any Person as of any date of determination shall be the outstanding balance at such date of all unconditional obligations as described above, the maximum liability of such Person for any such contingent obligations at such date and, in the case of clause (vi), the lesser of the fair market value (as determined in good faith by the board of directors of such Person) at such date of the property or asset of such Person subject to a Lien securing the obligations of others and the amount of such obligations secured.

"**Default**" means any event that is, or after notice or passage of time or both would be, an Event of Default.

"**Dollar Equivalent**" means, with respect to any monetary amount in a currency other than U.S. dollars, at any time for the determination thereof, the amount of U.S. dollars obtained by converting such foreign currency involved in such computation into U.S. dollars at the base rate for the purchase of U.S. dollars with the applicable foreign currency as quoted by the Federal Reserve Bank of New York on the date of determination.

"**DTC**" means The Depository Trust Company and its successors.

"**Euroclear**" means Euroclear Bank S.A./N.V. or any successor thereof.

"**Fitch**" means Fitch Ratings Ltd., and its successors.

"**guarantee**" means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Debt or other obligation of any other Person and, without limiting the generality of the foregoing, any obligation, direct or indirect, contingent or otherwise, of such Person (1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Debt or other

obligation of such other Person (whether arising by virtue of partnership arrangements, or by agreements to keep-well, to purchase assets, goods, securities or services, to take-or-pay, or to maintain financial statement conditions or otherwise) or (2) entered into for purposes of assuring in any other manner the obligee of such Debt or other obligation of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part); provided that the term "guarantee" will not include endorsements for collection or deposit in the ordinary course of business. The term "guarantee" used as a verb has a corresponding meaning.

"**IFAS**" means Indonesian Financial Accounting Standards.

"**Investment Grade**" means a rating of "AAA," "AA," "A" or "BBB," as modified by a "+" or "-" indication, or an equivalent rating representing one of the four highest Rating Categories, by S&P or any of its successors or assigns or a rating of "Aaa," or "Aa," "A" or "Baa," as modified by a "1," "2" or "3" indication, or an equivalent rating representing one of the four highest Rating Categories, by Moody's or any of its successors or assigns or a rating of "AAA," "AA," "A," or "BBB," as modified by a "+" or "-" indication, or an equivalent rating representing one of the four highest rating categories, by Fitch or any of its successors or assigns, or the equivalent ratings of any internationally recognized rating agency or agencies, as the case may be, which shall have been designated by the Company as having been substituted for S&P, Moody's or Fitch or two or three of them, as the case may be.

"**Issue Date**" means the date of issuance of the relevant Note.

"**Lien**" means any mortgage, pledge, security interest, encumbrance, lien or charge of any kind (including, without limitation, any conditional sale or other title retention agreement or lease in the nature thereof or any agreement to create any mortgage, pledge, security interest, lien, charge, easement or encumbrance of any kind but excluding liens arising by operation of law).

"**Moody's**" means Moody's Investors Service, Inc., and its successors.

"**Offer to Purchase**" means an offer to purchase Notes by the Company from the Holders commenced by the Company mailing a notice by first class mail, postage prepaid, to the Trustee and each Holder at its last address appearing in the Note register stating:

(a) the provision of the Indenture pursuant to which the offer is being made and that all Notes validly tendered will be accepted for payment on a pro rata basis;

(b) the purchase price and the date of purchase (which will be a Business Day no earlier than 30 days nor later than 60 days from the date such notice is mailed) (the "**Offer to Purchase Payment Date**");

(c) that any Note not tendered will continue to accrue interest pursuant to its terms;

(d) that, unless the Company defaults in the payment of the purchase price, any Note accepted for payment pursuant to the Offer to Purchase will cease to accrue interest on and after the Offer to Purchase Payment Date;

(e) that Holders electing to have a Note purchased pursuant to the Offer to Purchase will be required to surrender the Note, together with the form entitled "Option of the Holder to Elect Purchase" on the reverse side of the Note completed, to the Paying Agent at the address specified in the notice prior to the close of business on the Business Day immediately preceding the Offer to Purchase Payment Date;

(f) that Holders will be entitled to withdraw their election if the Paying Agent receives, not later than the close of business on the third Business Day immediately preceding the Offer to Purchase Payment Date, a facsimile transmission or letter setting forth the name of such Holder, the principal amount of Notes delivered for purchase and a statement that such Holder is withdrawing his election to have such Notes purchased;

(g) that Holders whose Notes are being purchased only in part will be issued new Notes equal in principal amount to the unpurchased portion of the Notes surrendered; provided that each Note purchased and each new Note issued will be in a principal amount of US$200,000 or integral multiples of US$1,000 in excess thereof; and

(h) the CUSIP number(s) and/or ISIN/Common code(s), as applicable, of the Notes.

One Business Day prior to the Offer to Purchase Payment Date, the Company will deposit with the Paying Agent money sufficient to pay the purchase price of all Notes or portions thereof to be accepted by the Company for payment on the Offer to Purchase Payment Date. On the Offer to Purchase Payment Date, the Company will (a) accept for payment on a pro rata basis Notes or portions thereof tendered pursuant to an Offer to Purchase; and (b) deliver, or cause to be delivered, to the Trustee all Notes or portions thereof so accepted together with an Officers' Certificate specifying the Notes or portions thereof accepted for payment by the Company. The Paying Agent will promptly mail to the Holders so accepted payment in an amount equal to the purchase price, and the Trustee will promptly authenticate and mail to such Holders a new Note equal in principal amount to any unpurchased portion of the Note surrendered; provided that each Note purchased and each new Note issued will be in a principal amount of US$200,000 or integral multiples of US$1,000 in excess thereof. The Company will publicly announce the results of an Offer to Purchase as soon as practicable after the Offer to Purchase Payment Date. The Company will comply with Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent such laws and regulations are applicable, in the event that the Company is required to repurchase Notes pursuant to an Offer to Purchase.

The offer is required to contain or incorporate by reference information concerning the business of the Company and its Subsidiaries which the Company in good faith believes will assist such Holders to make an informed decision with respect to the Offer to Purchase, including a brief description of the events requiring the Company to make the Offer to Purchase, and any other information required by applicable law to be included therein. The offer is required to contain all instructions and materials necessary to enable such Holders to tender Notes pursuant to the Offer to Purchase. To the extent that the provisions of any securities laws or regulations conflict with the requirements of the relevant Offer to Purchase, the Company will comply with the applicable securities laws and regulations and shall not be deemed to have breached their obligations under the Notes or the Indenture by virtue of their compliance with such securities laws or regulations.

"**Officer**" means one of the executive officers or directors of the Company.

"**Officers' Certificate**" means a certificate signed by two Officers.

"**Opinion of Counsel**" means a written opinion from legal counsel which opinion is acceptable to the Trustee that meets the requirements of the Indenture; provided that legal counsel shall be entitled to rely on a certificate of the Company as to matters of fact.

"**Person**" means any individual, corporation, partnership, limited liability company, joint venture, trust, unincorporated organization or government or any agency or political subdivision thereof.

"**Principal Property**" means any asset or property of the Company or a Subsidiary whether at the date of initial issuance of the Notes owned or thereafter acquired (other than any such asset or property, or portion thereof, reasonably determined by the Company not to be of material importance to the total business conducted by the Company and its Subsidiaries, taken as a whole).

"**Rating Agencies**" means (i) S&P, (ii) Moody's, (iii) Fitch and (iv) if one or more of S&P, Moody's or Fitch shall not make a rating of the Notes publicly available, a United States nationally recognized securities rating agency or agencies, as the case may be, selected by the Company, which shall be substituted for S&P, Moody's or Fitch or any combination thereof, as the case may be.

"**Rating Category**" means (i) with respect to S&P, any of the following categories: "BB," "B," "CCC," "CC," "C" and "D" (or equivalent successor categories); (ii) with respect to Moody's, any of the following categories: "Ba," "B," "Caa," "Ca, "C" and "D" (or equivalent successor categories); (iii) with respect to Fitch, any of the following categories: "BB," "B," "CCC," "CC," "C," or "D" (or equivalent successor categories); and (iv) the equivalent of any such category of S&P, Moody's or Fitch used by another Rating Agency. In determining whether the rating of the Notes has decreased by one or more gradations, gradations within Rating Categories ("+" and "-" for S&P; "1," "2" and "3" for Moody's; "+" and "-" for Fitch; or the equivalent gradations for another Rating Agency) shall be taken into account (e.g., with respect to S&P, a decline in a rating from "BB+" to "BB," as well as from "**BB-**" to "B+," will constitute a decrease of one gradation).

"**Rating Date**" means, in connection with a Change of Control Triggering Event, that date which is 90 days prior to the earlier of (i) a Change of Control and (ii) a public notice of the occurrence of a Change of Control.

"**Rating Decline**" means, in connection with a Change of Control Triggering Event, the occurrence on, or within 90 days after, the date, or public notice of the occurrence of, a Change of Control (which period shall be extended (by no more than an additional three months after the consummation of the Change of Control) so long as the rating of the Notes is under publicly announced consideration for possible downgrade by any of the Rating Agencies) of the following event: the Notes are (a) on the Rating Date rated Investment Grade by at least two Rating Agencies and (b) cease to be rated Investment Grade by at least two of such Rating Agencies.

"**S&P**" means Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc., and its successors.

"**Securities**" means bonds, debentures, notes or other similar securities having an original maturity of more than one year from its date of issue which (1) are, or are issued with the intention on the part of the issuer thereof that they should be, quoted, listed or ordinarily dealt in or traded on any stock exchange, over-the-counter or other securities market, and (2) either (A) are by their terms payable, or confer a right to receive payment, in any currency other than Rupiah or (B) are denominated in Rupiah and more than 50% of the aggregate principal amount of the offering of such international investment securities is initially distributed outside Indonesia by or with the Company's consent.

"**Stated Maturity**" means, (1) with respect to any Debt, the date specified in such debt security as the fixed date on which the final installment of principal of such Debt is due and payable as set forth in the documentation governing such Debt and (2) with respect to any scheduled installment of principal of or interest on any Debt, the date specified as the fixed date on which such installment is due and payable as set forth in the documentation governing such Debt.

"**Subsidiary**" means (i) any corporation or other entity of which securities or other ownership interests having ordinary voting power to elect a majority of the board of directors or other persons performing similar functions are at the time directly or indirectly owned by the Company or (ii) any subsidiary subject to consolidation with the Company's financial statements under IFAS.

"**Tax**" shall mean any tax, duty, levy, impost, assessment or other governmental charge (including penalties, interest and any other liabilities related thereto).

"**U.S. Government Obligations**" means securities that are (1) direct obligations of the United States of America for the payment of which its full faith and credit is pledged or (2) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States of America, which, in either case, are not callable or redeemable at the option of the issuer thereof at any time prior to the Stated Maturity of the Notes, and will also include a depository receipt issued by a bank or trust company as custodian with respect to any such U.S. Government Obligation or a specific payment of interest on or principal of any such U.S. Government Obligation held by such custodian for the account of the holder of a depository receipt; provided that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depository receipt from any amount received by the custodian in respect of the U.S. Government Obligation or the specific payment of interest on or principal of the U.S. Government Obligation evidenced by such depository receipt.

"**Wholly Owned**" means, with respect to any Subsidiary of any Person, the ownership of all of the outstanding Capital Stock of such Subsidiary by such Person or one or more Wholly Owned Subsidiaries of such Person.

5A. Change of Control

Not later than 30 days following a Change of Control Triggering Event, the Company will make an Offer to Purchase all Outstanding Notes (a "**Change of Control Offer**") at a purchase price equal to 101% of the principal amount thereof plus accrued and unpaid interest, if any, to the Offer to Purchase Payment Date.

The Company has agreed in the Indenture that it will timely repay all Debt or obtain consents as necessary under, or terminate, agreements or instruments that would otherwise prohibit a Change of Control Offer required to be made pursuant to the Indenture. Notwithstanding these agreements, it is important to note that if the Company is unable to repay (or cause to be repaid) all of the Debt, if any, that would prohibit the repurchase of the Notes or is unable to obtain the requisite consents of the holders of such Debt, or terminate any agreements or instruments that would otherwise prohibit a Change of Control Offer, the Company would continue to be prohibited from purchasing the Notes. In that case, the failure of the Company to purchase tendered Notes would constitute an Event of Default under the Indenture.

Certain of the events constituting a Change of Control Triggering Event under the Notes will also constitute an event of default under certain debt instruments of the Company and its Subsidiaries. Future Debt of the Company or its Subsidiaries may also (1) prohibit the Company from purchasing the Notes in the event of a Change of Control Triggering Event; (2) provide that a Change of Control Triggering Event is a default; or (3) require the repayment or repurchase of such Debt upon a Change of Control Triggering Event. Moreover, the exercise by the Holders of their right to require the Company to purchase the Notes could cause a default under other Debt,

even if the Change of Control Triggering Event itself does not, due to the financial effect of the purchase on the Company or its Subsidiaries. The ability of the Company to pay cash to Holders of the Notes following the occurrence of a Change of Control Triggering Event may be limited by the financial resources then available to the Company. There can be no assurance that sufficient funds will be available when necessary to make the required purchase of the Notes.

Except as described above with respect to a Change of Control Offer, the Indenture does not contain provisions that permit the Holders to require that the Company purchase or redeem the Notes in the event of a takeover, recapitalization or similar transaction.

5B. Negative Pledge

So long as any of the Notes are Outstanding, the Company will not create or permit to subsist, and the Company will ensure that none of its Subsidiaries that own a Principal Property (each, a "**Material Subsidiary**") will create or permit to subsist, any Lien for the benefit of the holders of any Securities upon the whole or any part of its property or assets, present or future, to secure: (i) payment of any sum due in respect of any Securities; (ii) any payment under any guarantee of any Securities; or (iii) any indemnity or other like obligation in respect of any Securities, without in any such case (x) at the same time according to the Notes the same Liens as are granted to or are outstanding in respect of such Securities or (y) providing such other Lien for the Notes as may be approved by the holders of the Notes; provided, however, that the foregoing restriction shall not apply to:

(a) any Lien existing at the time of acquisition of any property by the Company provided that such Lien was not created in contemplation of such acquisition or in connection therewith and the principal, capital or nominal amount of the indebtedness secured by such Lien outstanding at the time of such acquisition is not increased; or

(b) any Lien arising out of the refinancing, extension or renewal, in whole or in part, of a Lien permitted under clause (a) above or any Securities secured by any Lien permitted by the preceding clause, to the extent of the amount of such Securities; provided that such Securities are not secured by any additional property or assets.

5C. Reports

For so long as any of the Notes remain Outstanding, the Company will file with the Trustee:

(a) as soon as they are available, but in any event within 120 calendar days after the end of its fiscal year, copies of its financial statements (on a consolidated basis) in respect of such financial year (including a statement of income, balance sheet and cash flow statement) audited by a member firm of an internationally recognized firm of independent accountants;

(b) as soon as they are available, but in any event within 60 calendar days after the end of each of its first, second and third fiscal quarters, copies of its financial statements (on a consolidated basis) in respect of such period (including a statement of income, balance sheet and cash flow statement) prepared on a basis consistent with its audited financial statements, together with a certificate signed by the Person then authorized to sign financial statements on behalf of it, to the effect that such financial statements are true in all material respects and present fairly its financial position as at the end of, and the results of its operations for, the relevant quarterly period; and

(c) promptly and in any event within 15 days after it obtains actual knowledge of the occurrence thereof, written notice of the occurrence of any event or condition which constitutes an Event of Default and an Officer's Certificate setting forth the details thereof and the action it is taking or proposes to take with respect thereto.

Further, the Company has agreed that, for so long as any Notes are "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act, during any period in which the Company is neither subject to Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), nor exempt from reporting pursuant to Rule 12g3-2(b) thereunder, the Company will supply to (i) any Holder or beneficial owner of a Note or (ii) a prospective purchaser of a Note or a beneficial interest therein designated by such Holder or beneficial owner, the information specified in, and meeting the requirements of Rule 144A(d)(4) under the Securities Act upon the request of any Holder or beneficial owner of a Note.

5D. Use of Proceeds

The Company will not use the net proceeds from the sale of any Tranche of Notes, in any material amount, for any purpose other than for the purposes specified under the caption "Use of Proceeds" in the Offering Memorandum or as set forth in the applicable Pricing Supplement.

5E. Payment of Stamp Duties and Other Taxes

The Company will pay any present or future stamp, court or documentary duties or taxes, or any other excise or property taxes, charges or similar levies which arise under the laws of the Republic of Indonesia, or the United States or any political subdivision or taxing authority thereof respectively, from the execution, delivery, registration, enforcement, redemption or retirement of the Notes or any other document or instrument relating thereto.

5F. Listing of the Program

The Company shall make such filings, registrations or qualifications and take all other necessary action and will use its best efforts to obtain such consents, approvals and authorizations, if any, and satisfy all conditions that the SGX-ST may impose on the listing of the Program.

5G. No Payments for Consents

The Company will not, and will not permit any of its Subsidiaries to, directly or indirectly, pay or cause to be paid any consideration, whether by way of interest, fee or otherwise, to any Holder for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes, unless such consideration is offered to be paid or is paid to all Holders that consent, waive or agree to amend such term or provision within the time period set forth in the solicitation documents relating to such consent, waiver or amendment.

6. Limitations on Consolidation, Merger and Sale of Assets

The Company will not consolidate with, merge with or into another Person, permit any Person to merge with or into it, or sell, convey, transfer, lease or otherwise dispose of all or

substantially all of its properties and assets, computed on a consolidated basis with its Subsidiaries, (as an entirety or substantially an entirety in one transaction or a series of related transactions), unless:

(1) the Company will be the continuing Person, or the Person (if other than it) formed by such consolidation or merger or that acquired or leased such property and assets (the "**Surviving Person**") will be a corporation organized and validly existing under the laws of the jurisdiction in which it is organized and will expressly assume, by a supplemental indenture to the Indenture, executed and delivered to the Trustee, all the obligations of the Company under the Indenture and the Notes, including the obligation to pay Additional Amounts, and the Indenture and the Notes will remain in full force and effect;

(2) immediately after giving effect to such transaction, no Default or Event of Default will have occurred and be continuing; and

(3) the Company delivers to the Trustee an Officers' Certificate and an Opinion of Counsel, in each case stating that such consolidation, merger or transfer and the relevant supplemental indenture complies with this provision and that all conditions precedent provided for in the Indenture relating to such transaction have been complied with and that the relevant supplemental indenture is enforceable.

For purposes of this covenant, the conveyance, transfer or lease of all or substantially all of the property or assets of one or more Subsidiaries of the Company, which constitutes all or substantially all of the property or assets of the Company and its Subsidiaries on a consolidated basis, shall be deemed to be the transfer of all or substantially all of the property or assets of the Company.

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the property or assets of a Person.

The foregoing provisions would not necessarily afford Holders protection in the event of highly-leveraged or other transactions involving the Company that may adversely affect Holders.

7. Events of Default

Each of the following is an "**Event of Default**":

(1) default in the payment of principal of (or premium, if any, on) the Notes when the same becomes due and payable at maturity, upon acceleration, redemption or otherwise;

(2) default in the payment of interest on any Note when the same becomes due and payable, and such default continues for a period of 30 days;

(3) default in the performance of or breaches of the provisions of the covenants described under Condition 6 or failure to make or consummate an Offer to Purchase in the manner described under Condition 5A (Change of Control);

(4) default in the performance of or breaches of any other covenant or agreement in the Indenture or under the Notes (other than a default specified in clause (a), (b) or (c) above) and such default or breach continues for a period of 60 consecutive days after written notice by the Trustee or the Holders of 25% or more in aggregate principal amount of the outstanding Notes;

(5) there occurs with respect to any Debt of the Company or any of its Material Subsidiaries having an outstanding principal amount of US$50.0 million (or the Dollar Equivalent thereof) or more in the aggregate for all such Debt of all such Persons, whether such Debt now exists or will hereafter be created, (A) an event of default that has caused the holder thereof to declare such Debt to be due and payable prior to its Stated Maturity or (B) the failure to make a payment of principal (subject to the applicable grace period in the relevant documents) of such Debt when the same becomes due;

(6) one or more final judgments or orders for the payment of money are rendered against the Company or any of its Material Subsidiaries and are not paid or discharged, and there is a period of 60 consecutive days following entry of the final judgment or order that causes the aggregate amount for all such final judgments or orders outstanding and not paid or discharged against all such Persons to exceed US$50.0 million (or the Dollar Equivalent thereof) during which a stay of enforcement, by reason of a pending appeal or otherwise, is not in effect;

(7) an involuntary case or other proceeding is commenced against the Company or any Material Subsidiary with respect to it or its debts under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect seeking the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Company or any Material Subsidiary or for any substantial part of the property and assets of the Company or any Material Subsidiary and such involuntary case or other proceeding remains undismissed and unstayed for a period of 60 consecutive days; or an order for relief is entered against the Company or any Material Subsidiary under any applicable bankruptcy, insolvency or other similar law as now or hereafter in effect; or

(8) the Company or any Material Subsidiary (i) commences a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consents to the entry of an order for relief in an involuntary case under any such law, (ii) consents to the appointment of or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Company or any Material Subsidiary or for all or substantially all of the property and assets of the Company or any Material Subsidiary or (iii) effects any general assignment for the benefit of creditors.

If an Event of Default (other than an Event of Default specified in Condition 7(7) or Condition 7(8) above) occurs and is continuing under the Indenture, the Trustee or the Holders of at least 25% in aggregate principal amount of the Notes, then Outstanding, by written notice to the Company (and to the Trustee if such notice is given by the Holders), may, and the Trustee at the written request of such Holders will, declare the principal of, premium, if any, and accrued and unpaid interest on the Notes to be immediately due and payable. Upon a declaration of acceleration, such principal of, premium, if any, and accrued and unpaid interest will be immediately due and payable. If an Event of Default specified in Condition 7(7) or Condition 7(8) above occurs, the principal of, premium, if any, and accrued and unpaid interest on the Notes then Outstanding will automatically become and be immediately due and payable without any declaration or other act on the part of the Trustee or any Holder.

The Holders of at least a majority in principal amount of the Outstanding Notes by written notice to the Company and the Trustee, may on behalf of all of the Holders waive all past defaults and rescind and annul a declaration of acceleration and its consequences with respect to the Notes if:

(i) the Company pays or deposits with the Trustee a sum sufficient to pay all monies then due with respect to the Notes (other than amounts due solely because of such declaration of acceleration) and all other existing Events of Default have been cured or waived, and

(ii) the rescission would not conflict with any judgment or decree of a court of competent jurisdiction.

Upon such waiver, the Default will cease to exist, and any Event of Default arising therefrom will be deemed to have been cured, but no such waiver will extend to any subsequent or other Default or impair any right consequent thereon.

The Holders of at least a majority in aggregate principal amount of the Outstanding Notes may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee. However, the Trustee may refuse to follow any direction that conflicts with law or the Indenture, that may involve the Trustee in personal liability, or that the Trustee determines in good faith may be unduly prejudicial to the rights of Holders not joining in the giving of such direction and may take any other action it deems proper that is not inconsistent with any such direction received from Holders.

A Holder may not pursue or institute any proceeding, judicial or otherwise, with respect to the Indenture or the Notes, or for the appointment of a receiver or trustee, or for any other remedy under the Indenture or the Notes, unless:

(a) the Holder has previously given the Trustee written notice of a continuing Event of Default;

(b) the Holders of at least 25% in aggregate principal amount of Outstanding Notes make a written request to the Trustee to pursue the remedy;

(c) such Holder or Holders offer the Trustee indemnity and/or security and/or prefunding satisfactory to the Trustee against any costs, liability or expense to be incurred in compliance with such request;

(d) the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity; and

(e) during such 60-day period, the Holders of a majority in aggregate principal amount of the Outstanding Notes do not give the Trustee a direction that is inconsistent with the request.

However, such limitations do not apply to the right of any Holder of a Note to receive payment of the principal of, premium, if any, or interest, and Additional Amounts, if any, on, such Note or to bring suit for the enforcement of any such payment, on or after the due date expressed in the Notes, which right will not be impaired or affected without the consent of the Holder.

Officers of the Company must certify to the Trustee, on or before a date not more than 120 calendar days after the end of each fiscal year, that a review has been conducted of the activities of the Company and its Subsidiaries and the Company's performance under the Indenture and the Notes and that the Company has fulfilled all obligations thereunder, or, if there has been a default in the fulfillment of any such obligation, specifying each such default and the nature and status thereof. The Company will also be obligated to notify the Trustee in writing of any default or defaults in the performance of any covenants or agreements under the Indenture. See Condition 5C (Reports).

8. Redemption

(a) Redemption by Installments and Final Redemption:

(i) Unless previously redeemed, purchased and cancelled each Note that provides for Installment Dates and Installment Amounts shall be partially redeemed on each Installment Date at the related Installment Amount specified in the Pricing Supplement. The outstanding nominal amount of each such Note shall be reduced by the Installment Amount (or, if such Installment Amount is calculated by reference to a proportion of the nominal amount of such Note, such proportion) for all purposes with effect from the related Installment Date, unless payment of the Installment Amount is improperly withheld or refused, in which case, such amount shall remain outstanding until the Relevant Date relating to such Installment Amount.

(ii) Unless previously redeemed, purchased and cancelled as provided below, each Note shall be finally redeemed on the Maturity Date specified in the Pricing Supplement at its Final Redemption Amount (which, unless otherwise provided in the Pricing Supplement, is its nominal amount) or, in the case of a Note falling within Condition 8(a)(i) above, its final installment Amount.

(b) Early Redemption:

(i) *Zero Coupon Notes*:

(A) The Early Redemption Amount payable in respect of any Zero Coupon Note, the Early Redemption Amount of which is not linked to an index and/or a formula, upon redemption of such Note pursuant to Condition 8(c) or upon it becoming due and payable as provided in Condition 7 shall be the Amortized Face Amount (calculated as provided below) of such Note unless otherwise specified in the Pricing Supplement.

(B) Subject to the provisions of Condition 8(b)(i)(C) below, the Amortized Face Amount of any such Note shall be the scheduled Final Redemption Amount of such Note on the Maturity Date discounted at a rate per annum (expressed as a percentage) equal to the Amortization Yield (which, if none is shown in the Pricing Supplement, shall be such rate as would produce an Amortized Face Amount equal to the issue price of the Notes if they were discounted back to their issue price on the Issue Date) compounded annually.

(C) If the Early Redemption Amount payable in respect of any such Note upon its redemption pursuant to Condition 8(c) or upon it becoming due and payable as provided in Condition 7 is not paid when due, the Early Redemption Amount

due and payable in respect of such Note shall be the Amortized Face Amount of such Note as defined in Condition 8(b)(i)(B) above, except that such Condition shall have effect as though the date on which the Note becomes due and payable were the Relevant Date. The calculation of the Amortized Face Amount in accordance with this Condition 8(b)(i)(C) shall continue to be made (both before and after judgment) until the Relevant Date, unless the Relevant Date falls on or after the Maturity Date, in which case the amount due and payable shall be the scheduled Final Redemption Amount of such Note on the Maturity Date together with any interest that may accrue in accordance with Condition 7.

Where such calculation is to be made for a period of less than one year, it shall be made on the basis of the Day Count Fraction shown in the Pricing Supplement.

(ii) *Other Notes*: The Early Redemption Amount payable in respect of any Note (other than Notes described in (i) above), upon redemption of such Note pursuant to Condition 8(c) or upon it becoming due and payable as provided in Condition 7, shall be the Final Redemption Amount unless otherwise specified in the Pricing Supplement.

(c) Redemption for Taxation Reasons:

The Notes may be redeemed, at the option of the Company or the Surviving Person, as the case may be, in whole but not in part, on any Interest Payment Date (if the Note is either a Floating Rate Note or an Index Linked Note) or at any time (if the Note is neither a Floating Rate Note nor an Index Linked Note), upon giving not less than 30 days' and not more than 60 days' notice to the Holders (which notice shall be irrevocable), at a redemption price equal to 100% of the principal amount thereof, together with accrued and unpaid interest (including any Additional Amounts), if any, to the date fixed by the Company or the Surviving Person, as the case may be, for redemption if, as a result of:

(i) any change in, or amendment to, the laws (or any regulations or rulings promulgated thereunder) of a Relevant Jurisdiction affecting taxation; or

(ii) any change in the existing official position regarding the application or interpretation of, or the stating of an official position regarding the application or interpretation of, such laws, regulations or rulings (including a holding, judgment or order by a court of competent jurisdiction),

which change or amendment becomes effective on or after (i) in the case of the Company, the Issue Date, or (ii) in the case of a Surviving Person, the date on which the Surviving Person assumes the obligations of the Company under the Indenture and the Notes, the Company or the Surviving Person, as the case may be, is, or on the next date of interest payment on the Notes would be, required to pay Additional Amounts with respect to any payment due or to become due under the Notes or the Indenture, and such requirement cannot be avoided by the taking of reasonable measures (including an appointment of a new paying agent) by the Company or the Surviving Person, as the case may be (provided that changing the jurisdiction of the Company or a Surviving Person, as the case may be, is not a reasonable measure for purposes of this section); provided that no such notice of redemption shall be given earlier than 90 days prior to the earliest date on which the Company or the Surviving Person, as the case may be, would be obligated to pay such Additional Amounts if a payment in respect of the Notes were then due; provided further

that where any such requirement to pay Additional Amounts is due to taxes of the Republic of Indonesia (or any political subdivision or taxing authority thereof or therein), the Company or the Surviving Person shall be permitted to redeem the Notes in accordance with the provisions above only if the rate of withholding or deduction so required is in excess of 20.0% (the "**Minimum Withholding Level**"). No less than 15 days (or such period as may be agreed between the Company or the Surviving Person, as the case may be, and the Trustee) before giving such notice, the Company or the Surviving Person, as the case may be, shall give notice to the Principal Paying Agent and in the case of a redemption of Registered Notes, the Registrar (which notices shall be irrevocable and shall specify the date fixed for redemption).

Prior to the publication and mailing of any notice of redemption of the Notes pursuant to the foregoing, the Company or the Surviving Person, as the case may be, will deliver to the Trustee:

(1) an Officers' Certificate stating that such change or amendment referred to in the prior paragraph has occurred, describing the facts related thereto and stating that such requirement cannot be avoided by the Company or the Surviving Person, as the case may be, by taking reasonable measures available to it;

(2) an Opinion of Counsel or an opinion of a tax consultant of recognized standing with respect to such matter, or a copy of any judicial decision or regulatory determination or ruling, in each case to the effect that the requirement to pay such Additional Amounts results from such change or amendment referred to in the prior paragraph; and

(3) in the case of a redemption where the Minimum Withholding Level has been exceeded, an Opinion of Counsel or an opinion of a tax consultant of recognized standing with respect to such matter that the Company or the Surviving Person, as the case may be, has or will become obliged to pay Additional Amounts exceeding the Minimum Withholding Level.

The Trustee shall accept such certificate and opinion as sufficient evidence of the satisfaction of the conditions precedent described above, in which event it shall be conclusive and binding on the Holders.

(d) Redemption at the Option of the Company:

If Call Option is specified in the Pricing Supplement, the Company or the Surviving Person, as the case may be, may, on giving not less than 20 nor more than 30 days' irrevocable notice to the Holders (or such other notice period as may be specified in the Pricing Supplement) redeem all or, if so provided, some of the Notes on any Optional Redemption Date. No less than 15 days (or such period as may be agreed between the Company or the Surviving Person, as the case may be, and the Trustee) before giving such notice, the Company or the Surviving Person, as the case may be, shall give notice to the Principal Paying Agent and in the case of a redemption of Registered Notes, the Registrar (which notices shall be irrevocable and shall specify the date fixed for redemption). Any such redemption of Notes shall be at their Optional Redemption Amount together with interest accrued to the date fixed for redemption. Any such redemption or exercise must relate to Notes of a nominal amount at least equal to the Minimum Redemption Amount to be redeemed specified in the Pricing Supplement and no greater than the Maximum Redemption Amount to be redeemed specified in the Pricing Supplement.

All Notes in respect of which any such notice is given shall be redeemed on the date specified in such notice in accordance with this Condition 8(d).

In the case of a partial redemption, the notice to Holders shall, in the case of Bearer Notes, also contain the certificate numbers of the Bearer Notes or, in the case of Registered Notes, specify the nominal amount of Registered Notes selected and the holder(s) of such Registered Notes, to be redeemed, which shall have been selected in such place as the Trustee may approve and in such manner as it deems appropriate, subject to compliance with any applicable laws and stock exchange or other relevant authority requirements.

(e) Redemption at the Option of Holders:

If Put Option is specified in the Pricing Supplement, the Company or the Surviving Person, as the case may be, shall, at the option of the holder of any such Note, upon the holder of such Note giving not less than 15 nor more than 30 days' notice to the Company (or such other notice period as may be specified in the Pricing Supplement) redeem such Note on the Optional Redemption Date(s) at its Optional Redemption Amount together with interest accrued to the date fixed for redemption.

To exercise such option the holder must deposit a duly completed option exercise notice in the form obtainable from any Paying Agent, the Registrar or any Transfer Agent (as applicable) within the notice period with the Registrar or any Transfer Agent at its specified office, in the case of Definitive Notes together with the relevant Definitive Note representing such Note(s). No Note so deposited and option exercised may be withdrawn without the prior consent of the Company.

(f) Partly Paid Notes:

Partly Paid Notes will be redeemed, whether at maturity, early redemption or otherwise, in accordance with the provisions of this Condition 8 and the provisions specified in the Pricing Supplement.

9. Replacement, Exchange and Transfer of Notes

(a) Upon the terms and subject to the conditions set forth in the Indenture, in case any Note shall become mutilated, defaced or be apparently destroyed, lost or stolen, the Company will execute, and upon the request of the Company, the Trustee or the Registrar, as applicable, shall authenticate and deliver, a new Note bearing a number not contemporaneously Outstanding, in exchange and substitution for the mutilated or defaced Note, or in lieu of and in substitution for the apparently destroyed, lost or stolen Note. In every case, the applicant for a substitute Note shall furnish to the Company and to the Trustee such security and/or indemnity as may be required by each of them to indemnify, defend and to save each of them and any agent of the Company or the Trustee harmless and, in every case of destruction, loss or theft, evidence to their satisfaction of the apparent destruction, loss or theft of such Note and of the ownership thereof. Upon the issuance of any substitute Note, the Holder of such Note, if so requested by the Company, shall pay a sum sufficient to cover any stamp duty, tax or other governmental charge that may be imposed in relation thereto and any other expenses (including the fees and expenses of the Trustee and counsel to the Trustee) connected with the preparation and issuance of the substitute Note.

(b) Upon the terms and subject to the conditions set forth in the Indenture, and subject to Condition 9(e), a Definitive Note may be exchanged for an equal aggregate principal amount of Definitive Notes in different Specified Denominations by the Holder or Holders surrendering the Note or Notes for exchange at the Corporate Trust Office of the Trustee in The City of New York or at the office of a transfer agent, together with a written request for the exchange. Definitive Notes will only be issued in exchange for interests in a Registered Global Security pursuant to Clauses 2.6.6 through 2.6.10 of the Indenture. The exchange of the Notes will be made by the Trustee in The City of New York.

(c) Upon the terms and subject to the conditions set forth in the Indenture, and subject to Condition 9(e), a Certificated Security may be transferred in whole or in a smaller Specified Denomination by the Holder or Holders surrendering the Certificated Security for transfer at the Corporate Trust Office of the Trustee in The City of New York or at the office of a Paying Agent accompanied by an executed instrument of transfer substantially as set forth in Exhibit K to the Indenture. The registration of transfer of the Notes will be made by the Trustee in The City of New York.

(d) The costs and expenses of effecting any exchange, transfer or registration of transfer pursuant to this Condition 9 will be borne by the Company, except for the expenses of delivery (if any) not made by regular mail and the payment of a sum sufficient to cover any stamp duty, transfer tax or other governmental charge or insurance charge that may be imposed in relation thereto, which will be borne by the Holder.

(e) The Trustee may decline to accept any request for an exchange or registration of transfer of any Registered Note during the period of 15 days preceding the due date for any payment of principal of or interest on the Registered Notes.

10. Trustee

For a description of the duties and the immunities and rights of the Trustee under the Indenture, reference is made to the Indenture, and the obligations of the Trustee to the Holder of a Note are subject to such immunities and rights.

Subject to the provisions of the Indenture, the Trustee will be under no obligation to exercise any of the rights or powers under the Indenture unless indemnity and/or security and/or prefunding satisfactory to the Trustee against any loss, liability or expense shall have been offered to the Trustee.

11. Paying Agents; Transfer Agents; Registrar

The Company has initially appointed the Paying Agents, transfer agents and registrar. The Company may at any time appoint additional or other Paying Agents, transfer agents and, with respect to Registered Notes, registrars and terminate the appointment of those or any Paying Agents, transfer agents and registrar, provided that while the Notes are Outstanding the Company will maintain in London and, with respect to Registered Notes, New York City (i) a Paying Agent, (ii) an office or agency where the Notes may be presented for exchange, transfer and registration of transfer as provided in the Indenture and (iii) with respect to Registered Notes, a registrar. In addition, if and for so long as the Notes are listed on the SGX-ST and the rules of such exchange so require, the Company will maintain a Paying Agent and Transfer Agent in Singapore. Notice of any such termination or appointment and of any change in the office through which any Paying Agent, transfer agent or registrar will act will be promptly given in the manner described in Condition 13.

12. Enforcement

Subject to Clause 4.6 of the Indenture, a Holder may not pursue or institute any proceeding, judicial or otherwise, with respect to the Indenture or the Notes, or for the appointment of a receiver or trustee, or for any other remedy under the Indenture or the Notes, unless:

(a) the Holder has previously given the Trustee written notice of a continuing Event of Default;

(b) the Holders of at least 25% in aggregate principal amount of Outstanding Notes make a written request to the Trustee to pursue the remedy;

(c) such Holder or Holders offer the Trustee indemnity and/or security and/or prefunding satisfactory to the Trustee against any costs, liability or expense to be incurred in compliance with such request;

(d) the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity; and

(e) during such 60-day period, the Holders of a majority in aggregate principal amount of the Outstanding Notes do not give the Trustee a direction that is inconsistent with the request.

13. Notices

Notices by the Company will be in writing in the English language and will be mailed to Holders of Notes at their registered addresses and shall be deemed to have been given on the date of such mailing. So long as the Notes are listed on the SGX-ST and the rules of the exchange so require, notices to Holders will be valid if published in a daily newspaper having general circulation in Singapore (which is expected to be The Business Times). Any such notice shall be deemed to have been given on the date of such publication, or if published more than once, on the first date on which publication is made. If publication is not practicable, the Company will have validly given notice if it gives notice in accordance with the rules of the SGX-ST.

14. Further Issues of Notes

The Company may, without the consent of the Holders, create and issue additional Notes with the same terms and conditions as the Notes (or that are the same except for the amount of the first interest payment and for the interest paid on the Notes prior to the issuance of the additional Notes). The Company may consolidate additional Registered Notes with the Outstanding Notes to form a single Series, provided that such additional Registered Notes will not have the same CUSIP number, ISIN number, Common Code or other identifying number as the Outstanding Notes unless the additional Notes are fungible with the Outstanding Notes for U.S. federal income tax purposes; provided further that in the case of Bearer Notes to which the D Rules apply that are initially represented by interests in a Temporary Global Note exchangeable for interest in a Permanent Global Note or Definitive Notes, such consolidation can only occur following the exchange of interests in the Temporary Global Note for interests in the Permanent Global Note or Definitive Notes upon certification of non-U.S. beneficial ownership.

15. No Sinking Fund

The Notes will not be subject to any sinking fund.

16. Authentication

A Note shall not become valid or obligatory until the certificate of authentication hereon shall have been duly signed by the Trustee or its agent.

17. Governing Law; Agent for Service; Submission to Jurisdiction; Waiver of Immunity

(a) The Notes will be governed by and interpreted in accordance with the laws of the State of New York.

(b) The Company hereby irrevocably submits to the non-exclusive jurisdiction of any New York State or United States Federal Court located in the Borough of Manhattan, The City of New York, over any suit, action or proceeding arising out of or relating to the Indenture or any Note. The Company hereby irrevocably waives, to the fullest extent permitted by law, any objection which it may now or hereafter have to the laying of venue of any such suit, action or proceeding brought in such courts and any claim that any such suit, action or proceeding brought in such courts has been brought in an inconvenient forum. To the extent that the Company has or hereafter may acquire any immunity from jurisdiction of any court or from any legal process with respect to itself or its property, the Company hereby irrevocably waives such immunity in respect of its obligations under the Indenture and any Note. The Company agrees that final judgment in any such suit, action or proceeding brought in such a court shall be conclusive and binding on the Company and, to the extent permitted by applicable law, may be enforced in any court to the jurisdiction of which the Company, as the case may be, is subject by a suit upon such judgment or in any manner provided by law; provided that service of process is effected upon the Company, as the case may be, in the manner specified in the following paragraph or as otherwise permitted by law.

(c) As long as any of the Notes remain outstanding, the Company shall at all times have an authorized agent in New York City upon whom process may be served in any legal action or proceeding arising out of or relating to this Indenture or any Note. Service of process upon such agent and written notice of such service mailed or delivered to the Company, as the case may be, shall to the fullest extent permitted by law be deemed in every respect effective service of process upon the Company in any such legal action or proceeding. The Company has appointed Corporation Service Company as its agent for such purpose, and covenants and agrees that service of process in any suit, action or proceeding may be made upon it at the office of such agent at 1180 Avenue of the Americas, Suite 210, New York, New York 10036 (or at such other address or at the office of such other authorized agent as the Company, as the case may be, may designate by written notice to the Trustee from time to time).

(d) The Company will not bring any claim or otherwise initiate any legal action in any court or other tribunal in Indonesia against the Trustee, any Agents or any Holder of the Notes (in their capacity as a Holder of the Notes) on the basis that any offering of the Notes by the Company, the Indenture, any purchase agreements entered into by the Company in relation to the issue and sale of the Notes by the Issuer under the Indenture or any transaction contemplated thereby is or was invalid or illegal under any Indonesian law, regulation, court order or decree or was induced in any way by fraud, manipulation, legal manufacturing, fiction, fabrication or other deceptive means.

18. Purchases of Notes by the Company

The Company may at any time purchase or acquire any of the Notes in any manner and at any price. The Notes which are purchased or acquired by the Company may, at the Company's discretion, be held, resold or surrendered to the Trustee for cancellation.

19. Amendment, Supplement and Waiver

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders under the Indenture and the Notes at any time by the Company and the Trustee with the consent of the Holders of a majority in aggregate principal amount of the Notes at the time Outstanding. The Indenture also contains provisions permitting the Holders of a majority in aggregate principal amount of the Notes at the time Outstanding, on behalf of the Holders of all Notes, to waive compliance by the Company with certain provisions of the Indenture and the Notes and certain past defaults under the Indenture and their consequences. Any such consent or waiver by or on behalf of the Holder of the Note shall be conclusive and binding upon such Holder and upon all future Holders of the Note and of any Note issued upon the registration of transfer hereof or in exchange herefor or in lieu hereof whether or not notation of such consent or waiver is made upon the Note. Subject to the foregoing, the Indenture and the Notes may be amended by the Company and the Trustee, without the consent of any Holder, for the purpose of, among other things, curing any ambiguity, omission, defect or inconsistency, adding guarantees with respect to the Notes or to secure the Notes or making any change that does not adversely affect the rights of any Holder of the Notes.

No reference herein to the Indenture and no provision of the Note or of this Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of (and premium, if any) and interest and Additional Amount on the Note at the times, place, and rate, and in currency, herein prescribed.

20. Transfers

(a) Restricted Global Security

Unless otherwise specified in the applicable Pricing Supplement, if (1) the owner of a beneficial interest in a Restricted Global Security wishes to transfer such interest (or portion thereof) to a Non U.S. Person pursuant to Regulation S and (2) such Non U.S. Person wishes to hold its interest in the Note through a beneficial interest in the Unrestricted Global Security, (x) upon receipt by the Registrar, as Transfer Agent, of:

(i) instructions from the Holder of the Restricted Global Security directing the Custodian and Registrar to credit or cause to be credited a beneficial interest in the Unrestricted Global Security equal to the principal amount of the beneficial interest in the Restricted Global Security to be transferred, and

(ii) a certificate from the transferor as to compliance with Regulation S in form and substance required by the Indenture, and (y) subject to the rules and procedures of DTC and the common depositary for Euroclear and Clearstream, the Registrar, as Transfer Agent, shall instruct DTC to increase the Unrestricted Global Security and decrease the Restricted Global Security by such amount in accordance with the foregoing, and the Registrar, as Transfer Agent, shall instruct the common

depositary for Euroclear and Clearstream, as the case may be, concurrently with such reduction, to increase the principal amount of the Unrestricted Global Security of the same Series by the aggregate principal amount of the beneficial interest in the Restricted Global Security to be so exchanged or transferred, and to credit or cause to be credited to the account of the person specified in such instructions a beneficial interest in such Unrestricted Global Security equal to the reduction in the principal amount of such Restricted Global Security.

(b) Unrestricted Global Security

Unless otherwise specified in the applicable Pricing Supplement, if the owner of an interest in a Unrestricted Global Security wishes to transfer such interest (or any portion thereof) to a QIB pursuant to Rule 144A prior to the expiration of the Distribution Compliance Period therefor, (x) upon receipt by the Registrar, as Transfer Agent, of:

(i) instructions from the Holder of the Unrestricted Global Security directing the Custodian and Registrar to credit or cause to be credited a beneficial interest in the Restricted Global Security equal to the principal amount of the beneficial interest in the Unrestricted Global Security to be transferred, and

(ii) a certificate from the transferor as to compliance with Rule 144A in form and substance required by the Indenture,

and (y) in accordance with the rules and procedures of DTC, the common depositary for Euroclear and Clearstream, the Registrar, as Transfer Agent, shall instruct DTC to increase the Restricted Global Security and decrease the Unrestricted Global Security by such amount in accordance with the foregoing and the Registrar, as Transfer Agent, shall instruct the common depositary for Euroclear and Clearstream, or the custodian for DTC, as applicable, to reduce the principal amount of the Unrestricted Global Security by the aggregate principal amount of the beneficial interest in such Unrestricted Global Security or to be exchanged or transferred, and the Registrar, as Transfer Agent, shall instruct DTC, concurrently with such reduction, to increase the principal amount of such Restricted Global Security by the aggregate principal amount of the beneficial interest in such Unrestricted Global Security to be so exchanged or transferred, and to credit or cause to be credited to the account of the person specified in such instructions a beneficial interest in the Restricted Global Security equal to the reduction in the principal amount of such Unrestricted Global Security.

(c) Other Transfers or Exchanges

Any transfer of Restricted Global Securities not described above (other than a transfer of a beneficial interest in a Global Security that does not involve an exchange of such interest for a Certificated Security or a beneficial interest in another Global Security, which must be effected in accordance with applicable law and the rules and procedures of DTC, the common depositary for Euroclear and Clearstream, but is not subject to any procedure required by the Indenture) shall be made only upon receipt by the Registrar of such opinions of counsel, certificates and/or other information reasonably required by and satisfactory to it in order to ensure compliance with the Securities Act or in accordance with the above. Certificated Securities will not be exchangeable for Bearer Notes.

21. Defeasance

The Indenture provides that the Company will be deemed to have paid and will be discharged from any and all its obligations in respect of all outstanding Notes of any Series on the 183rd day after the deposit referred to below and payments of all amounts due to the Trustee, and the provisions of the Indenture will no longer be in effect with respect to the Notes (except for, among other matters, certain obligations to register the transfer or exchange of the Notes, to replace stolen, lost or mutilated Notes, to maintain paying agencies and to hold monies for payment in trust and to pay Additional Amounts) if, among other things:

(a) the Company has irrevocably deposited with the Trustee (or other qualifying trustee), as trust funds, in trust solely for the benefit of the Holders, cash in U.S. legal tender or U.S. Government Obligations, or a combination thereof, in such amounts as is sufficient (without consideration of any reinvestment of interest), in the opinion of an internationally recognized firm of independent public accountants selected by the Company, to pay the principal of and interest on the Notes on the scheduled due dates or on the applicable redemption date, as the case may be, provided that the Trustee shall have received an irrevocable written order from the Company instructing the Trustee to apply such U.S. legal tender or the proceeds of such U.S. Government Obligations to said payments with respect to such Notes;

(b) the Company has delivered to the Trustee an Opinion of Counsel in the United States of recognized standing acceptable to the Trustee, confirming that (A) the Company has received from, or there has been published by, the Internal Revenue Service a ruling or (B) since the date of the Indenture, there has been a change in the applicable U.S. federal income tax law, in either case to the effect that, and based thereon such Opinion of Counsel shall confirm that, the beneficial owners of Notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(c) the Company has delivered to the Trustee an Opinion of Counsel in the United States of recognized standing acceptable to the Trustee, to the effect that the creation of the defeasance trust does not violate the U.S. Investment Company Act of 1940, as amended, and after the passage of 183 days following the deposit, the trust fund will not be subject to the effect of Section 547 of the United States Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law;

(d) no Default or Event of Default shall have occurred and be continuing on the date of such deposit or during the period ending on the 183rd day after the date of such deposit (other than a Default or Event of Default resulting solely from the borrowing of funds to be applied to such deposit);

(e) such defeasance shall not result in a breach or violation of or constitute a default under the Indenture or any other material agreement or instrument to which the Company or any of its Material Subsidiaries is a party or by which the Company or any of its Material Subsidiaries is bound (other than any such Default or default resulting solely from the borrowing of funds to be applied to such deposit); and

(f) the Company has delivered to the Trustee an Officers' Certificate stating that the deposit was not made by the Company with the intent of preferring the Holders over any other creditors of the Company or with the intent of defeating, hindering, delaying or defrauding any other creditors of the Company or others.

FORMS OF THE NOTES

The Notes of each Series will be in bearer or registered form.

Unless otherwise provided with respect to a particular Series, Notes of each Series sold outside the United States in reliance on Regulation S will be represented by interests in a Temporary Global Note (as defined below), Permanent Global Note (as defined below) or by a global note in registered form, without interest coupons (an "Unrestricted Global Security"), which may be deposited with a common depositary for, and registered in the name of a nominee of, Euroclear and Clearstream. With respect to all offers or sales by a Dealer of an unsold allotment or subscription, beneficial interests in a Temporary Global Note or Bearer Notes issued in definitive form ("Definitive Bearer Note") may not be offered or sold to, or for the account or benefit of, a U.S. person (unless pursuant to the Securities Act or an exemption therefrom) and may be held only through Euroclear and Clearstream, as the case may be. Temporary Global Notes, Permanent Global Notes and Unrestricted Global Securities will be exchangeable for Bearer Definitive Notes or Certificated Securities, as applicable, only in limited circumstances as more fully described in Global Clearance and Settlement Systems. Notes issued in bearer form are subject to U.S. tax law requirements and may not be offered, sold or delivered within the United States or its possessions or to United States persons (as defined in the Internal Revenue Code and the U.S. Treasury regulations thereunder).

Notes of each Series to be issued in registered form ("Registered Notes") may only be offered and sold in the United States in private transactions: (i) to QIBs or (ii) to Institutional Accredited Investors who agree to purchase the Notes for their own account and not with a view to the distribution thereof. Registered Notes of each Series sold in private transactions to QIBs pursuant to Rule 144A will, unless specified in the applicable Pricing Supplement, be represented by a restricted global note in registered form, without coupons (a "Restricted Global Security") deposited with a custodian for, and registered in the name of a nominee of, DTC.

Registered Notes of each Series sold to Institutional Accredited Investors will be in definitive form, registered in the name of the holder thereof (such Notes are defined as "4(2) Notes" in the Indenture). Notes in fully-registered certificated form evidencing all or part of a Series of Notes (each a "Certificated Security") will, at the request of the holder (except to the extent otherwise indicated in the applicable Pricing Supplement), be issued in exchange for interests in an Unrestricted Global Security or a Restricted Global Security (each a "Registered Global Security") upon compliance with the procedures for exchange as described in the Indenture.

Notes of each Series to be issued in bearer form ("Bearer Notes") will be initially represented by either a temporary global Note (a "Temporary Global Note") or a permanent global Note (a "Permanent Global Note" and together with a Temporary Global Note, a "Bearer Global Note") that will be deposited on the issue date thereof with a common depositary on behalf of Euroclear and Clearstream or any other agreed clearance system compatible with Euroclear and Clearstream.

The relevant Pricing Supplement for any Bearer Notes will specify whether United States Treasury Regulation §1.163-5(c)(2)(i)(C) (or any successor rules that are applicable for purposes of Section 4701 of the Internal Revenue Code (the "C Rules") or United States Treasury Regulation §1.163-5(c)(2)(i)(D) (or any successor rules that are applicable for purposes of Section 4701 of the Internal Revenue Code (the "D Rules") are applicable in relation to the Notes or, if the Notes do not have a maturity of more than 365 days (including unilateral rights to rollover or extend), that neither the C Rules nor the D Rules are applicable.

Each Bearer Note, Receipt, Coupon and Talon will bear the following legend: "Any United States person (as defined in the Internal Revenue Code of the United States) who holds this obligation will be subject to limitations under the United States income tax laws, including the limitations provided in Sections 165(j) and 1287(a) of the Internal Revenue Code."

Bearer Notes will be assigned a Common Code and relevant ISIN (as applicable). Registered Notes will be assigned (as applicable) a Common Code, ISIN and CUSIP number. If a further Series is issued in the case of a Temporary Global Note, the Trustee shall arrange that the Notes of such Series shall be assigned (as applicable) a CUSIP number, Common Code and a relevant ISIN that are different from the CUSIP number, Common Code and relevant ISIN, as the case may be, assigned to Notes of any other Series until such time as is required by applicable law. In the case of Bearer Notes to which the D Rules apply, a Temporary Global Note that is exchangeable for an interest in a Permanent Global Note or Definitive Notes must have a different Common Code, ISIN or other identifying number from the identifying number assigned to Notes of any other Series until the exchange of interests in the Temporary Global Note for interests in the Permanent Global Note or Definitive Notes upon certification of non-U.S. beneficial ownership. Additional Registered Notes must be issued with a different Common Code, ISIN, CUSIP or other identifying number from the identifying numbers assigned to Notes of any other Series unless the additional Registered Notes are fungible with such outstanding Series of Notes for U.S. federal income tax purposes. At the end of such period, the CUSIP number, Common Code and relevant ISIN, as the case may be, thereafter applicable to the Notes of the relevant Series will be notified by the Trustee to the Relevant Dealers.

Each Temporary Global Note will be exchangeable, free of charge to the Noteholder, on or after its Exchange Date:

(a) if the relevant Pricing Supplement indicates that such Temporary Global Note is issued in compliance with the C Rules or in a transaction to which neither the C Rules nor D Rules are applicable (as to which, see "Plan of Distribution"), in whole, but not in part, for the Definitive Bearer Notes described below; and

(b) if the relevant Pricing Supplement indicates that such Temporary Global Note is issued in compliance with the D Rules, in whole or in part upon certification as to non-U.S. beneficial ownership in the form set out in the Indenture for interests in a Permanent Global Note or, if so provided in the relevant Pricing Supplement, for Definitive Bearer Notes.

Each Permanent Global Note will be exchangeable, free of charge to the Noteholder, on or after its Exchange Date in whole but not in part for Definitive Bearer Notes:

(a) if an Event of Default has occurred in respect of any Note of the relevant Series; or

(b) if the Permanent Global Note is held on behalf of Euroclear or Clearstream, Luxembourg or an Alternative Clearing System and any such clearing system is closed for business for a continuous period of 14 days (other than by reason of holidays, statutory or otherwise) or announces an intention permanently to cease business or in fact does so.

In the event that a Bearer Global Note is exchanged for Definitive Bearer Notes, such Definitive Bearer Notes shall be issued in Specified Denomination(s) only. A holder of Notes with a principal amount of less than the minimum Specified Denomination will not receive a definitive Note in respect of such holding and would need to purchase a principal amount of Notes such that it holds an amount equal to one or more Specified Denominations.

"Exchange Date" means the day which is 40 days after the Issue Date.

All Notes will be issued pursuant to the Indenture.

No beneficial owner of an interest in a Registered Global Security will be able to exchange or transfer that interest, except in accordance with the applicable procedures of DTC, Euroclear and/or Clearstream, in each case, to the extent applicable.

So long as any Notes are listed on the SGX-ST and the rules of the SGX-ST so require, the Company shall appoint and maintain a paying agent in Singapore, where such Notes may be presented or surrendered for payment or redemption, in the event that the Global Security representing such Notes is exchanged for Definitive Notes. In addition, an announcement of such exchange will be made through the SGX-ST. Such announcement will include all material information with respect to the delivery of the Definitive Notes, including details of the paying agent in Singapore.

FORM OF PRICING SUPPLEMENT

[**PRIIPS REGULATION / PROHIBITION OF SALES TO EEA RETAIL INVESTORS** — The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the European Economic Area ("EEA"). For these purposes, a retail investor in the EEA means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of MiFID II; (ii) a customer within the meaning of Directive 2002/92/EC (as amended, the "Insurance Mediation Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; and (iii) not a qualified investor as defined in the Prospectus Directive (as defined herein). Consequently, no key information document required by Regulation (EU) No 1286/2014 (the "PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.]*

[**MIFID II PRODUCT GOVERNANCE/ PROFESSIONAL INVESTORS AND ELIGIBLE COUNTERPARTIES ONLY TARGET MARKET** — Solely for the purposes of each manufacturer's product approval process, the target market assessment in respect of the Notes has led to the conclusion that: (i) the target market for the Notes is eligible counterparties and professional clients only, each as defined in [Directive 2014/65/EU (as amended "MiFID II")][MiFID II] and (ii) all channels for distribution of the Notes to eligible counterparties and professional clients are appropriate. Any person subsequently offering, selling or recommending the Notes (a "distributor") should take into consideration the manufacturers' target market assessment; however, a distributor subject to MiFID II is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the manufacturers' target market assessment and determining appropriate distribution channels.]†

Pricing Supplement dated [●]
PT PERTAMINA (PERSERO)

Issue of [Aggregate Nominal Amount of Series] [Title of Notes]
(the "Notes")
under its U.S.$10,000,000,000 Global Medium Term Note Program

This document constitutes the Pricing Supplement relating to the issue of Notes described herein.

Terms used herein shall be deemed to be defined as such for the purposes of the Conditions set forth in the Offering Memorandum dated [●], 2019 [and the supplemental [Offering Memorandum] dated [●]]. This Pricing Supplement contains the final terms of the Notes and must be read in conjunction with such Offering Memorandum [as so supplemented].

[*The following alternative language applies if the first issue of a Series which is being increased was issued under Offering Memorandum with an earlier date.*

Terms used herein shall be deemed to be defined as such for the purposes of the Conditions (the "**Conditions**") set forth in the Offering Memorandum dated [original date]. This Pricing Supplement contains the final terms of the Notes and must be read in conjunction with the Offering Memorandum dated [current date] [and the supplemental Offering Memorandum dated [●]], save in respect of the Conditions which are extracted from the Offering Memorandum dated [original date] and are attached hereto.]

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* To be inserted unless the Pricing Supplement specifies "Prohibition of Sales to EEA Retail Investors" as "Not Applicable."

† To be inserted if applicable.

[Notification under Section 309B(1)(c) of the Securities and Futures Act (Chapter 289) of Singapore — [*To insert notice if the classification of the Notes is not "prescribed capital markets products" pursuant to Section 309B of the SFA or Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).*]‡

[*Include whichever of the following apply or specify as "Not Applicable" (N/A). Note that the numbering should remain as set out below, even if "Not Applicable" is indicated for individual paragraphs or sub-paragraphs. Italics denote directions for completing the Pricing Supplement.*]

1.	Issuer:	PT Pertamina (Persero)
2.	[(i)] Series Number:	[●]
	[(ii) Tranche]:	[●]
3.	Specified Currency or Currencies:	[●]
4.	Aggregate Nominal Amount:	[●]
5.	[(i)] Issue Price:	[●]% of the Aggregate Nominal Amount [plus accrued interest from [*insert date*](*in the case of fungible issues only, if applicable*)]
	[(ii) Net proceeds:	[●] (Required only for listed issues)]
6.	(i) Specified Denominations:	[●]
	(ii) Calculation Amount:	[●]
7.	(i) Issue Date:	[*Specify*/Issue date/Not Applicable]
	(ii) Interest Commencement Date:	
8.	Maturity Date:	[*specify date or (for Floating Rate Notes) Interest Payment Date falling in or nearest to the relevant month and year*]
9.	(i) Interest Basis:	[[●]% Fixed Rate] [[*specify reference rate*] +1-[●]% Floating Rate] [Zero Coupon] [Other (*specify*)] (further particulars specified below)
	(ii) Default Rate:	[[●] (*specify* /None]

‡ Relevant Dealer(s) to consider whether such Relevant Dealer(s) have received the necessary product classification from the Issuer prior to the launch of the offer, pursuant to Section 309B of the SFA.

10.	Redemption/Payment Basis:	[Redemption at par] [Partly Paid] [Installment] [Other (*specify*)]
11.	Change of Interest or Redemption/ Payment Basis:	[*Specify details of any provision for convertibility of Notes into another interest or redemption/ payment basis*]
12.	Put/Call Options:	[Investor Put] [Issuer Call] [(further particulars specified below)]
13.	Status of the Notes:	Senior
14.	Listing:	[[●] (specify)/None]
15.	Place of Payment:	[*Specify*]
16.	Method of distribution:	[Syndicated/Non-syndicated]

PROVISIONS RELATING TO INTEREST (IF ANY) PAYABLE

17.	**Fixed Rate Note Provisions**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
	(i) Rate[(s)] of Interest:	[●]% per annum [payable [annually/semi- annually/ quarterly/monthly] in arrears]
	(ii) Interest Payment Date(s):	in each year [adjusted in accordance with [*specify Business Day Convention and any applicable Business Center(s) for the definition of "Business Day*"]/not adjusted]
	(iii) Fixed Coupon Amount[(s)]:	[●] per Calculation Amount
	(iv) Broken Amount(s):	[●] per Calculation Amount, payable on the Interest Payment Date falling [in/on]
	(v) Day Count Fraction:	[30/360 / Actual/Actual (ICMA/ISDA) / other]
	(vi) [Determination Dates:	[●] in each year (*insert regular interest payment dates, ignoring issue date or maturity date in the case of a long or short first or last coupon. N.B. only relevant where Day Count Fraction is Actual/ Actual (ICMA))*]
	(vii) Other terms relating to the method of calculating interest for Fixed Rate Notes:	[Not Applicable/*give details*]

18.	**Floating Rate Note Provisions**	[Applicable/Not Applicable] *(If not applicable, delete the remaining subparagraphs of this paragraph.*
(i)	Interest Period(s):	[●]
(ii)	Specified Interest Payment Dates:	[●]
(iii)	Interest Period Date:	[●] (*Not applicable unless different from Interest Payment Date*
(iv)	Business Day Convention:	[Floating Rate Convention/Following Business Day Convention/ Modified Following Business Day Convention/ Preceding Business Day Convention/ other (*give details*)]
(v)	Business (Center(s):	[●]
(vi)	Manner in which the Rate(s) of Interest is/ are to be determined:	[Screen Rate Determination/ISDA Determination/ other (*give details*)]
(vii)	Party responsible for calculating the Rate(s) of Interest and Interest Amount(s) (if not the [Agent]):	[●]
(viii)	Screen Rate Determination:	
	— Reference Rate:	[●]
	— Interest Determination Date(s):	[●]
	— Relevant Screen Page:	[●]
(ix)	ISDA Determination:	
	— Floating Rate Option:	[●]
	— Designated Maturity:	[●]
	— Reset Date:	[●]
(x)	Margin(s):	[+/-][●]% per annum
(xi)	Minimum Rate of Interest:	[●]% per annum
(xii)	Maximum Rate of Interest:	[●]% per annum

(xiii)	Day Count Fraction:	[●]
(xiv)	Fall back provisions, rounding provisions, denominator and any other terms relating to the method of calculating interest on Floating Rate Notes, if different from those set out in the Conditions:	[●]
19.	**Zero Coupon Note Provisions**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
(i)	Amortization Yield:	[●]% per annum
(ii)	Any other formula/basis of determining amount payable:	[●]
20.	**Index-Linked Interest Note Provisions**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
(i)	Index/Formula: [*give or annex details*]	
(ii)	Party responsible for calculating the Rate(s) of Interest and/or Interest Amount(s) (if not the [Agent]):	[●]
(iii)	Provisions for determining Rate of Interest and/or Interest Amount where calculation by reference to Index and/or Formula is impossible or impracticable or otherwise disrupted:	[●]
(iv)	Interest Periods:	[●]
(v)	Specified Interest Payment Dates:	[●]
(vi)	Business Day Convention:	[Floating Rate Convention/Following Business Day Convention/Modified Following Business Day Convention/Preceding Business Day Convention/ other (*give details)*]
(vii)	Business Center(s):	[●]
(viii)	Minimum Rate of Interest:	[●]% per annum
(ix)	Maximum Rate of Interest:	[●]% per annum
(x)	Day Count Fraction:	[●]

21.	**Dual Currency Note Provisions**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
	(i) Rate of Exchange/method of calculating Rate of Exchange:	[*give details*]
	(ii) Party, if any, responsible for calculating the Rate(s) of Interest and Interest Amount(s) (if not the [Agent]):	[●]
	(iii) Provisions applicable where calculation by reference to Rate of Exchange impossible or impracticable:	[●]
	(iv) Person at whose option Specified Currency(ies) is/are payable:	[●]
22.	**Default Rate**	[●]% per annum

PROVISIONS RELATING TO REDEMPTION

23.	**Call Option**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
	(i) Optional Redemption Date(s):	[●]
	(ii) Optional Redemption Amount(s) of each Note and specified denomination method, if any, of calculation of such amount(s):	[●] per Calculation Amount
	(iii) If redeemable in part:	[●]
	(a) Minimum Redemption Amount:	[●] per Calculation Amount
	(b) Maximum Redemption Amount:	[●] per Calculation Amount
	(iv) Notice period:	[●]
24.	**Put Option**	[Applicable/Not Applicable] (*If not applicable, delete the remaining subparagraphs of this paragraph*)
	(i) Optional Redemption Date(s):	[●]
	(ii) Optional Redemption Amount(s) of each Note and method, if any, of calculation of such amount(s):	[●] per Calculation Amount
	(iii) Notice period:	[●]

25.	**Final Redemption Amount of each Note**	[●] per Calculation Amount
26.	**Early Redemption Amount**	
	Early Redemption Amount(s) per Calculation Amount payable on redemption for taxation reasons or on event of default and/ or the method of calculating the same (if required or if different from that set out in the Conditions):	[●]

GENERAL PROVISIONS APPLICABLE TO THE NOTES

27.	(i) Form of Notes:	[Bearer Notes: [Temporary Global Note exchangeable for a Permanent Global Note which is exchangeable for Definitive Notes in the limited circumstances specified in the Permanent Global Note] [Temporary Global Note exchangeable for Definitive Notes [●] on days' notice] [Permanent Global Note exchangeable for Definitive Notes in the limited circumstances specified in the Permanent Global Note][§] (*N.B. The exchange upon notice/at any time options should not be expressed to be applicable if the Specified Denomination of the Notes in paragraph 6 includes language substantially to the following effect: "EUR100,000 and integral multiples of EUR1,000 in excess thereof up to and including EUR199,000." In addition, the "limited circumstances specified in the Permanent Global Note" option may have to be amended to permit such Specified Denomination construction.* *Furthermore, such Specified Denomination construction is not permitted in relation to any issue of Notes which is to be represented on issue by a Temporary Global Note exchangeable for Definitive Notes.*)] [Registered Notes]
	(ii) Applicable TEFRA exemption:	[C Rules/ D Rules/ Not Applicable][**]
28.	Talons for future Coupons or Receipts to be attached to Definitive Bearer Notes (and dates on which such Talons mature):	[Yes/No. If yes, give details]

[§] Cannot be used if D Rules apply.

[**] Bearer Notes with a maturity of 365 days or more (including unilateral right to rollover or extend) must be issued using either C Rules or D Rules.

29.	Financial Center(s) or other special provisions relating to Payment Dates:	[*Note that this paragraph relates to the Payment Date and Place of Payment, and not interest period end dates, to which sub paragraphs 16 (ii), 17(iv) and 19(vii) relate*]
30.	Details relating to Partly Paid Notes: amount of each [Not Applicable/*give details*] payment comprising the Issue Price and date on which each payment is to be made and consequences (if any) of failure to pay, including any right of the Issuer to forfeit the Notes and interest due on late payment:	[Not Applicable/*give details*]
31.	Details relating to Installment Notes: amount of each installment, date on which each payment is to be made:	[Not Applicable/*give details*]
32.	Redenomination, Renominalization and Reconventioning:	[Not Applicable/The provisions [in Condition 2C] [annexed to this Pricing Supplement] apply]
33.	Consolidation provisions:	[Not Applicable/The provisions [In Condition] [●] [annexed to this Pricing Supplement] apply]
34.	Use of Proceeds:	[Not Applicable/*give details*]
35.	Other terms or special conditions:	[Not Applicable/*give details*]

DISTRIBUTION

36.	(i)	If syndicated, names of Managers:	[Not Applicable/*give details*]
	(ii)	Stabilizing Manager (if any):	[Not Applicable/*give details*]
37.		If non-syndicated, name of Dealer:	[Not Applicable/*give details*]
38.		Additional selling restrictions:	[Not Applicable/*give details*]
39.		Interests of [Managers][Dealers] involved in the issue / offer:	[*Give details*]

OPERATIONAL INFORMATION

40.	ISIN Code:	[●]
41.	CUSIP:	[●]
42.	Common Code:	[●]

43.	Any clearing system(s) other than Euroclear Bank S.A./N.V. and Clearstream Banking societe anonyme and the relevant identification number(s)	[Not Applicable/*give name(s) and number(s)*]
44.	Delivery:	Delivery [against/free of] payment
45.	Additional Paying Agent(s) (if any):	[●]

[PURPOSE OF PRICING SUPPLEMENT

This Pricing Supplement comprises the final terms required for issue and admission to trading on the Singapore Exchange Securities Trading Limited of the Notes described herein pursuant to the U.S.$10,000,000,000 Global Medium Term Note Program of the Issuer.]

RESPONSIBILITY

The Issuer accepts responsibility for the information contained in this Pricing Supplement.

Signed on behalf of PT Pertamina (Persero)

By: _____

Duly authorized

GLOBAL CLEARANCE AND SETTLEMENT SYSTEMS

The information set out below is subject to any change in or reinterpretation of the rules, regulations and procedures of DTC, Euroclear and Clearstream (together, the "Clearing Systems") currently in effect. Investors wishing to use the facilities of any of the Clearing Systems are advised to confirm the continued applicability of the rules, regulations and procedures of the relevant Clearing System. Our Company, any Arranger, Dealer, Trustee, Agent and party to the Indenture will not have any responsibility or liability for any aspect of the records relating to, or payments made on account of, beneficial ownership interests in the Notes held through the facilities of any Clearing System or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

The relevant Pricing Supplement will specify the Clearing System(s) applicable for each series.

DTC

DTC is a limited purpose trust company organized under the laws of the State of New York, a member of the United States Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered pursuant to Section 17A of the United States Securities Exchange Act of 1934, as amended. DTC was created to hold securities for its participants and to facilitate the clearance and settlement of securities transactions among participants in such securities through electronic book-entry changes in accounts of the participants, thereby eliminating the need for physical movement of security certificates. Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is owned by a number of its participants and by the New York Stock Exchange, Inc., the American Stock Exchange, Inc. and the National Association of Securities Dealers, Inc. Indirect access to DTC is available to others, such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a DTC participant either directly or indirectly.

DTC will take any action permitted to be taken by the holder of a beneficial interest in a Global Security (including, without limitation, the presentation of a Global Security for exchange) only at the direction of one or more participants to whose account with DTC interests in such Registered Global Security are credited and only in respect of such portion of the aggregate principal amount of Notes in respect of which such participant or participants has or have given such direction. If an Event of Default under the Notes occurs, DTC will exchange the Global Security for Certificated Securities bearing the appropriate legend, which it will distribute to the relevant participants. DTC makes payments only in U.S. dollars.

Euroclear and Clearstream

Each of Euroclear and Clearstream holds securities for their account holders and facilitates the clearance and settlement of securities transactions by electronic book-entry transfer between their respective account holders, thereby eliminating the need for physical movements of certificates and any risks from lack of simultaneous transfers of securities.

Euroclear and Clearstream each provides various services including safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Euroclear and Clearstream each also deals with domestic securities markets in several countries through established depository and custodial relationships. Euroclear and Clearstream have established an electronic bridge between their two systems which enables their respective account holders to settle trades with each other.

Account holders in Euroclear and Clearstream are financial institutions throughout the world, including underwriters, securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. Indirect access to both Euroclear and Clearstream is available to other institutions that clear through or maintain a custodial relationship with an account holder of either system.

An account holder's contractual relations with either Euroclear or Clearstream are governed by the respective rules and operating procedures of Euroclear or Clearstream and any applicable laws.

Both Euroclear and Clearstream act under those rules and operating procedures only on behalf of their respective account holders, and have no record of or relationship with persons holding through their respective holders.

Book-Entry Ownership of Global Certificates

Registered Notes

The Company will make applications to Euroclear and/or Clearstream for acceptance in their respective book-entry systems in respect of each Tranche of Notes to be represented by an Unrestricted Global Security. Each Unrestricted Global Security will have an ISIN or Common Code, and will be subject to restrictions on transfer contained in a legend appearing on the front of such Note, as set out under "Transfer Restrictions."

The Company will make applications to DTC for acceptance in its book-entry settlement system of the Notes represented by a Restricted Global Security. Each Restricted Global Security will have a CUSIP number. Each Restricted Global Security will be subject to restrictions on transfer contained in a legend appearing on the front of such Note, as set out under "Transfer Restrictions."

The custodian with whom the Global Securities are deposited (the "Custodian") and DTC will electronically record the principal amount of the Notes represented by the Restricted Global Security held within the DTC system. Investors may hold their interests in the Unrestricted Global Security only through Clearstream or Euroclear. Investors may hold such interests in Restricted Global Securities directly through DTC if they are participants in such system, or indirectly through organizations that are participants in such system.

Payments of principal and interest in respect of Restricted Global Securities registered in the name of DTC's nominee, will be to or to the order of its nominee as the registered holder of such Restricted Global Security. The Company expects that the nominee will, upon receipt of any such payment, immediately credit DTC participants' accounts with any such payments denominated in U.S. dollars in amounts proportionate to their respective beneficial interests in the principal amount of the relevant Restricted Global Security as shown on the records of DTC or its nominee. In the case of any such payments which are denominated otherwise than in U.S. dollars payment of such amounts will be made to the Paying Agent on behalf of the nominee who will make payment of all or part of the amount to the beneficial holders of interests in such Restricted Global Securities directly, in the currency in which such payment was made and/or cause all or part of such payment to be converted into U.S. dollars and credited to the relevant participant's DTC account as aforesaid, in accordance with instructions received from DTC. The Company also expects that payments by DTC participants to owners of beneficial interests in such Restricted Global Securities held through such DTC participants will be governed by standing instructions and customary practices, as is now the case with securities held for the accounts of customers registered in the names of nominees for such customers. Such payments will be the responsibility of such DTC participants. None of the Company, the Trustee nor

any agent will have any responsibility or liability for any aspect of the records relating to or payments made on account of ownership interests in the Restricted Global Securities or for maintaining, supervising or reviewing any records relating to such ownership interests.

Bearer Notes

Bearer Notes held outside the United States may be held in book-entry form through Clearstream or Euroclear. In respect of Bearer Notes, as may be specified in the applicable Pricing Supplement, a Temporary Global Note and/or a Permanent Global Note in bearer form without coupons will be deposited with a common depositary for Euroclear and Clearstream. Transfers of interests in a Temporary Global Note or a Permanent Global Note will be made in accordance with customary Euromarket practice.

Individual Certificated Securities

Registration of title to Notes in a name other than its nominee or a depositary for Euroclear and Clearstream or DTC will not be permitted unless (i) in the case of Restricted Securities, an event of default with respect to such Series has occurred and is continuing or DTC notifies us that it is no longer willing or able to discharge properly its responsibilities as depositary with respect to the Restricted Global Securities, or ceases to be a "clearing agency" registered under the Exchange Act, or is at any time no longer eligible to act as such and the Company is unable to locate a qualified successor within 90 days of receiving notice of such ineligibility on the part of DTC, (ii) in the case of Unrestricted Global Securities deposited with a common depositary for Euroclear or Clearstream, Euroclear or Clearstream is closed for business for a continuous period of 14 days (other than by reason of holidays, statutory or otherwise) or announces an intention permanently to cease business or does in fact do so, (iii) the Trustee has instituted or has been directed to institute any judicial proceeding in a court to enforce the rights of Holders of the Notes under the Notes and the Trustee has been advised by counsel that in connection with such proceeding it is necessary or appropriate for the Trustee to obtain possession of the Notes. In such circumstances, the Company will cause sufficient individual Certificated Securities to be executed and delivered to the Registrar for completion, authentication and dispatch to the relevant Holder(s) of the Notes.

A person having an interest in a Global Security must provide the Registrar with:

(a) written order containing instructions and such other information as the Company and the Registrar may require to complete, execute and deliver such individual Certificated Securities; and

(b) in the case of a Restricted Global Security only, a fully completed, signed certification substantially to the effect that the exchanging holder is not transferring its interest at the time of such exchange, or in the case of a simultaneous resale pursuant to Rule 144A, a certification that the transfer is being made in compliance with the provisions of Rule 144A. Certificated Securities issued pursuant to this paragraph (b) shall bear the legends applicable to transfers pursuant to Rule 144A.

Transfers of Notes represented by Global Securities

Transfers of interests in Global Securities within DTC, Euroclear and Clearstream will be in accordance with the usual rules and operating procedures of the relevant system. The laws in some states in the United States require that certain persons take physical delivery of securities in definitive form. Consequently, the ability to transfer a beneficial interest in a Global Securities to such persons

may require that such interests be exchanged for Notes in definitive form. Because DTC can only act on behalf of participants in DTC, who in turn act on behalf of indirect participants, the ability of a person having an interest in a Global Security to pledge such interest to persons or entities that do not participate in the DTC system, or otherwise take actions in respect of such interest may require that such interests be exchanged for Certificated Securities. The ability of the holder of a beneficial interest in any Note represented by the Global Securities to resell, pledge or otherwise transfer such interest may also be impaired if the proposed transferee of such interest is not eligible to hold the same through a participant or indirect participant in DTC.

Beneficial interests in an Unrestricted Global Security may be held through Clearstream or Euroclear. Clearstream and Euroclear will operate with respect to the Notes in accordance with customary Euromarket practice.

Secondary Trading, Same-Day Settlement and Payment

All payments made by the Company with respect to Notes registered in the name of Cede & Co., as nominee for DTC, will be passed through to DTC in same-day funds. In relation to secondary market trading, since the purchaser determines the place of delivery, it is important to establish at the time of the trade where both the purchaser's and seller's accounts are located to ensure that settlement can be made on the desired value date.

Trading Within Same Clearing System

The following describes the transfer mechanisms between DTC, Euroclear and Clearstream. Holders should note that transfers of beneficial interests in the Restricted Global Security, or the Unrestricted Global Security is subject to limitations as set forth in "Transfer Restrictions."

Trading within DTC. If neither the seller, nor the purchaser of Notes represented by any Global Security holds or will receive (as the case may be) such Notes through a participant in DTC acting on behalf of Euroclear or Clearstream, the trade will settle in same-day funds and in accordance with DTC rules, regulations and procedures.

Trading within Euroclear or Clearstream. Transfers between account holders in Euroclear and Clearstream will be effected in the ordinary way in accordance with their respective rules and operating procedures.

Trading Between Clearing Systems

Trading between Euroclear or Clearstream seller and DTC purchaser involving only Global Securities. Due to time zone differences in their favor, Euroclear and Clearstream account holders may employ their customary procedures for transactions in which interests in a Global Security are to be transferred by Euroclear or Clearstream (as the case may be) to a participant in DTC. The seller will send instructions to Euroclear or Clearstream through a Euroclear or Clearstream account holder (as the case may be) at least one business day prior to settlement. In these cases, Euroclear or Clearstream will instruct its respective depositary to deliver the interests in the Global Security to the participant's account against payment. Payment will include interest (if any) accrued on such interests in the Note from (and including) the immediately preceding date for the payment of interest to (and excluding) the settlement date. The payment will then be reflected in the account of the Euroclear or Clearstream account holder the following day, and receipt of cash proceeds in the Euroclear or Clearstream account holders' account would be back-valued to the value date (which would be the preceding day when settlement occurred in New York). Should the Euroclear or Clearstream account holder have a line of

credit in its respective Clearing System and elect to be in debit in anticipation of receipt of the sale proceeds in its account, the back-valuation will extinguish any overdraft charges incurred over that one-day period. If settlement is not completed on the intended value date (i.e. the trade fails), receipt of the cash proceeds in the Euroclear or Clearstream account holder's account would be valued instead as of the actual settlement date.

Trading between DTC seller and Euroclear or Clearstream purchaser involving only Global Securities. When interests in a Global Security are to be transferred from the account of a DTC participant to the account of a Euroclear or Clearstream account holder, the purchaser will send instructions to Euroclear or Clearstream through a Euroclear or Clearstream account holder, as the case may be, at least one business day prior to settlement. Euroclear or Clearstream, as the case may be, will instruct its respective depositary to receive such interests against payment. Payment will include interest (if any) accrued on such interest in the Global Security from (and including) the immediately preceding date for the payment of interest to (and excluding) the settlement date. Payment will then be made by the depositary to the participant's account against delivery of the interests in the Note. After settlement has been completed, the interests will be credited to the respective Clearing System, and by the Clearing System, in accordance with its usual procedures, to the Euroclear or Clearstream account holder's account. The securities credit will appear the next day (Central European time) and the cash debit will be back-valued to, and any interest on the Note will accrue from, the value date (which would be the preceding day when settlement occurred in New York). If settlement is not completed on the intended value date (i.e., the trade fails), the Euroclear or Clearstream cash debit will be valued instead as of the actual settlement date.

Day traders that use Euroclear or Clearstream to purchase interests in an Unrestricted Global Security from participants for delivery to Euroclear or Clearstream account holders should note that these trades will automatically fail on the sale side unless affirmative action is taken. At least three techniques should be readily available to eliminate this potential problem:

(a) borrowing through Euroclear or Clearstream for one day (until the purchase side of the day trade is reflected in their Euroclear or Clearstream accounts) in accordance with the Clearing System's customary procedures;

(b) borrowing the interests in the United States from a participant no later than one day prior to settlement, which would give the interests sufficient time to be reflected in their Euroclear or Clearstream account in order to settle the sale side of the trade; or

(c) staggering the value date for the buy and sell sides of the trade so that the value date for the purchase from the participant is at least one day prior to the value date for the sale to the Euroclear or Clearstream account holder.

Euroclear or Clearstream account holders will need to make available to the respective Clearing System the funds necessary to process same-day funds settlement. The most direct means of doing so is to pre-position funds for settlement, either from cash on-hand or existing lines of credit, as such participants would for any settlement occurring within Euroclear or Clearstream. Under this approach, such participants may take on credit exposure to Euroclear or Clearstream until the interests in the Note are credited to their accounts one day later.

Alternatively, if Euroclear or Clearstream has extended a line of credit to a Euroclear or Clearstream account holder, as the case may be, such account holder may elect not to preposition funds and allow that credit line to be drawn upon to finance settlement. Under this procedure, Euroclear or Clearstream account holders purchasing interests in the Note held in DTC would incur overdraft

charges for one day, assuming they cleared the overdraft when the interests in the Note were credited to their accounts. However, any interest on the Note would accrue from the value date. Therefore, in many cases the investment income on the interests in the Note held in DTC earned during that one-day period may substantially reduce or offset the amount of such overdraft charges, although this result will depend on each account holder's particular cost of funds.

Since the settlement takes place during New York business hours, participants can employ their usual procedures for transferring interests in global Notes to the respective depositories of Euroclear or Clearstream for the benefit of Euroclear or Clearstream account holders. The sale proceeds will be available to the DTC seller on the settlement date. Thus, to the participants, a crossmarket transaction will settle no differently from a trade between participants.

Secondary trading in long-term notes and debentures of corporate issuers is generally settled in clearinghouse or next-day funds. In contrast, Notes held through participants or indirect participants will trade in DTC's Same-Day Funds Settlement System until the earliest of maturity or redemption, and secondary market trading activity in such Notes will therefore be required by DTC to settle in immediately available funds. No assurance can be given as to the effect, if any, of settlements in immediately available funds on trading activity in such Notes.

Although DTC, Clearstream and Euroclear have agreed to the foregoing procedures in order to facilitate transfers of beneficial interests in the Global Securities among participants and account holders of DTC, Clearstream and Euroclear, they are under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. None of the Company, the Trustee, any agent, any Arranger or any Dealer will have the responsibility for the performance by DTC, Clearstream or Euroclear or their respective direct or indirect participants or account holders of their respective obligations under the rules and procedures governing their operations.

While a Restricted Global Security is lodged with DTC or its custodian, Notes represented by individual Certificated Securities will not be eligible for clearing or settlement through DTC, Clearstream or Euroclear.

TAXATION

Indonesian Taxation

The following is a summary of the principal Indonesian tax consequences relevant to prospective holders of the Notes based on Indonesian tax laws and their implementing regulations in force as of the date of this Offering Memorandum. The summary does not address any laws other than the tax laws of the Republic of Indonesia. Prospective investors in all jurisdictions are advised to consult their own tax advisors as to other tax consequences of the acquisition, ownership and disposition of the Notes.

General

Resident taxpayers, individual or corporate, are subject to income tax in Indonesia. Generally, an individual is considered to be a non-resident of Indonesia if the individual does not reside in Indonesia and does not intend to stay in Indonesia for more than 183 days within a 12-month period. A company will be considered a non-resident of Indonesia if the company is not established and not domiciled in Indonesia. In determining the residency and tax status of an individual or corporation, consideration will also be given to the provision of any applicable double tax treaty which Indonesia has concluded with other countries. In this section, both non-resident individuals and non-resident corporations will be referred to as "non-resident taxpayers."

The Indonesian Directorate General of Tax ("DGT") issued Regulation PER-43/PJ/ 2011, which clarifies how to determine tax residency. The regulation, which came into force on December 28, 2011, is the sole implementing regulation on tax residency.

Pursuant to Regulation PER-43/PJ/2011, an individual is a resident if: (a) he/she resides in Indonesia; (b) he/she is domiciled in Indonesia for more than 183 days within 12 months; or (c) in a given fiscal year, he/she stays in Indonesia and intends to reside in Indonesia. The intention provided in the latter will be indicated by the individual obtaining of a working visa or limited stay permit card (*KITAS*) or having a contract of employment, business, or activities that are performed in Indonesia for more than 183 days. Leasing a residence or moving his/her family members to Indonesia will also indicates his/her intention to be an Indonesian tax resident. Resident status would commence as of the date he receives or derives earnings exceeding the nontaxable income threshold. An individual is considered residing in Indonesia if he or she has a place of residence for permanent dwelling place or ordinary course of life or a place of habitual abode in Indonesia.

According to Regulation PER-43/PJ/2011, a legal entity is a resident taxpayer if it is an entity established in Indonesia or meets any of the following criteria:

(a) it is domiciled in Indonesia;

(b) its head office is in Indonesia;

(c) its central administration/finance office is in Indonesia;

(d) its controlling head office is in Indonesia;

(e) its management resides or is domiciled in Indonesia; or

(f) management meets in Indonesia to make a strategic decision.

Regulation PER-43/PJ/2011 stipulates that a foreign tax resident is an individual who does not reside in Indonesia and is located in Indonesia no more than 183 days within 12 months, or who is an Indonesian citizen who works abroad for more than 183 days within 12 months. That citizen will be treated as a domestic tax resident if he does not have or is unable to provide an official valid ID proving he is a tax resident abroad.

Regulation PER-43/PJ/2011 also stipulates that an entity that is not established or domiciled in Indonesia but conducts business or activities in Indonesia, whether through a permanent establishment or not, and that receives or derives earnings from Indonesia is a foreign tax resident but will be treated as a domestic corporate tax resident. Having its management domiciled in Indonesia would not cause that entity to have a permanent establishment in Indonesia as long as the management only performs daily functions and does not control the whole operation of the company or make strategic decisions.

Subject to the provisions of any applicable agreement for the avoidance of double taxation ("tax treaty"), non-resident taxpayers, which derive income sourced in Indonesia from, among other things, interest, royalties or dividends from Indonesia, are subject to a final withholding tax on that income at the rate of 20%, so long as the income is not effectively connected with a permanent establishment of such individuals or corporations in Indonesia. If the income is effectively connected with a permanent establishment in Indonesia, such income shall be regarded as income earned by the permanent establishment. Income earned by the permanent establishment is subject to the income tax rate applied to income earned by an Indonesian corporate tax resident, which is 25%, and a branch profit tax of 20% will be imposed on the net profit after income tax. Such branch profit tax may be reduced by an applicable tax treaty and/or waived if certain requirements are met.

Taxation on Interest

The statutory withholding tax rate on interest due by the Issuer to a non-resident taxpayer is 20%. The 20% rate could be reduced under an applicable tax treaty. For example, under the U.S.-Indonesia tax treaty, the rate is generally reduced to 10% where the interest is not effectively connected to a permanent establishment in Indonesia and the recipient is the beneficial owner of the interest. Application of the reduced withholding tax rate under a tax treaty to a non-resident taxpayer who resides in the tax treaty country is subject to satisfying the eligibility and reporting requirements for the relevant tax treaty and domestic tax regulations. See "— Anti-Avoidance Rule on the Tax Treaty and New CoD Requirements."

Repayments of principal of the Notes by the Issuer are not subject to Indonesian tax. However, under Government Regulation No. 16 of 2009, as amended by Government Regulation No. 100 of 2013 ("Tax Regulation No. 16"), any amount due by the Issuer attributable to interest or premium or discount (which in general are also treated as interest) payable on the Notes will be subject to a final withholding tax in Indonesia.

Generally, a final tax rate of 15% would apply to interest paid to a resident taxpayer or permanent establishment (other than an Indonesian bank or foreign bank with a permanent establishment in Indonesia, in which case such entity is exempt from withholding tax). A special tax rate of 5% is available for interest received by a mutual fund until year 2020, provided that the fund is registered at the Indonesia Capital Market and Financial Institution Supervisory Board. From 2021 onward, the tax rate for interest received by a registered mutual fund will be 10%.

Taxation on Sale or Disposition of Notes

Pursuant to Tax Regulation No. 16, gain from disposal of Notes (the difference between the selling price above the acquisition price of the Notes, excluding accrued interest) is considered interest that is subject to a final withholding tax.

Gains from disposal of the Notes derived by a resident taxpayer, whether an individual or a corporation, or by a permanent establishment, is subject to final withholding tax at the rate of 15%.

Non-resident individuals and corporations other than permanent establishments in Indonesia may not be subject to Indonesian tax or withholding tax on any gain derived from the direct sale or disposal of Notes to a non-resident individual or corporation other than a permanent establishment in Indonesia depending on the relevant double-tax treaty.

However, non-resident individuals and corporations other than permanent establishments in Indonesia may be subject to a 20% Indonesian withholding tax on any gain derived from the sale or disposal of Notes to a resident taxpayer or permanent establishment in Indonesia, or where the transaction is conducted through a securities company, dealer or bank in Indonesia, as such gain would be characterized as interest under Indonesian law in these situations. However, if the non-resident investor is a tax resident of a country that has signed a tax treaty with Indonesia, a reduced withholding tax rate applicable to interest income may be available if the gain (or a portion thereof) is considered as interest for purposes of the relevant tax treaty. Further, a full relief from the imposition of such withholding tax may be available if the relevant treaty treats the income as gain that is taxable only by the country in which the investor is resident for tax purposes. Under the U.S. — Indonesia tax treaty, interest is generally taxed at a rate of 10%, and the term "interest" as used in the treaty includes any income that under Indonesian law is assimilated to income from money lent. Under such treaty, capital gains that are not governed by the interest article of the treaty are generally exempt from Indonesian tax (subject to exceptions applicable to permanent establishments and certain individuals). Any tax treaty relief applicable to a nonresident taxpayer who resides in a tax treaty country is also subject to satisfying the eligibility and reporting requirements for the relevant tax treaty and domestic tax regulations. See "— Anti-Avoidance Rule on the Tax Treaty and New CoD Requirements."

Non-resident investors should consult their own tax advisors regarding the application of Indonesian withholding tax on any gain on the sale or disposal of Notes.

Anti-Avoidance Rule on the Tax Treaty and New CoD Requirements

Indonesia has concluded tax treaties with more than 60 countries including Australia, Belgium, Canada, France, Germany, Japan, the Netherlands, Singapore, Sweden, Switzerland, the United Kingdom and the United States of America. The relevant tax treaty may affect the definition of nonresident taxpayers.

Where a tax treaty exists and the eligibility requirements of that treaty are satisfied, a reduced rate of withholding tax may be applicable in the case of interest (or payments in the nature of interest, such as premium), royalty and dividends. This is also subject to there being no misuse of the tax treaties and the non-resident taxpayers meeting the administrative requirements under the Indonesian tax regulations. Some tax treaties also provide an exemption from Indonesian tax on any capital gains of non-resident taxpayers arising from alienation of certain properties in Indonesia.

To obtain the benefit of an applicable tax treaty, the non-resident taxpayer must be the beneficial owner of the income received from Indonesia and comply with the eligibility requirements of the tax treaty and the specific requirements in Indonesia. Please see below the specific requirements to obtain tax treaty benefits in Indonesia.

On November 21, 2018, the DGT issued Regulation No. PER-25/PJ/2018 on Procedures for Applying Double Tax Avoidance Agreements ("DGT-25"). DGT-25 revokes and replaces Regulation No. PER-10/PJ/2017 on Procedures for Applying Double Tax Avoidance Agreements. DGT-25 is effective from January 1, 2019.

Under DGT-10, in order for a non-resident recipient of the payment from Indonesia to be eligible for tax treaty benefit, it must:

(a) not be an Indonesian tax resident;

(b) be an individual or corporate tax resident of a treaty country;

(c) not misuse the tax treaty; and

(d) be the beneficial owner of the income as required in the tax treaty.

The administrative requirements to be fulfilled by the non-resident taxpayer in order to apply the tax treaty are in the new certificate of domicile ("CoD") form, which must be:

(a) in the form prescribed by the DGT;

(b) filled in correctly, completely, and clearly by the non-resident;

(c) signed by the non-resident income recipient or equivalent mark/stamp as normally used in its country;

(d) certified by the competent tax authority of the treaty country of the non-resident or equivalent mark/stamp as normally used in its country;

(e) completed with a statement that there is no misuse of tax treaty;

(f) completed with a statement that the non-resident recipient is a beneficial owner, if required in the tax treaty; and

(g) used for the period set out under the CoD.

DGT-25 stipulates that misuse of a tax treaty may occur in the case that:

(a) a transaction that has no economic substance in the establishment or execution of transaction;

(b) a transaction has a legal form which differs from its economic substance in the establishment or execution of transaction;

(c) business activities are not managed by its own management and the management has no sufficient authority to carry out transactions;

(d) has no sufficient and adequate assets to carry out business activities in the home country, other than the assets that generate income from Indonesia;

(e) has no sufficient qualified employees to conduct its business operations; and

(f) has no active business other than only receiving income in the form of dividend, interest and/or royalty originating from Indonesia.

Further, a misuse of the tax treaty may also occur if there are arrangements in the transaction, either directly or indirectly, which are intended to obtain benefits from the implementation of a double taxation convention, such as (a) reduction of tax; and/or (b) not being subject to taxes in any country or jurisdiction (double-non taxation), which is contrary to the intent and purpose of concluding a double taxation convention.

In addition, if the non-resident taxpayer receives income for which the relevant tax treaty stipulates a beneficial ownership requirement (for example interest, royalty and dividend income), the non-resident must satisfy the following beneficial ownership test:

(a) if it is an individual, it does not act as an agent or a nominee; or

(b) if it is an entity, it does not act as an agent, a nominee or a conduit company and:

  (i) it has controlling or disposal rights over the fund, assets or the rights that generate the income from Indonesia;

  (ii) no more than 50% of its total income (non-consolidated) is used to satisfy claims by another party in the form of interest, royalty, or other fees (excluding reasonable remuneration to employees, other expenses normally incurred in running the business, or dividend distributions to shareholders);

  (iii) it bears the risk on its own assets, capital or liabilities; and

  (iv) it has no written or unwritten contract that obliges it to transfer partially or entirely the income derived from Indonesia to another party.

If a particular transaction or structure is found to be misusing a tax treaty, the Indonesian payer of the income, who is obligated to withhold the tax, is not allowed to apply the benefits of the relevant tax treaty and must withhold tax which is payable in accordance with Indonesian tax regulations at the applicable rate (i.e. 20% rate). In addition, in the event that it is found that the legal form of a structure of a particular transaction is different from its economic substance, the Indonesian Tax Authority will apply the "substance over form" principle in imposing taxes in accordance with the economic substance of the transaction.

Stamp Duty

According to Government Regulation No. 24 of 2000, a document that effects a sale of Indonesian notes is subject to stamp duty. Currently, the nominal amount of the Indonesian stamp duty is Rp. 6,000 for transactions having a value greater than Rp. 1,000,000 and Rp. 3,000 for transactions having a value up to a maximum of Rp. 1,000,000. Generally, the stamp duty is due at the time the document is executed. Stamp duty is payable by the party that benefits from the executed document unless both parties state otherwise.

Other Indonesian Taxes

There are no Indonesian estate, inheritance, succession, or gift taxes generally applicable to the acquisition, ownership or disposition of the Notes. There are no Indonesian issue, registration or similar taxes or duties payable by the Noteholders as a result of their holding of the Notes.

The above summary is not intended to constitute a complete analysis of all tax consequences relating to the ownership of the Notes. Prospective investors in the Notes should consult their own tax advisors concerning the tax consequences of their particular situations.

Certain United States Federal Income Tax Considerations

The following is a summary of certain material U.S. federal income tax consequences of the acquisition, ownership and disposition of Registered Notes by a U.S. Holder (as defined below). This summary does not address the material U.S. federal income tax consequences of every type of Note which may be issued under the Program, and the relevant Pricing Supplement may contain additional or modified disclosure concerning the material U.S. federal income tax consequences relevant to such type of Note as appropriate. This summary deals only with purchasers of Notes that are U.S. Holders and that will hold the Notes as capital assets. The discussion does not cover all aspects of U.S. federal income taxation that may be relevant to, or the actual tax effect that any of the matters described herein will have on, the acquisition, ownership or disposition of Notes by particular investors, and does not address the Medicare tax on certain unearned income, alternative minimum tax considerations, or state, local, foreign or other tax laws. This summary does not discuss all of the tax considerations that may be relevant to certain types of investors subject to special treatment under the U.S. federal income tax laws (such as financial institutions, insurance companies, investors subject to special tax accounting rules as a result of any item of gross income with respect to Notes being taken into account in an applicable financial statement, individual retirement accounts and other tax-deferred accounts, tax-exempt organizations, dealers in securities or currencies, investors that will hold the Notes as part of straddles, wash sales, hedging transactions or conversion transactions for U.S. federal income tax purposes, investors whose functional currency is not the U.S. dollar or persons holding Notes in connection with a trade or business conducted outside the United States). Moreover, the summary deals only with Notes with a term of 30 years or less and does not deal with Partly Paid Notes or Dual Currency Notes. The U.S. federal income tax consequences of owning such Notes will be discussed in the applicable Pricing Supplement.

As used herein, the term "U.S. Holder" means a beneficial owner of Notes that is, for U.S. federal income tax purposes, (i) an individual citizen or resident of the United States, (ii) a corporation, or other entity treated as a corporation, created or organized under the laws of the United States, any State thereof or the District of Columbia, (iii) an estate the income of which is subject to U.S. federal income tax without regard to its source or (iv) a trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust, or the trust has elected to be treated as a domestic trust for U.S. federal income tax purposes.

The U.S. federal income tax treatment of a partner in a partnership (including any entity treated as a partnership for U.S. federal income tax purposes) that holds Notes will depend on the status of the partner and the activities of the partnership. Prospective purchasers that are partnerships should consult their tax advisers concerning the U.S. federal income tax consequences to their partners of the acquisition, ownership and disposition of Notes by the partnership.

The summary is based on the tax laws of the United States including the Internal Revenue Code, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, as well as on the income tax treaty between the United States and Indonesia (the "Treaty") all as of the date hereof and all subject to change at any time, possibly with retroactive effect.

Bearer Notes are not being offered to U.S. Holders, and this summary does not discuss Bearer Notes. A U.S. Holder who owns a Bearer Note may be subject to limitations under United States income tax laws, including the limitations provided in sections 165(j) and 1287(a) of the Internal Revenue Code.

THE SUMMARY OF U.S. FEDERAL INCOME TAX CONSEQUENCES SET OUT BELOW IS FOR GENERAL INFORMATION ONLY. PROSPECTIVE PURCHASERS SHOULD

CONSULT THEIR TAX ADVISERS AS TO THE PARTICULAR TAX CONSEQUENCES TO THEM OF OWNING THE NOTES, INCLUDING THE APPLICABILITY AND EFFECT OF STATE, LOCAL, FOREIGN AND OTHER TAX LAWS AND POSSIBLE CHANGES IN TAX LAW.

U.S. Federal Income Tax Characterization of the Notes

The characterization of a Series or Tranche of Notes may be uncertain and will depend on the terms of those Notes. The determination of whether an obligation represents debt, equity, or some other instrument or interest is based on all the relevant facts and circumstances. There may be no statutory, judicial or administrative authority directly addressing the characterization of some of the types of Notes that are anticipated to be issued under the Program or of instruments similar to the Notes.

The following summary applies to Notes that are properly treated as debt for U.S. federal income tax purposes. No rulings will be sought from the U.S. Internal Revenue Service ("IRS") regarding the characterization of any of the Notes issued hereunder for U.S. federal income tax purposes. Each holder should consult its own tax adviser about the proper characterization of the Notes for U.S. federal income tax purposes and consequences to the holder of acquiring, owning or disposing of the Notes. Possible alternative characterizations, if applicable, may be discussed in the relevant Final Terms or any Prospectus or series prospectus.

Payments of Interest

General

Interest on a Note that is "qualified stated interest" (defined below under "— Original Issue Discount — General"), will be taxable to a U.S. Holder as ordinary income at the time it is received or accrued, depending on the U.S. Holder's method of accounting for U.S. federal income tax purposes. Interest paid by the Company on the Notes and original issue discount ("OID"), if any, accrued with respect to the Notes (as described below under "— Original Issue Discount") generally will constitute income from sources outside the United States.

Effect of Indonesian Withholding Taxes

As discussed in "Taxation — Indonesian Taxation," under current law payments of interest by the Company on the Notes to investors that are not resident in Indonesia are generally subject to a 20% Indonesian withholding tax. The rate of withholding tax applicable to U.S. Holders that are eligible for benefits under the Treaty is reduced to a maximum of 10%. The Company is liable subject to exceptions, for the payment of Additional Amounts (see Condition 4 of the "Description of the Notes — Taxation") so that U.S. Holders generally should receive the same amounts they would have received had no Indonesian withholding taxes been imposed. For U.S. federal income tax purposes, U.S. Holders will be treated as having actually received the amount of any Indonesian taxes withheld by the Company with respect to a Note, which is includable in such U.S. Holder's income at the time such amount is received or accrued in accordance with such U.S. Holder's method of U.S. federal income tax accounting, and as then having actually paid over the withheld taxes to the Indonesian taxing authorities. As a result of this rule, the amount of interest income included in gross income for U.S. federal income tax purposes by a U.S. Holder with respect to a payment of interest will be greater than the amount of cash actually received (or receivable) by the U.S. Holder from the Company with respect to the payment.

Subject to certain limitations, a U.S. Holder will generally be entitled to a credit against its U.S. federal income tax liability, or a deduction in computing its U.S. federal taxable income, for

Indonesian income taxes withheld. U.S. Holders that are eligible for benefits under the Treaty will not be entitled to a foreign tax credit for the amount of any Indonesian taxes withheld in excess of the applicable maximum rate under the Treaty (generally 10%). See "Taxation — Indonesian Taxation — Anti-Avoidance Rule on the Tax Treaty and New CoD Requirements" for a discussion on how to obtain the rate of withholding tax under the Treaty. For purposes of the foreign tax credit limitation, foreign source income is classified as belonging to a specified "basket," and the credit for foreign taxes on income in any basket is limited to U.S. federal income tax allocable to that income. Interest and OID (defined below) generally will constitute foreign source income in the "passive income" basket. In certain circumstances a U.S. Holder may be unable to claim foreign tax credits (and may instead be allowed deductions) for Indonesian taxes imposed on a payment of interest if the U.S. Holder has not met certain holding period requirements. If Notes are issued with OID, since a U.S. Holder may be required to include OID on the Notes in its gross income in advance of any withholding of Indonesian income taxes from payments attributable to the OID (which would generally occur when the Note is repaid or redeemed), a U.S. Holder may not be entitled to a credit or deduction for all of the Indonesian income taxes in the year the OID is included in the U.S. Holder's gross income, and may be limited in its ability to credit or deduct in full the Indonesian taxes in the year those taxes are actually withheld by the Company. Prospective purchasers should consult their tax advisers concerning the foreign tax credit implications of the payment of these Indonesian taxes.

Original Issue Discount

General

The following is a summary of the principal U.S. federal income tax consequences of the ownership of Notes issued with OID. The following summary does not discuss Notes that are characterized as contingent payment debt instruments for U.S. federal income tax purposes. In the event the Company issues contingent payment debt instruments the applicable Pricing Supplement will describe the material U.S. federal income tax consequences thereof.

A Note, other than a Note with a term of one year or less (a "Short-Term Note"), will be treated as issued with OID (a "Discount Note") if the excess of the Note's "stated redemption price at maturity" over its issue price is equal to or more than a *de minimis* amount (0.25% of the Note's stated redemption price at maturity multiplied by the number of complete years to its maturity). A Note that provides for the payment of amounts other than qualified stated interest before maturity (an "installment obligation") will be treated as a Discount Note if the excess of the Note's stated redemption price at maturity over its issue price is equal to or greater than 0.25% of the Note's stated redemption price at maturity multiplied by the weighted average maturity of the Note. A Note's weighted average maturity is the sum of the following amounts determined for each payment on a Note (other than a payment of qualified stated interest): (i) the number of complete years from the issue date until the payment is made multiplied by (ii) a fraction, the numerator of which is the amount of the payment and the denominator of which is the Note's stated redemption price at maturity. Generally, the issue price of a Note will be the first price at which a substantial amount of Notes included in the issue of which the Note is a part is sold to persons other than bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents, or wholesalers. The stated redemption price at maturity of a Note is the total of all payments provided by the Note that are not payments of "qualified stated interest." A qualified stated interest payment is generally any one of a series of stated interest payments on a Note that are unconditionally payable in cash or in property (other than debt instruments of the issuer) at least annually during the entire term of the Note at a single fixed rate (with certain exceptions for different rates that take into account different compounding periods), or a variable rate (in the circumstances described below under "Variable Interest Rate Notes"), applied to the outstanding principal amount of the Note. Solely for the purposes of determining whether a Note has OID, the Company will be deemed to exercise any unconditional call option that has the effect of decreasing the yield on the Note, and the U.S. Holder will be deemed to exercise any unconditional put option that has the effect of increasing the yield on the Note.

U.S. Holders of Discount Notes (regardless of their method of accounting for U.S. federal income tax purposes) must include OID in income calculated on a constant-yield method before the receipt of cash attributable to the income, and generally will have to include in income increasingly greater amounts of OID over the life of the Discount Notes. The amount of OID includible in income by a U.S. Holder of a Discount Note is the sum of the daily portions of OID with respect to the Discount Note for each day during the taxable year or portion of the taxable year on which the U.S. Holder holds the Discount Note. The daily portion is determined by allocating to each day in any "accrual period" a *pro rata* portion of the OID allocable to that accrual period. Accrual periods with respect to a Discount Note may be of any length selected by the U.S. Holder and may vary in length over the term of the Discount Note as long as (i) no accrual period is longer than one year and (ii) each scheduled payment of interest or principal on the Discount Note occurs on either the final or first day of an accrual period. The amount of OID allocable to an accrual period equals the excess of (a) the product of the Discount Note's adjusted issue price at the beginning of the accrual period and the Discount Note's yield to maturity (determined on the basis of compounding at the close of each accrual period and properly adjusted for the length of each accrual period) over (b) the sum of the payments of qualified stated interest on the Discount Note allocable to the accrual period. The "adjusted issue price" of a Discount Note at the beginning of any accrual period is the issue price of the Discount Note increased by (x) the amount of accrued OID for each prior accrual period and decreased by (y) the amount of any payments previously made on the Discount Note that were not qualified stated interest payments.

The amount of OID allocable to the final accrual period is equal to the difference between: (i) the amount payable at the maturity of a Note, other than any payment of qualified stated interest, and (ii) the Note's adjusted issue price as of the beginning of the final accrual period.

Acquisition Premium

A U.S. Holder that purchases a Discount Note for an amount less than or equal to the sum of all amounts payable on the Discount Note after the purchase date, other than payments of qualified stated interest, but in excess of its adjusted issue price (any such excess being "acquisition premium") and that does not make the election described below under "— Election to Treat All Interest as Original Issue Discount," is permitted to reduce the daily portions of OID which must be included in income by a fraction, the numerator of which is the excess of the U.S. Holder's adjusted basis in the Discount Note immediately after its purchase over the Discount Note's adjusted issue price, and the denominator of which is the excess of the sum of all amounts payable on the Discount Note after the purchase date, other than payments of qualified stated interest, over the Discount Note's adjusted issue price.

Short-Term Notes

In general, an individual or other cash basis U.S. Holder of a Short-Term Note is not required to accrue OID (as specially defined below for the purposes of this paragraph) for U.S. federal income tax purposes unless it elects to do so (but the U.S. Holder may be required to include any stated interest in income as the interest is received). Accrual basis U.S. Holders and certain other U.S. Holders are required to accrue OID on Short-Term Notes on a straight-line basis or, if the U.S. Holder so elects, under the constant-yield method (based on daily compounding). In the case of a U.S. Holder not required and not electing to include OID in income currently, any gain recognized on the sale or retirement of the Short-Term Note will be ordinary income to the extent of the OID accrued on a straight-line basis (unless an election is made to accrue the OID under the constant-yield method) through the date of sale or retirement. U.S. Holders who are not required and do not elect to accrue OID on Short-Term Notes will be required to defer deductions for interest on borrowings allocable to Short-Term Notes in an amount not exceeding the deferred income until the deferred income is recognized.

For purposes of determining the amount of OID subject to these rules, all interest payments on a Short-Term Note are included in the Short-Term Note's stated redemption price at maturity. A U.S. Holder may elect to determine OID on a Short-Term Note as if the Short-Term Note had been originally issued to the U.S. Holder at the U.S. Holder's purchase price for the Short-Term Note. This election will apply to all obligations with a maturity of one year or less acquired by the U.S. Holder on or after the first day of the first taxable year to which the election applies, and may not be revoked without the consent of the IRS.

Market Discount

A Note, other than a Short-Term Note, generally will be treated as purchased at a market discount (a "Market Discount Note") if the Note's stated redemption price at maturity or, in the case of a Discount Note, the Discount Note's "revised issue price," exceeds the amount for which the U.S. Holder purchased the Note by at least 0.25% of the Note's stated redemption price at maturity or revised issue price, respectively, multiplied by the number of complete years to the Note's maturity (or, in the case of a Note that is an installment obligation, the Note's weighted average remaining maturity). If this excess is not sufficient to cause the Note to be a Market Discount Note, then the excess constitutes "*de minimis* market discount." For this purpose, the "revised issue price" of a Discount Note generally equals its issue price, increased by the amount of any OID that has accrued on the Note and decreased by the amount of any payments previously made on the Note that were not qualified stated interest payments.

Any gain recognized on the maturity or disposition of a Market Discount Note (including any payment on a Market Discount Note that is not qualified stated interest) will be treated as ordinary income to the extent the gain does not exceed the accrued market discount on the Note while held by such U.S. Holder. Alternatively, a U.S. Holder of a Market Discount Note may elect to include market discount in income currently over the life of the Note. This election will apply to all debt instruments with market discount acquired by the electing U.S. Holder on or after the first day of the first taxable year to which the election applies. This election may not be revoked without the consent of the IRS. A U.S. Holder of a Market Discount Note that does not elect to include market discount in income currently will generally be required to defer deductions for certain interest on borrowings incurred to purchase or carry a Market Discount Note, to the extent this excess interest expense does not exceed the portion of the market discount allocable to the days on which the Market Discount Note was held by the U.S. Holder.

Market discount will accrue on a straight-line basis unless the U.S. Holder elects to accrue the market discount on a constant-yield method. This election applies only to the Market Discount Note with respect to which it is made and may not be revoked without the consent of the IRS.

Variable Interest Rate Notes

It is expected that the Notes that provide for interest at variable rates ("Variable Interest Rate Notes") generally will bear interest at a "qualified floating rate" (defined below) and thus will be treated as "variable rate debt instruments" under U.S. Treasury Regulations governing accrual of OID. A Variable Interest Rate Note will qualify as a "variable rate debt instrument" if (a) its issue price does not exceed the total noncontingent principal payments due under the Variable Interest Rate Note by more than a specified *de minimis* amount, (b) it provides for stated interest, paid or compounded at least annually, at (i) one or more qualified floating rates, (ii) a single fixed rate and one or more qualified floating rates, (iii) a single objective rate, or (iv) a single fixed rate and a single objective rate that is a qualified inverse floating rate, and (c) it does not provide for any principal payments that are contingent (other than as described in (a) above).

A "qualified floating rate" is any variable rate where variations in the value of the rate can reasonably be expected to measure contemporaneous variations in the cost of newly borrowed funds in the currency in which the Variable Interest Rate Note is denominated. A fixed multiple of a qualified floating rate will constitute a qualified floating rate only if the multiple is greater than 0.65 but not more than 1.35. A variable rate equal to the product of a qualified floating rate and a fixed multiple that is greater than 0.65 but not more than 1.35, increased or decreased by a fixed rate, will also constitute a qualified floating rate. In addition, two or more qualified floating rates that can reasonably be expected to have approximately the same values throughout the term of the Variable Interest Rate Note (e.g., two or more qualified floating rates with values within 25 basis points of each other as determined on the Variable Interest Rate Note's issue date) will be treated as a single qualified floating rate. Notwithstanding the foregoing, a variable rate that would otherwise constitute a qualified floating rate but which is subject to one or more restrictions such as a maximum numerical limitation (i.e., a cap) or a minimum numerical limitation (i.e., a floor) may, under certain circumstances, fail to be treated as a qualified floating rate unless the cap or floor is fixed throughout the term of the Note.

An "objective rate" is a rate that is not itself a qualified floating rate but which is determined using a single fixed formula and that is based on objective financial or economic information (e.g., one or more qualified floating rates or the yield of actively traded personal property). A rate will not qualify as an objective rate if it is based on information that is within the control of the Company (or a related party) or that is unique to the circumstances of the Company (or a related party), such as dividends, profits or the value of the Company's stock (although a rate does not fail to be an objective rate merely because it is based on the credit quality of the Company). Other variable interest rates may be treated as objective rates if so designated by the IRS in the future. Despite the foregoing, a variable rate of interest on a Variable Interest Rate Note will not constitute an objective rate if it is reasonably expected that the average value of the rate during the first half of the Variable Interest Rate Note's term will be either significantly less than or significantly greater than the average value of the rate during the final half of the Variable Interest Rate Note's term. A "qualified inverse floating rate" is any objective rate where the rate is equal to a fixed rate minus a qualified floating rate, as long as variations in the rate can reasonably be expected to inversely reflect contemporaneous variations in the qualified floating rate. If a Variable Interest Rate Note provides for stated interest at a fixed rate for an initial period of one year or less followed by a variable rate that is either a qualified floating rate or an objective rate for a subsequent period and if the variable rate on the Variable Interest Rate Note's issue date is intended to approximate the fixed rate (i.e., the value of the variable rate on the issue date does not differ from the value of the fixed rate by more than 25 basis points), then the fixed rate and the variable rate together will constitute either a single qualified floating rate or objective rate, as the case may be.

A qualified floating rate or objective rate in effect at any time during the term of the instrument must be set at a "current value" of that rate. A "current value" of a rate is the value of the rate on any day that is no earlier than three months prior to the first day on which that value is in effect and no later than one year following that first day. If a Variable Interest Rate Note that provides for stated interest at either a single qualified floating rate or a single objective rate throughout the term thereof qualifies as a "variable rate debt instrument", then any stated interest on the Note which is unconditionally payable in cash or property (other than debt instruments of the Issuer) at least annually will constitute qualified stated interest and will be taxed accordingly. Thus, a Variable Interest Rate Note that provides for stated interest at either a single qualified floating rate or a single objective rate throughout the term thereof and that qualifies as a "variable rate debt instrument" will generally not be treated as having been issued with OID unless the Variable Interest Rate Note is issued at a "true" discount (i.e., at a price below the Note's stated principal amount) in excess of a specified *de minimis* amount. OID on a Variable Interest Rate Note arising from "true" discount is allocated to an accrual period using the constant yield method described above by assuming that the variable rate is a fixed rate equal to (i) in the case of a qualified floating rate or qualified inverse floating rate, the value, as of the issue date, of the qualified floating rate or qualified inverse floating rate, or (ii) in the case of an

objective rate (other than a qualified inverse floating rate), a fixed rate that reflects the yield that is reasonably expected for the Variable Interest Rate Note.

In general, any other Variable Interest Rate Note that qualifies as a "variable rate debt instrument" will be converted into an "equivalent" fixed rate debt instrument for purposes of determining the amount and accrual of OID and qualified stated interest on the Variable Interest Rate Note. Such a Variable Interest Rate Note must be converted into an "equivalent" fixed rate debt instrument by substituting any qualified floating rate or qualified inverse floating rate provided for under the terms of the Variable Interest Rate Note with a fixed rate equal to the value of the qualified floating rate or qualified inverse floating rate, as the case may be, as of the Variable Interest Rate Note's issue date. Any objective rate (other than a qualified inverse floating rate) provided for under the terms of the Variable Interest Rate Note is converted into a fixed rate that reflects the yield that is reasonably expected for the Variable Interest Rate Note. In the case of a Variable Interest Rate Note that qualifies as a "variable rate debt instrument" and provides for stated interest at a fixed rate in addition to either one or more qualified floating rates or a qualified inverse floating rate, the fixed rate is initially converted into a qualified floating rate (or a qualified inverse floating rate, if the Variable Interest Rate Note provides for a qualified inverse floating rate). Under these circumstances, the qualified floating rate or qualified inverse floating rate that replaces the fixed rate must be such that the fair market value of the Variable Interest Rate Note as of the Variable Interest Rate Note's issue date is approximately the same as the fair market value of an otherwise identical debt instrument that provides for either the qualified floating rate or qualified inverse floating rate rather than the fixed rate. Subsequent to converting the fixed rate into either a qualified floating rate or a qualified inverse floating rate, the Variable Interest Rate Note is converted into an "equivalent" fixed rate debt instrument in the manner described above.

Once the Variable Interest Rate Note that qualifies as a "variable rate debt instrument" is converted into an "equivalent" fixed rate debt instrument, pursuant to the foregoing rules, the amount of OID and qualified stated interest, if any, are determined for the "equivalent" fixed rate debt instrument by applying the general OID rules to the "equivalent" fixed rate debt instrument and a U.S. Holder of the Variable Interest Rate Note will account for the OID and qualified stated interest as if the U.S. Holder held the "equivalent" fixed rate debt instrument. In each accrual period, appropriate adjustments will be made to the amount of qualified stated interest and any OID assumed to have been accrued or paid with respect to the "equivalent" fixed rate debt instrument in the event these amounts differ from the actual amount of interest accrued or paid on the Variable Interest Rate Note during the accrual period.

If a Variable Interest Rate Note, such as a Note the payments on which are determined by reference to an index, does not qualify as a "variable rate debt instrument," then the Variable Interest Rate Note will be treated as a contingent payment debt obligation. The proper U.S. federal income tax treatment of Variable Interest Rate Notes that are treated as contingent payment debt obligations will be more fully described in the applicable Pricing Supplement.

Notes Purchased at a Premium

A U.S. Holder that purchases a Note for an amount in excess of its principal amount, or for a Discount Note, its stated redemption price at maturity, will generally have "amortizable bond premium" to the extent of such excess. If so, the U.S. Holder will not be required to include any OID in income. In addition, the U.S. Holder may elect to amortize such premium (or, if it results in a smaller amount, a premium computed using the amount payable by the Company on an earlier call date), in which case the amount required to be included in the U.S. Holder's income each year with respect to qualified stated interest on the Note will be reduced by the amount of amortizable bond premium allocable (based on the Note's yield to maturity) to that year. Any election to amortize bond

premium will apply to all bonds (other than bonds the interest on which is excludable from gross income for U.S. federal income tax purposes) held by the U.S. Holder at the beginning of the first taxable year to which the election applies or thereafter acquired by the U.S. Holder, and is irrevocable without the consent of the IRS. See also "— Original Issue Discount — Election to Treat All Interest as Original Issue Discount."

Election to Treat All Interest as Original Issue Discount

A U.S. Holder may elect to include in gross income all interest that accrues on a Note using the constant-yield method described above under "— Original Issue Discount — General," with certain modifications. For purposes of this election, interest includes stated interest, acquisition discount, OID, *de minimis* OID, market discount, *de minimis* market discount and unstated interest, as adjusted by any amortizable bond premium (described above under "— Notes Purchased at a Premium") or acquisition premium. This election will generally apply only to the Note with respect to which it is made and may not be revoked without the consent of the IRS. If the election to apply the constant-yield method to all interest on a Note is made with respect to a Market Discount Note, the electing U.S. Holder will be treated as having made the election discussed above under "— Market Discount" to include market discount in income currently over the life of all debt instruments with market discount held or thereafter acquired by the U.S. Holder on or after the first day of the first taxable year to which the election applies, and if the election to apply the constant yield method to all interest on a Note is made with respect to a Note purchased at a premium, the electing U.S. Holder will be treated as having made the election discussed above under "— Notes Purchased at a Premium" to amortize bond premium on all taxable bonds held or thereafter acquired by the U.S. Holder. U.S. Holders should consult their tax advisers concerning the propriety and consequences of this election.

Purchase, Sale and Retirement of Notes

A U.S. Holder's adjusted tax basis in a Note will generally be its cost, increased by the amount of any OID or market discount included in the U.S. Holder's income with respect to the Note and the amount, if any, of income attributable to de minimis OID and de minimis market discount included in the U.S. Holder's income with respect to the Note, and reduced by (i) the amount of any payments that are not qualified stated interest payments, and (ii) the amount of any amortizable bond premium previously applied to reduce interest on the Note.

A U.S. Holder will generally recognize gain or loss on the sale or retirement of a Note equal to the difference between the amount realized on the sale or retirement and the tax basis of the Note. The amount realized does not include the amount attributable to accrued but unpaid interest, which will be taxable as interest income to the extent not previously included in income. Except to the extent described above under "— Original Issue Discount — Market Discount" or "— Original Issue Discount — Short Term Notes" or attributable to changes in exchange rates (as discussed below), gain or loss recognized on the sale or retirement of a Note will be capital gain or loss and will be long-term capital gain or loss if the U.S. Holder's holding period in the Notes exceeds one year.

Gain or loss realized by a U.S. Holder on the sale or retirement of a Note generally will be U.S. source. Therefore, a U.S. Holder may not be able to utilize foreign tax credits attributable to any Indonesian withholding tax imposed on the sale or disposition of a Note unless such holder has foreign source income in the same category from other sources. See "Taxation — Indonesian Taxation." Prospective purchasers should consult their tax advisers as to the foreign tax implications of the sale or disposition of Notes.

Foreign Currency Notes

Interest

If an interest payment is denominated in, or determined by reference to, a foreign currency (for this purpose, meaning a non-U.S. dollar currency), the amount of income recognized by a cash basis U.S. Holder will generally be the U.S. dollar value of the interest payment, based on the exchange rate in effect on the date of receipt, regardless of whether the payment is in fact converted into U.S. dollars.

An accrual basis U.S. Holder may determine the amount of income recognized with respect to an interest payment denominated in, or determined by reference to, a foreign currency in accordance with either of two methods. Under the first method, the amount of income accrued will be based on the average exchange rate in effect during the interest accrual period (or, in the case of an accrual period that spans two taxable years of a U.S. Holder, the part of the period within the taxable year).

Under the second method, the U.S. Holder may elect to determine the amount of income accrued on the basis of the exchange rate in effect on the last day of the accrual period (or, in the case of an accrual period that spans two taxable years, the exchange rate in effect on the last day of the part of the period within the taxable year). Additionally, if a payment of interest is actually received within five business days of the last day of the accrual period, an electing accrual basis U.S. Holder may instead translate the accrued interest into U.S. dollars at the exchange rate in effect on the day of actual receipt. Any such election will apply to all debt instruments held by the U.S. Holder at the beginning of the first taxable year to which the election applies or thereafter acquired by the U.S. Holder, and will be irrevocable without the consent of the IRS.

Upon receipt of an interest payment (including a payment attributable to accrued but unpaid interest upon the sale or retirement of a Note) denominated in, or determined by reference to, a foreign currency, the U.S. Holder may recognize U.S. source exchange gain or loss (taxable as ordinary income or loss) equal to the difference between the amount received (translated into U.S. dollars at the spot rate on the date of receipt) and the U.S. dollar amount previously accrued, regardless of whether the payment is in fact converted into U.S. dollars.

OID

OID for each accrual period on a Discount Note that is denominated in, or determined by reference to, a foreign currency will be determined in the foreign currency and then translated into U.S. dollars in the same manner as stated interest accrued by an accrual basis U.S. Holder, as described above.

Upon receipt of an amount attributable to OID (whether in connection with a payment on the Note or a sale of the Note), a U.S. Holder may recognize U.S. source exchange gain or loss (taxable as ordinary income or loss) equal to the difference between the amount received (translated into U.S. dollars at the spot rate on the date of receipt) and the amount previously accrued, regardless of whether the payment is in fact converted into U.S. dollars.

Market Discount

Market discount on a Note that is denominated in, or determined by reference to, a foreign currency will be accrued in the foreign currency. If the U.S. Holder elects to include market discount in income currently, the accrued market discount will be translated into U.S. dollars at the average exchange rate for the accrual period (or portion thereof within the U.S. Holder's taxable year). Upon the receipt of an amount attributable to accrued market discount, the U.S. Holder may recognize U.S.

source exchange gain or loss (which will be taxable as ordinary income or loss) determined in the same manner as for accrued interest or OID. A U.S. Holder that does not elect to include market discount in income currently will recognize, upon the disposition or maturity of the Note, the U.S. dollar value of the amount accrued, calculated at the spot rate on that date, and no part of this accrued market discount will be treated as exchange gain or loss.

Bond Premium

Bond premium (including acquisition premium) on a Note that is denominated in, or determined by reference to, a foreign currency, will be computed in units of the foreign currency, and any such bond premium that is taken into account currently will reduce interest income in units of the foreign currency. On the date bond premium offsets interest income, a U.S. Holder may recognize U.S. source exchange gain or loss (taxable as ordinary income or loss) measured by the difference between the spot rate in effect on that date and on the date the Notes were acquired by the U.S. Holder. A U.S. Holder that does not elect to take bond premium (other than acquisition premium) into account currently will recognize a capital loss to the extent of the bond premium when the Note matures.

Sale or Retirement

As discussed above under "Purchase, Sale and Retirement of Notes," a U.S. Holder will generally recognize gain or loss on the sale or retirement of a Note equal to the difference between the amount realized on the sale or retirement and its tax basis in the Note. A U.S. Holder's tax basis in a Note that is denominated in a foreign currency will be determined by reference to the U.S. dollar cost of the Note. The U.S. dollar cost of a Note purchased with foreign currency will generally be the U.S. dollar value of the purchase price on the date of purchase or, in the case of Notes traded on an established securities market, as defined in the applicable Treasury Regulations, that are purchased by a cash basis U.S. Holder (or an accrual basis U.S. Holder that so elects) on the settlement date for the purchase.

The amount realized on a sale or retirement of a Note for an amount in foreign currency will be the U.S. dollar value of this amount on the date of sale or retirement or, in the case of Notes traded on an established securities market, as defined in the applicable Treasury Regulations, sold by a cash basis U.S. Holder (or an accrual basis U.S. Holder that so elects) on the settlement date for the sale. Such an election by an accrual basis U.S. Holder must be applied consistently from year to year and cannot be revoked without the consent of the IRS.

A U.S. Holder will recognize U.S. source exchange gain or loss (taxable as ordinary income or loss) on the sale or retirement of a Note equal to the difference, if any, between the U.S. dollar values of the principal amount (which is generally considered to equal the purchase price, adjusted for previously amortized bond premium or previously accrued market discount) of the Note on (i) the date of sale or retirement and (ii) the date on which the U.S. Holder acquired the Note. Any such exchange gain or loss will be realized only to the extent of total gain or loss realized on the sale or retirement of the Note.

Backup Withholding and Information Reporting

In general, payments of interest and accruals of OID on, and the proceeds of a sale, redemption or other disposition of, the Notes, payable to a U.S. Holder by a U.S. paying agent or other U.S. intermediary will be reported to the IRS and to the U.S. Holder to the extent required under applicable regulations. Backup withholding will apply to these payments, including payments of OID, if the U.S. Holder fails to provide an accurate taxpayer identification number or certification of exempt status or if the U.S. Holder had been notified that it is subject to backup withholding because of a failure to

report all interest and dividends required to be shown on its U.S. federal income tax returns. Certain U.S. Holders are not subject to backup withholding. The amount of any backup withholding from a payment to a U.S. Holder will be allowed as a credit against such U.S. Holder's U.S. federal income tax liability and may entitle such U.S. Holder to a refund, provided that the required information is timely furnished to the IRS and certain other requirements are met. U.S. Holders should consult their tax advisers as to their qualification for exemption from backup withholding and the procedure for obtaining an exemption.

Certain U.S. Holders who are individuals (or certain entities) may be required to report information relating to an interest in the Notes, subject to certain exceptions (including an exception for Notes held in accounts maintained with non-U.S. financial institutions). U.S. Holders who fail to report required information could become subject to substantial penalties. U.S. Holders should consult their tax advisers regarding the effect, if any, of this requirement on their ownership and disposition of the Notes.

Reportable Transactions

U.S. Treasury Regulations require a U.S. taxpayer that participates in a "reportable transaction" to disclose this participation to the IRS. The scope and application of these rules is not entirely clear. A U.S. Holder may be required to treat a foreign currency exchange loss from the Notes as a reportable transaction if the loss exceeds US$50,000 in a single taxable year, if the U.S. Holder is an individual or trust, or higher amounts for other non-individual U.S. Holders. In the event the acquisition, ownership or disposition of Notes constitutes participation in a "reportable transaction" for purposes of these rules, a U.S. Holder will be required to disclose its investment by filing Form 8886 with the IRS. A penalty in the amount of US$10,000 in the case of a natural person and US$50,000 in all other cases is generally imposed on any taxpayer that fails to timely file an information return with the IRS with respect to a transaction resulting in a loss that is treated as a reportable transaction.

PLAN OF DISTRIBUTION

Summary of the Program Agreement

Subject to the terms and conditions contained in an amended and restated program agreement dated October 19, 2018, as amended and supplemented from time to time (the "Program Agreement"), between the Company, the Arrangers and the Dealers, the Notes may be offered on a continuous basis by the Company to the Dealers. The Notes may be resold at prevailing market prices, or at prices related thereto, at the time of such resale, as determined by the Relevant Dealer(s). The Notes may also be sold by the Company through the Dealers, acting as agents of the Company. The Program Agreement also provides for Notes to be issued in syndicated Tranches that are jointly and severally underwritten by two or more Dealers.

The Company will pay the Relevant Dealer a commission as agreed between them in respect of Notes subscribed by it. The Company has agreed to reimburse each of the Arrangers for certain of its expenses incurred in connection with the establishment of the Program and the Dealers for certain of their activities in connection with the Program.

The Company has agreed to indemnify the Dealers against certain liabilities in connection with the offer and sale of the Notes. The Program Agreement entitles the Dealers to terminate any agreement that they make to subscribe Notes in certain circumstances prior to payment for such Notes being made to the Company.

Other Relationships

The Dealers and their affiliates may, from time to time, engage in transactions with and perform services for the Company, its subsidiaries and to affiliates in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses. It is expected that the Dealers and their respective affiliates will continue to provide such services to, and enter into such transactions with, the Company and its subsidiaries and affiliates in the future.

In addition, in the ordinary course of their various business activities, the Dealers and their respective affiliates may make or hold (on their own account, on behalf of clients or in their capacity of investment advisers) a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments and enter into other transactions, including credit derivatives (such as asset swaps, repackaging and credit default swaps) in relation thereto. Such transactions, investments and securities activities may involve securities and instruments of the Company or its subsidiaries, jointly controlled entities or associated entities, including Notes offered hereby, may be entered into at the same time or proximate to offers and sales of Notes or at other times in the secondary market and may be carried out with counterparties that are also purchasers, holders or sellers of Notes. The Dealers or their respective affiliates may purchase Notes and be allocated Notes for asset management and/or proprietary purposes and not with a view to distribution. The Dealers and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments. In addition, one of the Dealers, Mandiri Securities Pte. Ltd., is an entity that is, with us, under common control by the Government.

In connection with the offering of any Notes, each Dealer and/or its affiliate(s) may act as an investor for its own account and may take up Notes in the offering and in that capacity may retain,

purchase or sell for its own account such securities and any securities of the Company or related investments and may offer or sell such securities or other investments otherwise than in connection with the offering. Accordingly, references herein to Notes being offered should be read as including any offering of Notes to the Dealers and/or their affiliates acting in such capacity. Such persons do not intend to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligation to do so.

Selling Restrictions

General

The Notes have not been and will not be registered under the laws of any jurisdiction, nor has any other action been taken, nor will any action be taken, by the Company, the Dealers or any other person that would permit a public offering of the Notes or the possession, circulation or distribution of this Offering Memorandum or any supplement hereto or thereto, or any other offering material relating to the Company or the Notes, in any country or jurisdiction where action for any such purpose may be required. The offer and sale of Notes, and the delivery of this Offering Memorandum, are restricted by law in certain jurisdictions and Notes may not be offered or sold, and this Offering Memorandum may not be distributed, in any jurisdiction under circumstances where such offer, sale or distribution would be prohibited or restricted by law.

Without limiting the foregoing, prospective purchasers of Notes should be aware of the following restrictions:

European Economic Area

Prohibition of Sales to EEA Retail Investors

Unless the relevant Pricing Supplement in respect of any Notes specifies the "Prohibition of Sales to EEA Retail Investors" as "Not Applicable," each Dealer (severally, and not jointly) has represented, warranted and agreed that it has not offered, sold or otherwise made available and will not offer, sell or otherwise make available any Notes which are the subject of the offering contemplated by this Offering Memorandum as completed by the Pricing Supplement in relation thereto to any retail investor in the European Economic Area. For the purposes of this provision:

(a) the expression "retail investor" means a person who is one (or more) of the following:

(i) a retail client as defined in point (11) of Article 4(1) of MiFID II;

(ii) a customer within the meaning of the Insurance Mediation Directive, where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; and

(iii) not a qualified investor as defined in the Prospectus Directive; and

(b) the expression an "offer" includes the communication in any form and by any means of sufficient information on the terms of the offer and the Notes to be offered so as to enable an investor to decide to purchase or subscribe the Notes.

If the Pricing Supplement in respect of any Notes specifies "Prohibition of Sales to EEA Retail Investors" as "Not Applicable," each Dealer has represented and agreed, in relation to each Member

State of the European Economic Area which has implemented the Prospectus Directive (each, a "Relevant Member State"), that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the "Relevant Implementation Date") it has not made and will not make an offer of Notes which are the subject of the offering contemplated by this Offering Memorandum as completed by the relevant Pricing Supplement in relation thereto to the public in that Relevant Member State, except that it may, with effect from and including the Relevant Implementation Date, make an offer of such Notes to the public in that Relevant Member State:

(a) if the relevant Pricing Supplement in relation to the Notes specify that an offer of those Notes may be made other than pursuant to Article 3(2) of the Prospectus Directive in that Relevant Member State (a "Non-exempt Offer"), following the date of publication of a prospectus in relation to such Notes which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, provided that any such prospectus has subsequently been completed by the relevant Pricing Supplement contemplating such Non-exempt Offer, in accordance with the Prospectus Directive, in the period beginning and ending on the dates specified in such prospectus or Pricing Supplement, as applicable, and the Issuer has consented in writing to its use for the purpose of that Non-exempt Offer;

(b) *Qualified investors*: at any time to any legal entity which is a "qualified investor" as defined in the Prospectus Directive;

(c) *Fewer than 150 offerees*: at any time to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the Issuer for any such offer; or

(d) *Other exempt offers*: at any time in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of Notes referred to in (b) to (d) above shall require the Issuer or any Dealer to publish a prospectus pursuant to Article 3 of the Prospectus Directive or supplement a prospectus pursuant to Article 16 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of Notes to the public" in relation to any Notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the Notes to be offered so as to enable an investor to decide to purchase or subscribe the Notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive to the extent implemented in the Relevant Member State, and as further amended or superseded, including by Regulation (EU) 2017/1129 (effective July 21, 2019)), and includes any relevant implementing measure in each Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

United Kingdom

Each Dealer has represented, warranted and agreed that:

(a) in relation to any Notes which have a maturity of less than one year, (1) it is a person whose ordinary activities involve it in acquiring, holding, managing or disposing of

investments (as principal or agent) for the purposes of its business and (2) it has not offered or sold and will not offer or sell any Notes other than to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or as agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses where the issue of the Notes would otherwise constitute a contravention of Section 19 of the Financial Services and Markets Act 2000 (the "FSMA") by the Issuer;

(b) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of any Notes in circumstances in which Section 21(1) of the FSMA does not apply to the Issuer or the Guarantor; and

(c) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to such Notes in, from or otherwise involving the United Kingdom.

Hong Kong

Each Dealer has represented and agreed that (1) it has not offered or sold and will not offer or sell in Hong Kong, by means of any document, any Notes other than (i) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571) of Hong Kong (the "Securities and Futures Ordinance") and any rules made under that Ordinance, except for Notes which are a "structured product" as defined in the Securities and Futures Ordinance or any rules made under the Ordinance; or (ii) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32) of Hong Kong or which do not constitute an offer to the public within the meaning of that Ordinance; and (2) it has not issued or had in its possession for the purposes of issue, and will not issue or have in its possession for the purposes of issue, whether in Hong Kong or elsewhere, any advertisement, invitation or document relating to the Notes, which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to Notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance and any rules made under that Ordinance.

Italy

Each Dealer has represented and agreed that the offer of the Notes has not been registered with the Italian Securities and Exchange Commission (Commissione Nazionale per le Società e la Borsa, the "CONSOB") pursuant to Italian securities legislation and, accordingly, each Dealer has represented and agreed that no Notes may be offered, sold or distributed, to the public in the Republic of Italy ("Italy") nor may copies of this Offering Memorandum or of any other document relating to the Notes be distributed in Italy, except:

(a) to qualified investors (*investitori qualificati*), as defined in Article 2, paragraph (e) of the Prospectus Directive as implemented by Article 34-*ter* of CONSOB Regulation No. 11971 of May 14, 1999, as amended from time to time (the "Issuers Regulation"); or

(b) in any other circumstances where an express exemption from compliance with the restrictions on offers to the public applies, as provided under Article 100 of the Italian Legislative Decree No. 58 of February 24, 1998, as amended from time to time, (the "Financial Services Act") and Article 34-*ter* of the Issuers Regulation.

Moreover, and subject to the foregoing, each Dealer has represented and agreed that any offer, sale or delivery of the Notes or distribution of copies of this Offering Memorandum or any other document relating to the Notes in Italy under (i) or (ii) above must be:

(1) made by an investment firm, bank or financial intermediary permitted to conduct such activities in Italy in accordance with the Financial Services Act, CONSOB Regulation No. 16190 of October 29, 2007, as amended from time to time, and Legislative Decree No. 385 of September 1, 1993, as amended from time to time (the "Banking Act");

(2) in compliance with Article 129 of the Banking Act and the implementing guidelines of the Bank of Italy, as amended from time to time, pursuant to which the Bank of Italy requests information on the issue or the offer of securities in Italy; and

(3) in compliance with any other applicable laws and regulations or requirement imposed by the Bank of Italy, CONSOB or other Italian authority.

Any investor purchasing the Notes in the offering is solely responsible for ensuring that any offer or resale of the Notes it purchased in the offering occurs in compliance with applicable Italian laws and regulations.

Switzerland

Each dealer has acknowledged and agreed that the Notes may not be publicly offered, sold, or advertised, directly or indirectly, in, into or from Switzerland, and will not be listed on SIX Swiss Exchange ("SIX") or on any other exchange or regulated trading facility in Switzerland. This Offering Memorandum has been prepared without regard to the disclosure standards for issuance prospectuses under article 652a or article 1156 of the Swiss Code of Obligations, or the disclosure standards for listing prospectuses under article 27 et seq. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland, or the rules related to prospectuses under Swiss Federal Act on Collective Investment Schemes. Neither this Offering Memorandum nor any other offering or marketing material relating to the Notes or the offering of the Notes under the Program may be publicly distributed or otherwise made publicly available in Switzerland.

Each dealer has further acknowledged and agreed that neither this Offering Memorandum nor any other offering or marketing material relating to the offering of the Notes under the Program, the Issuer or the Notes have been or will be filed with or approved by any Swiss regulatory authority. In particular, this Offering Memorandum will not be filed with, and the offer of Notes will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA ("FINMA"). Acquirers of the Notes will not benefit from protection or supervision by FINMA.

Indonesia

This Offering does not constitute a public offering in Indonesia under Law Number 8 of 1995 on Capital Markets. The Offering Memorandum may not be distributed in Indonesia and Notes under the Program may not be offered or sold in Indonesia or to Indonesian citizens wherever they are domiciled, or to Indonesian residents in a manner which constitutes a public offer under the laws of Indonesia.

Singapore

Each Dealer has acknowledged that this Offering Memorandum has not been nor will be registered as a prospectus with the Monetary Authority of Singapore (the "MAS"). Accordingly, each Dealer has

represented, warranted and agreed that it has not offered or sold any Notes or caused such Notes to be made the subject of an invitation for subscription or purchase and will not offer or sell such Notes or cause the Notes to be made the subject of an invitation for subscription or purchase, and has not circulated or distributed, nor will it circulate or distribute, this Offering Memorandum or any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of such Notes, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor (as defined in Section 4A the SFA) under Section 274 of the SFA, (ii) to a relevant person (as defined in Section 275(2) of the SFA) pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275, of the SFA and (where applicable) Regulation 3 of the Securities and Futures (Classes of Investors) Regulations 2018, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Note:

This Offering Memorandum has not been nor will be registered as a prospectus with the MAS. Accordingly, this Offering Memorandum and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Notes may not be circulated or distributed, nor may the Notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor (as defined in Section 4A of the SFA) under Section 274 of the SFA, (ii) to a relevant person (as defined in Section 275(2) of the SFA) pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275, of the SFA and (where applicable) Regulation 3 of the Securities and Futures (Classes of Investors) Regulations 2018, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the Notes are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

(a) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

the securities or securities-based derivatives contracts (each as defined in Section 2(1) of the SFA) of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the Notes pursuant to an offer made under Section 275 of the SFA, except:

(1) to an institutional investor or to a relevant person, or to any person from an offer referred to in Section 275(1A) or 276(4)(i)(B) of the SFA;

(2) where no consideration is or will be given for the transfer;

(3) where the transfer is by operation of law;

(4) as specified in Section 276(7) of the SFA; or

(5) as specified in Regulation 37A of the Securities and Futures (Offers of Investments) (Securities and Securities-based Derivatives Contracts) Regulations 2018.

Any reference to the SFA is a reference to the Securities and Futures Act, Chapter 289 of Singapore and a reference to any term as defined in the SFA or any provision in the SFA is a reference to that term as modified or amended from time to time by such of its subsidiary legislation as may be applicable at the relevant time.

United States

The Notes have not been and will not be registered under the Securities Act and, subject to certain exceptions, may not be offered or sold within the United States. Each Dealer has agreed, and each further Dealer appointed under the Program will be required to agree, that it will not offer or sell any Notes within the United States, except as permitted by the Program Agreement.

Bearer Notes are subject to U.S. tax law requirements and may not be offered, sold or delivered within the United States or its possessions or to a United States person, except in certain transactions permitted by U.S. tax regulations. Terms used in this paragraph have the meanings given to them by the Internal Revenue Code and regulations thereunder.

The Notes are being offered and sold outside the United States in reliance on Regulation S. The Program Agreement provides that the Dealers may directly or through their respective U.S. broker-dealer affiliates arrange for the offer and resale of Notes within the United States only to qualified institutional buyers in reliance on Rule 144A.

In addition, until 40 days after the commencement of the offering of any identifiable Tranche of Notes, an offer or sale of Notes within the United States by any Dealer (whether or not participating in the offering of such Tranche of Notes) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A.

This Offering Memorandum has been prepared by the Company for use in connection with the offer and sale of the Notes outside the United States and for the resale of the Notes in the United States. The Company and the Dealers reserve the right to reject any offer to purchase the Notes, in whole or in part, for any reason. This Offering Memorandum does not constitute an offer to any person in the United States or to any U.S. person, other than any qualified institutional buyer within the meaning of Rule 144A to whom an offer has been made directly by one of the Dealers or its U.S. broker dealer affiliate. Distribution of this Offering Memorandum by any non-U.S. person outside the United States or by any qualified institutional buyer in the United States to any U.S. person or to any other person within the United States, other than any qualified institutional buyer and those persons, if any, retained to advise such non U.S. person or qualified institutional buyer with respect thereto, is unauthorized and any disclosure without the prior written consent of the Company of any of its contents to any such U.S. person or other person within the United States, other than any qualified institutional buyer and those persons, if any, retained to advise such non-U.S. person or qualified institutional buyer, is prohibited.

Japan

The Notes have not been and will not be registered under the Financial Instruments and Exchange Act of Japan (Act No. 25 of 1948, as amended; the "FIEA") and each Dealer has represented and agreed that it has not directly or indirectly offered or sold and will not offer or sell any Notes, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (as defined under Item 5,

Paragraph 1, Article 6 of the Foreign Exchange and Foreign Trade Act (Act No. 228 of 1949, as amended)), or to others for re offering or resale, directly or indirectly, in Japan or to, or for the benefit of, a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the FIEA and any other applicable laws, regulations and ministerial guidelines of Japan.

Malaysia

This Offering Memorandum has not been and will not be registered as a prospectus with the Securities Commission of Malaysia under the Malaysian Capital Markets and Services Act 2007 ("CMSA"). Accordingly, this Offering Memorandum or any other document or material in connection therewith will not be circulated or distributed, nor will any invitation, offer or sale, directly or indirectly, be made in Malaysia with respect to offer or sale of Notes, other in circumstances falling within any one of the categories specified in Schedules 6, 7, 8 and 9 of the CMSA, subject to any law, order, regulation or official directive of Central Bank of Malaysia, Securities Commission of Malaysia and/or any other regulatory authority from time to time. Any invitation or offer of Notes in Malaysia shall only be binding upon obtaining the approval of the Securities Commission of Malaysia for the invitation or offer in respect of the Notes. Such approval shall not however, be taken to indicate that the Securities Commission of Malaysia recommends the purchase or subscription of the Notes. In addition, residents of Malaysia may be required to obtain relevant regulatory approvals including approval from the Controller of Foreign Exchange to purchase the Notes. It is the responsibility of such residents to obtain such regulatory approvals and none of the Dealers is responsible for any invitation, offer, sale or purchase of the Notes as aforesaid without the necessary approvals being in place.

General

Each Dealer has agreed or will agree that it will (to the best of its knowledge and belief) comply with all applicable securities laws and regulations in force in any jurisdiction in which it purchases, offers, sells or delivers Notes or possesses or distributes this Offering Memorandum and will obtain any consent, approval or permission required by it for the purchase, offer, sale or delivery by it of Notes under the laws and regulations in force in any jurisdiction to which it is subject or in which it makes such purchases, offers, sales or deliveries and neither the Company nor any other Dealer shall have any responsibility therefor.

Neither the Company nor any of the Dealers represents that Notes may at any time lawfully be sold in compliance with any applicable registration or other requirements in any jurisdiction, or pursuant to any exemption available thereunder, or assumes any responsibility for facilitating such sale.

With regard to each Tranche, the Relevant Dealer(s) will be required to comply with such other additional restrictions as the Company and the Relevant Dealer(s) shall agree and as shall be set forth in the applicable Pricing Supplement.

Purchasers of Notes sold by the Dealers may be required to pay stamp taxes and other charges in accordance with the laws and practices of the country of purchase in addition to the offering price and accrued interest, if any.

Each Series or Tranche of Notes is a new issue of securities with no established trading market. Any one or more of the Dealers may make a market in the Notes, but are not obliged to do so and may discontinue any market-marking, if commenced, at any time without notice. No assurance can be given as to the liquidity of the trading markets for the Notes.

Stabilization

In connection with the issue of Notes in any Series or Tranche under the Program, the Relevant Dealer or Relevant Dealers (if any) named as the Stabilizing Manager(s) (or persons acting on behalf of any Stabilizing Manager(s)) in the applicable Pricing Supplement may over-allot Notes or effect transactions with a view to supporting the market price of the Notes in such a Series at a level higher than that which might otherwise prevail. However, there is no assurance that the Stabilizing Manager (or persons acting on behalf of a Stabilizing Manager) will undertake stabilization action. Any stabilization will be conducted in accordance with all applicable laws and regulations.

TRANSFER RESTRICTIONS

As a result of the following restrictions, purchasers of Notes in the United States are advised to consult legal counsel prior to making any offer, resale, pledge or transfer of Notes.

Each prospective purchaser of Notes that have a legend regarding restrictions on transferability by accepting delivery of this Offering Memorandum, will be deemed to have represented and agreed that this Offering Memorandum is personal to such offeree and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire Notes. Distribution of this Offering Memorandum, or disclosure of any of its contents to any person other than such offeree and those persons, if any, retained to advise such offeree with respect thereto is unauthorized, and any disclosure of any of its contents, without the prior written consent of the Company, is prohibited.

The Notes have not been and will not be registered under the Securities Act or any state securities laws in the United States, and may not be offered or sold in the United States except pursuant to an effective registration statement or in accordance with an applicable exemption from the registration requirements of the Securities Act. Accordingly, the Notes are being offered and sold in the United States only to persons reasonably believed to be QIBs pursuant to Rule 144A. The international offering is being made outside the United States to non-U.S. persons in offshore transactions pursuant to Regulation S.

Sales within the United States

Each purchaser of Notes within the United States pursuant to Rule 144A by accepting this Offering Memorandum will be deemed to have represented, agreed and acknowledged as follows:

- It is (a) a QIB, (b) acquiring such Notes for its own account or for the account of a QIB and (c) aware, and each beneficial owner of such Notes has been advised, that the sale of such Notes to it is being made in reliance on Rule 144A.

- The Notes have not been and will not be registered under the Securities Act and may not be offered, sold, pledged or otherwise transferred except (a) in accordance with Rule 144A to a person that it and any person acting on its behalf reasonably believe is a QIB purchasing for its own account or for the account of a QIB, (b) in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S or (c) pursuant to an exemption from registration under the Securities Act provided by Rule 144 thereunder (if available), in each case in accordance with any applicable securities laws of any state of the United States.

- Such Notes, for compliance with applicable law, will bear a legend to the following effect:

"THIS NOTE (OR ITS PREDECESSOR) HAS NOT BEEN AND WILL NOT BE REGISTERED UNDER, AND WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER, THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") AND APPLICABLE SECURITIES LAWS OF THE STATES AND OTHER JURISDICTIONS OF THE UNITED STATES, AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS NOTE MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A THEREUNDER. TERMS USED HEREIN HAVE THE MEANINGS GIVEN THEM IN REGULATION S UNDER THE SECURITIES ACT.

THE HOLDER OF THIS NOTE BY ITS ACCEPTANCE HEREOF, REPRESENTS AND AGREES FOR THE BENEFIT OF THE COMPANY AND THE DEALERS THAT (A) IT AND ANY ACCOUNT FOR WHICH IT IS ACTING IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) AND THAT IT EXERCISES SOLE INVESTMENT DISCRETION WITH RESPECT TO EACH SUCH ACCOUNT, (B) THIS NOTE MAY BE RESOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) IN THE UNITED STATES TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) IN A TRANSACTION MEETING THE REQUIREMENTS OF SUCH RULE 144A, (2) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE) OR (4) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, AND IN EACH OF SUCH CASES IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OR OTHER JURISDICTION OF THE UNITED STATES, AND (C) THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS NOTE FROM IT OF THE TRANSFER RESTRICTIONS REFERRED TO IN (B) ABOVE.

[FOR THE PURPOSES OF APPLYING THE ORIGINAL ISSUE DISCOUNT RULES UNDER THE INTERNAL REVENUE CODE OF 1986, AS AMENDED, (1) THE ISSUE DATE OF THIS NOTE IS ; (2) THE ISSUE PRICE OF THIS NOTE IS ; (3) THE YIELD TO MATURITY IS % (COMPOUNDED SEMIANNUALLY); AND (4) THIS NOTE IS BEING ISSUED WITH ORIGINAL ISSUE DISCOUNT IN THE AMOUNT OF [U.S.$] PER U.S.$1,000 PRINCIPAL AMOUNT.]

- It understands that the Company, the Registrar, the Arrangers, the Dealers and their affiliates, and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations and agreements. If it is acquiring any Notes for the account of one or more QIBs it represents that it has sole investment discretion with respect to each such account and that it has full power to make the foregoing acknowledgements, representations and agreements on behalf of each such account.

- It understands that the Notes offered in reliance on Rule 144A will be represented by the Restricted Global Security. Before any interest in the Restricted Global Security may be offered, sold, pledged or otherwise transferred to a person who takes delivery in the form of an interest in the Unrestricted Global Security, it will be required to provide the Registrar with a written certification (in the form provided in the Indenture) as to compliance with applicable securities laws.

Each Certificated Security that is offered and sold in the United States to an Institutional Accredited Investor pursuant to Section 4(a)(2) of the Securities Act or in a transaction otherwise exempt from registration under the Securities Act will bear a legend to the following effect, in addition to such other legends as may be necessary or appropriate for compliance with applicable law:

"THIS NOTE (OR ITS PREDECESSOR) HAS NOT BEEN AND WILL NOT BE REGISTERED UNDER, AND WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER, THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") AND UNDER APPLICABLE SECURITIES LAWS OF THE STATES AND OTHER JURISDICTIONS OF THE UNITED STATES, AND MAY NOT BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS NOTE ACKNOWLEDGES FOR THE BENEFIT OF THE COMPANY AND THE DEALERS THE

RESTRICTIONS ON THE TRANSFER OF THIS NOTE SET FORTH BELOW AND AGREES THAT IT SHALL TRANSFER THIS NOTE ONLY AS PROVIDED IN THE INDENTURE ENTERED INTO BY THE COMPANY AND THE TRUSTEE AS OF MAY 3, 2013. THE PURCHASER REPRESENTS THAT IT IS AN INSTITUTIONAL "ACCREDITED INVESTOR" (WITHIN THE MEANING OF RULE 501(A)(1), (2), (3) OR (7) UNDER THE SECURITIES ACT) AND IT IS ACQUIRING THIS NOTE FOR INVESTMENT PURPOSES ONLY AND NOT WITH A VIEW TO ANY RESALE OR DISTRIBUTION HEREOF, SUBJECT TO ITS ABILITY TO RESELL THIS NOTE PURSUANT TO RULE 144A OR REGULATION S UNDER THE SECURITIES ACT OR AS OTHERWISE PROVIDED BELOW AND SUBJECT IN ANY CASE TO ANY REQUIREMENT OF LAW THAT THE DISPOSITION OF THE PROPERTY OF ANY PURCHASER SHALL AT ALL TIMES BE AND REMAIN WITHIN ITS CONTROL.

THE HOLDER OF THIS NOTE BY ITS ACCEPTANCE HEREOF AGREES TO OFFER, RESELL OR OTHERWISE TRANSFER SUCH NOTE, PRIOR TO THE DATE (THE "RESALE RESTRICTION TERMINATION DATE") WHICH IS ONE YEAR AFTER THE LATER OF THE ORIGINAL ISSUE DATE HEREOF AND THE LAST DATE ON WHICH THE COMPANY WAS THE OWNER OF THIS NOTE (OR ANY PREDECESSOR OF SUCH NOTE), ONLY (A) IN THE UNITED STATES TO A PERSON WHOM IT REASONABLY BELIEVES IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) THAT PURCHASES FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER IN A TRANSACTION MEETING THE REQUIREMENTS OF SUCH RULE 144A, (B) INSIDE THE UNITED STATES TO AN INSTITUTIONAL "ACCREDITED INVESTOR" (WITHIN THE MEANING OF RULE 501 (A)(1), (2), (3) or (7) UNDER THE SECURITIES ACT) THAT IS ACQUIRING THE NOTE FOR ITS OWN ACCOUNT, OR FOR THE ACCOUNT OF SUCH AN INSTITUTIONAL "ACCREDITED INVESTOR," IN EACH CASE IN A MINIMUM PRINCIPAL AMOUNT OF THE NOTES OF US$250,000 AND MULTIPLES OF US$1,000 IN EXCESS THEREOF FOR INVESTMENT PURPOSES ONLY AND NOT WITH A VIEW TO, OR FOR OFFER OR RESALE IN CONNECTION WITH, ANY DISTRIBUTION IN VIOLATION OF THE SECURITIES ACT, (C) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (D) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), (E) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT OR (F) PURSUANT TO ANOTHER AVAILABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT, SUBJECT TO THE COMPANY'S RIGHT PRIOR TO ANY SUCH OFFER, SALE OR TRANSFER PURSUANT TO CLAUSES (B), (D) OR (F) TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL, CERTIFICATION AND/OR OTHER INFORMATION SATISFACTORY TO THE COMPANY, AND IN EACH OF THE FOREGOING CASES, A CERTIFICATE OF TRANSFER IN THE FORM APPEARING ON THE OTHER SIDE OF THIS NOTE IS COMPLETED AND DELIVERED BY THE TRANSFEROR TO THE TRUSTEE AND, IN EACH OF THE FOREGOING CASES, NOT IN VIOLATION OF ANY APPLICABLE STATE SECURITIES LAWS. THIS LEGEND WILL BE REMOVED UPON THE REQUEST OF THE HOLDER AFTER THE RESALE RESTRICTION TERMINATION DATE. THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS NOTE FROM IT OF THE TRANSFER RESTRICTIONS REFERRED TO IN THIS PARAGRAPH.

IF REQUESTED BY THE COMPANY OR A DEALER, THE PURCHASER AGREES TO PROVIDE THE INFORMATION NECESSARY TO DETERMINE WHETHER THE TRANSFER OF THIS NOTE IS PERMISSIBLE UNDER THE SECURITIES ACT. THIS NOTE AND RELATED DOCUMENTATION MAY BE AMENDED OR SUPPLEMENTED FROM TIME TO TIME TO MODIFY THE RESTRICTIONS ON AND PROCEDURES FOR RESALES AND OTHER TRANSFERS OF THIS NOTE TO REFLECT ANY CHANGE IN APPLICABLE LAW OR REGULATION (OR THE INTERPRETATION THEREOF) OR IN PRACTICES RELATING TO THE RESALES OR TRANSFERS OF RESTRICTED SECURITIES GENERALLY. BY THE

ACCEPTANCE OF THIS NOTE, THE HOLDER HEREOF SHALL BE DEEMED TO HAVE AGREED TO ANY SUCH AMENDMENT OR SUPPLEMENT.

[FOR THE PURPOSES OF APPLYING THE ORIGINAL ISSUE DISCOUNT RULES UNDER THE INTERNAL REVENUE CODE OF 1986, AS AMENDED, (1) THE ISSUE DATE OF THIS NOTE IS ; (2) THE ISSUE PRICE OF THIS NOTE IS ; (3) THE YIELD TO MATURITY IS % (COMPOUNDED SEMIANNUALLY); AND (4) THIS NOTE IS BEING ISSUED WITH ORIGINAL ISSUE DISCOUNT IN THE AMOUNT OF [U.S.$] PER U.S.$1,000 PRINCIPAL AMOUNT.]

IN CONNECTION WITH ANY TRANSFER, THE HOLDER WILL DELIVER TO THE REGISTRAR AND TRANSFER AGENT SUCH CERTIFICATES AND OTHER INFORMATION AS SUCH TRANSFER AGENT MAY REASONABLY REQUIRE TO CONFIRM THAT THE TRANSFER COMPLIES WITH THE FOREGOING RESTRICTIONS."

Each purchaser of Certificated Securities will be required to deliver to the Company and the Registrar an investment representation letter substantially in the form prescribed in the Indenture. The Certificated Securities in definitive form will be subject to the transfer restrictions set forth in the above legend, such letter and in the Indenture. Inquiries concerning transfers of Notes should be made to any Dealer.

Sales outside the United States

Regulation S prohibits purchasers of the Notes under Regulation S from offering, selling or delivering the Notes within the United States or to or for the account or benefit of U.S. persons until the expiration of the period ending 40 days after the later of the commencement of the offering of the Notes and the date the Notes were originally issued (the "Distribution Compliance Period").

Each purchaser of the Notes outside the United States pursuant to Regulation S by accepting delivery of this Offering Memorandum and the Notes will be deemed to have represented, agreed and acknowledged that it is, or at the time Notes are purchased will be, the beneficial owner of such Notes and (a) it is located outside the United States and is not a U.S. person (as defined under Regulation S and the Internal Revenue Code) and (b) it is not an affiliate of the Company or a person acting on behalf of such an affiliate.

Each purchaser of the Notes outside the United States pursuant to Regulation S and each subsequent purchaser of such Notes in resales prior to the expiration of the Distribution Compliance Period by accepting delivery of this Offering Memorandum and the Notes, will be deemed to have represented, agreed and acknowledged that:

a. It is, or at the time the Notes are purchased will be, the beneficial owner of such Notes and (A) it is not a U.S. person and it is located outside the United States (within the meaning of Regulation S) and (B) it is not an affiliate of the Company or a person acting on behalf of such an affiliate.

b. It understands that such Notes have not been and will not be registered under the Securities Act and that, prior to the expiration of the Distribution Compliance Period, it will not offer, sell, pledge or otherwise transfer such Notes except (A) in accordance with Rule 144A under the Securities Act to a person that it and any person acting on its behalf reasonably believe is a QIB purchasing for its own account or the account of a QIB or (B) in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S, in each case in accordance with any applicable securities laws of any State of the United States.

c. The Company, the Registrar, the Dealers and their affiliates, and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations and agreements and, if any such acknowledgments, representations or agreements deemed to have been made by virtue of its purchase of the Notes are no longer accurate, it agrees to promptly notify us.

d. It understands that Registered Notes offered in reliance on Regulation S will be represented by an Unrestricted Global Security, which will, unless otherwise agreed by us in accordance with applicable law, bear a legend substantially to the following effect:

"THIS NOTE (OR ITS PREDECESSOR) HAS NOT BEEN AND WILL NOT BE REGISTERED UNDER, AND WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER, THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") AND APPLICABLE SECURITIES LAWS OF THE STATES AND OTHER JURISDICTIONS OF THE UNITED STATES, AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. TERMS USED HEREIN HAVE THE MEANINGS GIVEN THEM IN REGULATION S UNDER THE SECURITIES ACT."

Bearer Notes will be issued in accordance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(D) for purposes of Section 4701 of the Code (the "D Rules"), or in accordance with rules in substantially the same form as United States Treasury Regulations Section 1.163-5(c)(2)(i)(C) for purposes of Section 4701 of the Code (the "C Rules") or not in accordance with the D Rules or the C Rules, as specified in the applicable Pricing Supplement.

In respect of Notes issued in accordance with the D Rules, each purchaser has represented and agreed that:

a. except to the extent permitted under the D Rules, (x) it has not offered or sold, and during the restricted period will not offer or sell, Notes to a person who is within the United States or its possessions or to a United States person, and (y) such purchaser has not delivered and will not deliver within the United States or its possessions definitive Notes that are sold during the restricted period;

b. it has and throughout the restricted period will have in effect procedures reasonably designed to ensure that its employees or agents who are directly engaged in selling Notes are aware that such Notes may not be offered or sold during the restricted period to a person who is within n the United States or its possessions or to a Unites States person, except as permitted by the D Rules;

c. if such purchaser is a United States person, it has represented that it is acquiring the Notes for purposes of resale in connection with their original issuance and if such purchaser retains Notes for its own account, it will only do so in accordance with the requirements of the D Rules;

d. with respect to each affiliate that acquires Notes from such purchaser for the purposes of offering or selling such Notes during the restricted period, such purchaser either (x) repeats and confirms the agreements contained in sub-clauses (i), (ii) and (iii) on such affiliate's behalf or (y) agrees that it will obtain from such affiliate for the benefit of the Issuer the agreements contained in sub-causes (i), (ii) and (iii); and

e. such purchaser will obtain for the benefit of the Company the representations and agreements contained in sub-clauses (i), (ii), (iii) and (iv) from any person other than its affiliate with whom it enters into a written contract, as defined in the D Rules, for the offer and sale during the restricted period of the Note.

Terms used in the above paragraph have the meanings given to them by the U.S. Internal Revenue Code of 1986, as amended, and regulations thereunder, including the D Rules. Notes issued pursuant to the D Rules and any Receipts, Coupons or Talons appertaining thereto will bear the following legend:

"ANY UNITED STATES PERSON WHO HOLDS THIS OBLIGATION WILL BE SUBJECT TO LIMITATIONS UNDER THE UNITED STATES INCOME TAX LAWS, INCLUDING THE LIMITATIONS PROVIDED IN SECTIONS 165(j) AND 1287(a) OF THE INTERNAL REVENUE CODE."

In respect of Bearer Notes issued in accordance with the C Rules, Notes must be issued and delivered outside the United States and its possessions in connection with their original issuance. Each purchaser has represented and agreed that, in connection with the original issuance of Notes, it has not offered, sold or delivered and will not offer, sell or deliver, directly or indirectly, Notes issued in accordance with the C Rules within the United States or its possessions and it has not communicated, and will not communicate, directly or indirectly, with a prospective purchaser if such purchaser is within the United States or its possessions and will not otherwise involve its U.S. office in the offer or sale of Notes. Terms used in this paragraph have the meaning given to them by the U.S. Internal Revenue Code of 1986, as amended, and regulations thereunder, including the C Rules.

Prior to the expiration of the Distribution Compliance Period, before any interest in the Temporary Global Note or Permanent Global Note may be offered, sold, pledged or otherwise transferred to a person who takes delivery in the form of an interest in such Notes, it will be required to provide the Registrar with a written certification (in the form provided in the Indenture) as to compliance with the applicable securities laws.

General

Delivery of the Notes may be made against payment therefor on or about a date which will occur more than two business days after the date of pricing of the Notes which date may be specified in the Pricing Supplement. Pursuant to Rule 15c6-1 under the Exchange Act, trades in the secondary market generally are required to settle in two business days, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade Notes on the date of pricing or the next succeeding business day will be required, by virtue of the fact that the Notes may initially settle on or about a date which will occur more than two business days after the date of pricing of the Notes to specify an alternate settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of Notes who wish to trade Notes on the date of pricing or the next succeeding business day should consult their own advisor.

UNITED STATES BENEFIT PLAN INVESTOR CONSIDERATIONS

The following is a summary of certain considerations associated with the purchase of the Notes by employee benefit plans that are subject to Title I of the U.S. Employee Retirement Income Security Act of 1974, as amended ("ERISA"), plans, individual retirement accounts ("IRAs") and other arrangements that are subject to Section 4975 of the Internal Revenue Code or provisions under any other federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of ERISA or the Internal Revenue Code (collectively, "Similar Laws"), and entities whose underlying assets are considered to include "plan assets" (within the meaning of 29 C.F.R. Section 2510.3-101 (as modified by Section 3(42) of ERISA)) of any such plan, account or arrangement (collectively, "Plans").

General Fiduciary Matters

ERISA and the Internal Revenue Code impose certain duties on Plans subject to Title I of ERISA or Section 4975 of the Internal Revenue Code (an "ERISA Plan") and on persons who are fiduciaries with respect to ERISA Plans and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Internal Revenue Code, any person who exercises any discretionary authority or control over the administration of such an ERISA Plan or the management or disposition of the assets of such an ERISA Plan, or who renders investment advice for a fee or other compensation to such an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan.

In considering an investment in the Notes with a portion of the assets of any Plan, a fiduciary should consult with its counsel in order to determine the suitability of the Notes for such Plan, including whether the investment is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Internal Revenue Code or any Similar Law and the need for, and the availability, if necessary, of any exemptive relief under any such laws or regulations. In addition, a fiduciary of a Plan should consult with its counsel in order to determine if the investment satisfies the fiduciary's duties to the Plan including, without limitation, the prudence, diversification, delegation of control and prohibited transaction provisions of ERISA, the Internal Revenue Code and any other applicable Similar Laws.

Each Plan should consider the fact that none of us, the Arrangers, any of the Dealers or any of our or their respective affiliates (the "Transaction Parties") is acting, or will act, as a fiduciary to any Plan with respect to the decision to purchase or hold the Notes. The Transaction Parties are not undertaking to provide impartial investment advice or advice based on any particular investment need, or to give advice in a fiduciary capacity, with respect to the decision to purchase or hold the Notes. All communications, correspondence and materials from the Transaction Parties with respect to the Notes are intended to be general in nature and are not directed at any specific purchaser of the Notes, and do not constitute advice regarding the advisability of investment in the Notes for any specific purchaser. The decision to purchase and hold the Notes solely by each prospective Plan purchaser on an arm's length basis.

Prohibited Transaction Issues

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit ERISA Plans from engaging in specified transactions involving plan assets with persons or entities who are "parties in interest," within the meaning of ERISA, or "disqualified persons," within the meaning of Section 4975 of the Internal Revenue Code, unless an exemption is available. A party in interest or disqualified person who engaged in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the

ERISA Plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Internal Revenue Code. The acquisition and/or holding of Notes by an ERISA Plan with respect to which a Transaction Party, an Arranger or the Trustee is considered a party in interest or disqualified person may constitute or result in a direct or indirect prohibited transaction under Section 406 of ERISA and/or Section 4975 of the Internal Revenue Code, unless the investment is acquired and is held in accordance with an applicable statutory, class or individual prohibited transaction exemption. In this regard, certain exemptions from the prohibited transaction rules could be applicable to the purchase and holding of Notes by an ERISA Plan, depending on the type and circumstances of the fiduciary making the decision to acquire such Notes and the relationship of the party in interest or disqualified person to the ERISA Plan. Included among these exemptions are Section 408(b)(17) of ERISA, Section 4975(d)(20) of the Internal Revenue Code or Prohibited Transaction Class Exemption ("PTCE"), 84- 14 respecting transactions determined by independent qualified professional asset managers, PTCE 90-1 respecting insurance company pooled separate accounts, PTCE 91-38 respecting bank collective investment funds, PTCE 95- 60 respecting life insurance company general accounts and PTCE 96- 23 respecting transactions determined by in-house asset managers (collectively, the "Class Exemptions"). However, there can be no assurance that all of the conditions of any of these statutory or Class Exemptions or any other exemption will be available with respect to any particular transaction involving the Notes.

Because of the foregoing, the notes should not be purchased or held by any person investing "plan assets" of any Plan, unless such purchase and holding (i) are entitled to exemption relief from the prohibited transaction provisions of ERISA and the Internal Revenue Code and are otherwise permissible under all applicable Similar Laws or (ii) would not otherwise constitute a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Internal Revenue Code or any violation of applicable Similar Laws.

The foregoing discussion is general in nature and is not intended to be all inclusive. Due to the complexity of these rules and the penalties that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries, or other persons considering purchasing the Notes on behalf of, or with the assets of, any Plan, consult with their counsel regarding the potential applicability of ERISA, Section 4975 of the Internal Revenue Code and any Similar Laws to such investment and whether an exemption would be applicable to the purchase and holding of the Notes. The sale of a Note is in no respect a representation by any Transaction Party or any of their respective affiliates or representatives that such an investment meets all relevant legal requirements with respect to investments by any such Plan or that such investment is appropriate for any such Plan.

Representation

Accordingly, by acceptance of a Note, each purchaser and subsequent transferee thereof will be deemed to have represented and warranted that either (i) no portion of the assets used by such purchaser or transferee to acquire or hold the notes or an interest therein constitutes assets of any Plan or (ii) the purchase and holding of the notes or an interest therein by such purchaser or transferee will not constitute a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Internal Revenue Code or a similar violation under any applicable Similar Laws.

None of the Transaction Parties or any other party to the transactions contemplated by this offering memorandum or any of their respective affiliates is acting, or will act, as a fiduciary to any Plan with respect to the decision to purchase or hold the Notes or is undertaking to provide impartial investment advice or give advice in a fiduciary capacity with respect to the decision to purchase or hold the Notes.

LEGAL MATTERS

Certain legal matters with respect to the Notes will be passed upon for us by Latham & Watkins LLP as to matters of New York law and U.S. federal securities law and by UMBRA Partnership as to matters of Indonesian law. Certain legal matters with respect to the Notes will be passed upon for the Arrangers and Dealers by Allen & Overy LLP as to matters of New York law and U.S. federal securities law and by Ginting & Reksodiputro in association with Allen & Overy LLP as to matters of Indonesian law.

INDEPENDENT PUBLIC ACCOUNTANTS

Our consolidated financial statements as of December 31, 2018, 2017 and 2016 and for the years then ended have been audited and reviewed, respectively, by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with Standards on Auditing established by the IICPA, as stated in their audit report appearing elsewhere in this Offering Memorandum.

Our unaudited interim consolidated financial statements as of March 31, 2019 and for the three-month periods ended March 31, 2019 and 2018 have been reviewed by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with SRE 2410, established by the IICPA, as stated in their review report appearing elsewhere in this Offering Memorandum (presented combined with the audit report mentioned above). A review conducted in accordance with SRE 2410 established by the IICPA is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the IICPA, and as stated in their review report appearing in this Offering Memorandum (presented combined with the audit report mentioned above), KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountant, did not audit and do not express any opinion on such unaudited interim consolidated financial statements included elsewhere in this Offering Memorandum.

ENERGY INDUSTRY CONSULTANT

The information contained in the section "Industry Overview" in this Offering Memorandum, including all statistics and data therein, was prepared by Wood Mackenzie, independent energy industry consultants and experts in the energy industry, in the Wood Mackenzie Report. Wood Mackenzie has given and not withdrawn its written consent to the issue of this Offering Memorandum with the inclusion herein of their name and all references thereto and to the inclusion of the "Industry Overview" section in this Offering Memorandum, in the form and context in which it appears, and to act in such capacity in relation thereto. The "Industry Overview" section does not include all of the information that may be important for an investment decision.

SUMMARY OF CERTAIN SIGNIFICANT DIFFERENCES BETWEEN IFAS AND U.S. GAAP

Our consolidated financial statements included elsewhere in this Offering Memorandum have been prepared and presented in accordance with IFAS. Significant differences exist between IFAS and U.S. GAAP, which might be material to the consolidated financial statements herein. The matters described below should not be expected to reveal all differences between IFAS and U.S. GAAP that are relevant to us.

Management has made no attempt to quantify the impact of those differences, nor has any attempt been made to identify all disclosure, presentation, or classification differences that would affect the manner in which transactions or events are presented in the consolidated financial statements. Had any such quantification or identification been undertaken by management, other potential significant accounting and disclosure differences may have come to its attention which are not summarized below. Accordingly, it should not be construed that the following summary of certain significant differences between IFAS and U.S. GAAP is complete.

Regulatory bodies that promulgate IFAS and U.S. GAAP have significant ongoing projects that could affect future comparisons such as this one. Further, no attempt has been made to identify future differences between IFAS and U.S. GAAP as a result of prescribed changes in accounting standards and regulations. Finally, no attempt has been made to identify all future differences between IFAS and U.S. GAAP that may affect the consolidated financial statements as a result of transactions or events that may occur in future.

Management believes that the application of U.S. GAAP to the consolidated financial statements could have a material and significant impact upon the consolidated financial statements reported under IFAS. In making an investment decision, investors must rely upon their own examination of us, terms of the offering, and the consolidated financial statements. Potential investors should consult their own professional advisors for an understanding of the differences between IFAS and U.S. GAAP, and how those differences might affect the consolidated financial statements included herein.

Interim Financial Reporting

Under IFAS, each interim period is viewed as a discrete reporting period. A cost that does not meet the definition of an asset at the end of an interim period is not deferred, and a liability recognized at an interim reporting date must represent an existing obligation. Under U.S. GAAP, each interim period is viewed as an integral part of an annual period. As a result, certain costs that benefit more than one interim period may be allocated among those periods, resulting in deferral or accrual of certain costs.

Consolidation, Joint Venture Accounting, and Equity-Method Investment

IFAS provides a single control model for all entities, including structured entities. An investor controls an investee when it is exposed or has rights to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Potential voting rights and the notion of “de facto control” are considered. U.S. GAAP provides for primarily two consolidation models (i.e. variable interest model and voting model). The variable interest model evaluates control based on determining which party has power and benefits, while the voting model evaluates control based on existing voting rights. All entities are first evaluated as potential variable interest entities (“VIEs”). If an entity is not a VIE, it is evaluated for control pursuant to the voting model. Potential voting rights are generally not included in either evaluation and the notion of “de factor control” is not considered.

Under IFAS, when relevant, preparation of consolidated financial statements is required in all cases, and that the "parent-only" financial statements (which are not required part of consolidated financial statements), if presented, can only be presented as supplementary information to the consolidated financial statements. Under U.S. GAAP, when relevant, preparation of consolidated financial statements is required, although certain industry-specific exceptions exist (e.g. investment companies).

Under IFAS, the financial statements of a parent and its consolidated subsidiaries are prepared as of the same date. When the parent and the subsidiary have different reporting period end dates, the subsidiary prepares (for consolidation purposes) additional financial statements as of the same date as those of the parent unless it is impracticable. If it is impracticable, when the difference in the reporting period end dates of the parent and subsidiary is three months or less, the financial statements of the subsidiary may be adjusted to reflect significant transactions and events, and it is not necessary to prepare additional financial statements as of the parent's reporting date. Under U.S. GAAP, the reporting entity and the consolidated entities are permitted to have differences in year-ends of up to three months. The effects of significant events occurring between the reporting dates of the reporting entity and the controlled entities are disclosed in the financial statements.

Under IFAS, uniform accounting policies between parent and subsidiary are required. Under U.S. GAAP, uniform accounting policies between parent and subsidiary are not required.

Under IFAS, transactions that result in decreases in the ownership interest of any subsidiary without a loss of control are accounted for as equity transactions in the consolidated entity (i.e. no gain or loss is recognized). Under U.S. GAAP, transactions that result in decreases in the ownership interest of any subsidiary without a loss of control are accounted for as equity transactions in the consolidated entity only when: (i) the subsidiary is a business or non-profit activity (except in a conveyance of oil and gas mineral rights), or (i) the subsidiary is not a business or non-profit activity, but the substance of the transaction is not addressed directly by other accounting standard under U.S. GAAP.

Under IFAS, for certain transactions that result in a loss of control of a subsidiary, the accounting guidance is generally consistent with U.S. GAAP, except that the related guidance applies to all subsidiaries, including those that are not businesses or non-profit activities and those that involve conveyance of oil and gas mineral rights. In addition, the gain or loss resulting from the loss of control of a subsidiary that does not constitute a business in a transaction involving an associate or a joint venture that is accounted for using the equity method is recognized only to the extent of the unrelated investors' interests in that associate or joint venture. Under U.S. GAAP, for certain transactions that result in a loss of control of a subsidiary, any retained non-controlling investment in the former subsidiary is remeasured to fair value on the date the control is lost, with the gain or loss included in income along with any gain or loss on the ownership interest sold. This accounting is limited only to the following transactions: (i) loss of control of a subsidiary that is a business or non-profit activity (except for a conveyance of oil and gas mineral rights), and (ii) loss of control of a subsidiary that is not a business or non-profit activity if the substance of the transaction is not addressed directly by other accounting standard under U.S. GAAP.

Under IFAS, for transactions that result in a loss of control of a group of assets that meet the definition of a business, any retained non-controlling investment in the former group of assets is remeasured to fair value on the date control is lost, with the gain or loss included in income along with any gain or loss on the ownership interest sold. Under U.S. GAAP, for certain transactions that result in a loss of control of a group of assets that meet the definition of a business or non-profit activity, any retained non-controlling investment in the former group of assets is remeasured to fair value on the date control is lost, with the gain or loss included in income along with any gain or loss on the ownership interest sold. However, this accounting does not apply to: (i) a conveyance of oil and gas mineral rights, and (ii) a transfer of a good or service in a contract with a customer within the scope of Accounting Standard Codification 606, "Revenue from Contracts with Customers" ("ASC 606").

Business Combinations

Under IFAS, non-controlling interest components that are present ownership interests and entitle their holders to a proportionate share of the acquiree's net assets in the event of liquidation may be measured at: (i) fair value, including goodwill, or (ii) the non-controlling interest's proportionate share of the fair value of the acquiree's identifiable net assets, exclusive of goodwill. All other components of non-controlling interest are measured at fair value unless another measurement basis is required by IFRS. The choice is available on a transaction-by-transaction basis. Under U.S. GAAP, non-controlling interest is measured at fair value, including goodwill.

Under IFAS, there is no specific accounting standard that governs the accounting for combination of entities under common control. In practice, entities either follow an approach like U.S. GAAP (i.e. historical cost) as described below or apply the acquisition method (fair value) if there is substance to the transaction (policy election). U.S. GAAP requires that the receiving entity records the net assets at their carrying amounts in the accounts of the transferor (historical cost) in a combination of entities under common control.

Under IFAS, there is no specific accounting standard that governs pushdown accounting, and accordingly, it is unclear whether pushdown accounting is acceptable. Under U.S. GAAP, an acquired entity can choose to apply pushdown accounting in its separate financial statements when an acquirer obtains control of it or later; however, an entity's election to apply pushdown accounting is irrevocable.

Under IFAS, an acquirer recognizes measurement-period adjustments pertained to a business combination on a retrospective basis, whereby the acquirer revises comparative information for any prior periods presented, including revisions for any effects on the prior-period income statement. Under U.S. GAAP, an acquirer recognizes measurement-period adjustments pertained to a business combination during the period in which it determines the amounts, including the effect on earnings of any amounts it would have recorded in previous periods if the accounting had been completed at the acquisition date.

Under IFAS, a business consists of inputs and processes applied to those inputs that have the ability to create outputs. Although businesses usually have outputs, outputs are not required for an integrated set to qualify as a business. The term "substantive process" is not defined in IFAS. An integrated set of activities and assets requires two essential elements (i.e. inputs and processes) applied to those inputs, which together are or will be used to create outputs. However, a business does not have to include all the inputs or processes that the seller used in operating that business if market participants are capable of to produce outputs, for example, by integrating the business with their own inputs and processes. Outputs are defined as the result of inputs and processes applied to those inputs that provide or have the ability to provide a return in the form of dividends, lower costs, or other economic benefits directly to investors or other owners, members, or participants. There is no threshold test under IFAS. Under U.S. GAAP, a business must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs. An output is the result of inputs and processes applied to those inputs that provide goods or services to customers, investment income (such as dividends or interest), or other revenues. That is, the focus is on revenue-generating activities, which more closely aligns the definition with the description of outputs in the new revenue guidance in ASC 606. An entity does not need to evaluate whether any missing elements could be replaced by a market participant. An entity must first evaluate whether substantially all the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. If that threshold is met, the set is not a business and does not require further evaluation. Gross assets acquired should exclude cash and cash equivalents, deferred tax assets, and any goodwill that would be created in a business combination from the recognition of deferred tax liabilities.

Inventory

Under IFAS, the use of the last-in-first-out ("LIFO") method in determining the cost of inventory is not permitted and that same cost formula must be applied to all inventories similar in nature or use to the entity. Under U.S. GAAP, the use of the LIFO method in determining the cost of inventory is permitted; however, a consistent cost formula for all inventories similar in nature is not explicitly required.

Under IFAS, inventory is carried at the lower of cost or net realizable value, whereby net realizable value is defined as the estimated selling price less the estimated costs of completion and the estimated costs necessary to make the sale. Under U.S. GAAP, only inventory other than that accounted for under the LIFO or retail inventory method ("RIM") is carried at the lower of cost and net realizable value.

Under IFAS, previously recognized impairment losses on inventories are reversed up to the amount of the original impairment loss when the reasons for the impairment no longer exist. Under U.S. GAAP, any write-down of inventory below cost creates a new cost basis that subsequently cannot be reversed.

Under IFAS, permanent markdowns affect the average gross margin used in applying the RIM. Reduction of the carrying cost of inventory to below the lower of cost and net realizable value is not allowed. Under U.S. GAAP, permanent markdowns do not affect the gross margins used in applying the RIM; rather, such markdowns reduce the carrying cost of inventory to net realizable value, less an allowance for an approximately normal profit margin, which may be less than both original cost and net realizable value.

Land Rights

In Indonesia, except for ownership rights granted to individuals, the title to land rests with the government. Land use is accomplished through land rights whereby the holder of the rights enjoys the full use of the land for a stated period, subject to extensions. Under IFAS, land rights are not depreciated unless management believes that it is highly unlikely that extensions of the land rights will not be granted by the government. The predominant practice is to capitalize (and not to amortize) the costs of acquired land rights, as entities generally believe that extensions of the land rights will be granted by the government. Other expenses associated with the acquisition of government permits to use the land, including legal fees, area survey and re-measurement fees, notary fees, and taxes, are capitalized and amortized over the period of the right to use the land. Under U.S. GAAP, the costs and other expenses associated with the acquisition of land rights are capitalized and amortized over the period of the right to use the land.

Long-Lived Assets

Under IFAS, revaluation of long-lived assets is a permitted accounting policy election for an entire class of assets, requiring revaluation to fair value on a regular basis. Under U.S. GAAP, revaluation of long-lived assets is not permitted.

Under IFAS, component depreciation of long-lived assets is required if components of an asset have differing patterns of benefit. Under U.S. GAAP, component depreciation of long-lived assets is permitted, but it is not common.

Under IFAS, eligible borrowing costs that are capitalized as part of a qualifying long-lived asset include exchange rate differences from foreign currency borrowings to the extent that they are regarded

as an adjustment to interest costs. For borrowings associated with a specific qualifying asset, actual borrowing costs are capitalized offset by investment income earned on those borrowings. Under U.S. GAAP, eligible borrowing costs do not include exchange rate differences. Interest earned on the investment of borrowed funds generally cannot offset interest costs incurred during the period. For borrowings associated with a specific qualifying asset, borrowing costs equal to the weighted-average accumulated expenditures times the borrowing rate are capitalized.

Under IFAS, costs that represent a replacement of a previously identified component of an asset are capitalized if future economic benefits are probable and the costs can be reliably measured; otherwise, these costs are expensed as incurred. Under U.S. GAAP, multiple accounting models have evolved in practice for entities in the airline industry, including expense costs as incurred, capitalize costs and amortize through the date of the next overhaul, or follow the built-in overhaul approach (i.e., an approach with certain similarities to composite depreciation).

Under IFAS, investment property is separately defined as property held to earn rent or for capital appreciation (or both) and may include property held by lessees under a finance or operating lease. Investment property may be accounted for on a historical cost basis or on a fair value basis as an accounting policy election. Capitalized operating leases classified as investment property must be accounted for using the fair value model. Under U.S. GAAP, investment property is not separately defined and, therefore, is accounted for as held and used or held for sale.

Intangible Assets

Under IFAS, development costs are capitalized when technical and economic feasibility of a project can be demonstrated in accordance with specific criteria, including demonstrating technical feasibility, intent to complete the asset, and ability to sell the asset in the future. Although application of these principles may be largely consistent with those under U.S. GAAP, there is no separate guidance addressing computer software development costs. Under U.S. GAAP, development costs are expensed as incurred unless addressed by guidance in another accounting standard. Development costs related to computer software developed for external use are capitalized once technological feasibility is established in accordance with specific criteria. In the case of software developed for internal use, only those costs incurred during the application development stage may be capitalized.

Under IFAS, advertising and promotional costs are expensed as incurred. A prepayment may be recognized as an asset only when payment for the goods or services is made in advance of the entity having access to the goods or receiving the services. Under U.S. GAAP, advertising and promotional costs are either expensed as incurred or expensed when the advertising takes place for the first time (policy choice).

Under IFAS, revaluation to fair value of intangible assets other than goodwill is a permitted accounting policy election for a class of intangible assets. Because revaluation requires reference to an active market for the specific type of intangible, this is relatively uncommon in practice. Under U.S. GAAP, revaluation of intangible assets is not permitted.

Impairment of Long-Lived Assets, Goodwill, and Intangible Assets

Under IFAS, the one-step approach requires that an impairment loss calculation of long-lived assets, goodwill, or intangible assets be performed if impairment indicators exist. Under U.S. GAAP, the two-step approach requires that a recoverability test be performed first (the carrying amount of the asset is compared with the sum of future undiscounted cash flows using entity-specific assumptions generated through use and eventual disposition). If it is determined that the asset is not recoverable, an impairment loss calculation is required.

Under IFAS, an impairment loss is the amount by which the carrying amount of the asset exceeds its recoverable amount, which is the higher of: (i) fair value less costs to sell, and (ii) value in use (the present value of future cash flows in use, including disposal value). Under U.S. GAAP, an impairment loss is the amount by which the carrying amount of the asset exceeds its fair value using market participant assumptions.

Under IFAS, in assessing the impairment of goodwill, goodwill is allocated to a cash-generating unit ("CGU") or group of CGUs that represents the lowest level within the entity at which the goodwill is monitored for internal management purposes and cannot be larger than an operating segment (before aggregation). Further, the qualitative assessment is not permitted. The one-step approach requires that an impairment test be done at the CGU level by comparing the CGU's carrying amount (including goodwill) with its recoverable amount. The impairment loss on the CGU (the amount by which the CGU's carrying amount (including goodwill) exceeds its recoverable amount) is allocated first to reduce goodwill to zero, then, subject to certain limitations, the carrying amount of other assets in the CGU are reduced pro rata, based on the carrying amount of each asset. Under U.S. GAAP, in assessing the impairment of goodwill, goodwill is assigned to a reporting unit, which is defined as an operating segment or one level below an operating segment (component). Further, an entity has the option to qualitatively assess whether it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount. The entity performs a recoverability test under the two-step approach first at the reporting unit level (the carrying amount of the reporting unit is compared with the reporting unit's fair value). If the carrying amount of the reporting unit exceeds its fair value, the entity performs impairment testing. The impairment loss is determined as the amount by which the carrying amount of goodwill exceeds the implied fair value of the goodwill within its reporting unit.

Under IFAS, in assessing the impairment of indefinite-lived intangibles, qualitative assessment is not permitted. The one-step approach requires that an impairment test be done at the CGU level by comparing the CGU's carrying amount (including goodwill) with its recoverable amount. If the indefinite-lived intangible asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, then the indefinite-lived intangible asset should be tested for impairment as part of the CGU to which it belongs unless certain conditions are met. Under U.S. GAAP, in determining the impairment of indefinite-lived intangibles, an entity has the option to qualitatively assess whether it is more-likely-than-not that an indefinite-lived intangible asset is impaired. If a quantitative test is performed, the quantitative impairment test for an indefinite-lived intangible asset requires a comparison of the fair value of the asset with its carrying amount. If the carrying amount of an intangible asset exceeds its fair value, the entity should recognize an impairment loss in an amount equal to that excess. Indefinite-lived intangible assets separately recognized should be assessed for impairment individually unless they operate in concert with other indefinite-lived intangible assets as a single asset (i.e. the indefinite-lived intangible assets are essentially inseparable). Indefinite-lived intangible assets may not be combined with other assets (e.g. finite-lived intangible assets or goodwill) for purposes of an impairment test.

Under IFAS, reversal of impairment loss previously recognized is prohibited for goodwill. Other assets must be reviewed at the end of each reporting period for reversal indicators. If appropriate, loss should be reversed up to the newly estimated recoverable amount, not to exceed the initial carrying amount adjusted for depreciation. Under U.S. GAAP, reversal of impairment loss previously recognized is prohibited for all assets to be held and used.

Financial Instruments

Under IFAS, classification of certain instruments with characteristics of both debt and equity is largely based on the contractual obligation to deliver cash, assets, or an entity's own shares. Economic compulsion does not constitute a contractual obligation. Contracts that are indexed to, and potentially settled in, an entity's own stock are classified as equity if settled only by delivering a fixed number of

shares for a fixed amount of cash. Compound (hybrid) financial instruments are required to be split into a debt and equity component or, if applicable, a derivative component. The derivative component is accounted for using fair value accounting. Under U.S. GAAP, certain instruments with characteristics of both debt and equity that must be classified as liabilities are specifically identified. Certain other contracts that are indexed to, and potentially settled in, an entity's own stock may be classified as equity if they either: (i) require physical settlement or net-share settlement, or (ii) give the issuer a choice of net-cash settlement or settlement in its own shares. Compound (hybrid) financial instruments (e.g. convertible bonds) are not split into debt and equity components unless certain specific requirements are met, but they may be bifurcated into debt and derivative components, with the derivative component accounted for using fair value accounting.

Under IFAS, regardless of an instrument's legal form, its classification and measurement depend on its contractual cash flow ("CCF") characteristics and the business model under which it is managed. The assessment of the CCF determines whether the contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding. Financial assets that pass the cash flow characteristics test are subsequently measured at: (i) amortized cost, (ii) fair value, with changes in fair value recognized in other comprehensive income ("FV-OCI"), or (iii) fair value, with changes in fair value recognized in net income ("FV-NI"), based on the entity's business model for managing them unless the fair value option is elected. Financial assets that fail the cash flow characteristics test are subsequently measured at FV-NI. Under U.S. GAAP, classification and measurement depend largely on the legal form of the instrument (i.e. whether the financial asset represents a security or a loan) and management's intent for the instrument. At acquisition, debt instruments that meet the definition of a security are classified in one of three categories and subsequently measured at: (i) amortized cost (for held-to-maturity ("HTM") securities), (ii) FV-NI (for trading securities), or (iii) FV-OCI (for available-for-sale ("AFS") securities). Unless the fair value option is elected, loans and receivables are classified as either: (i) held for investment, and then measured at amortized cost, or (ii) held for sale, and then measured at the lower of cost or fair value.

Under IFAS, equity investments are measured at FV-NI. An irrevocable FV-OCI election is available for non-derivative equity investments that are not held for trading. If the FV-OCI election is made, gains or losses recognized in other comprehensive income are not recycled (i.e. reclassified to earnings) upon derecognition of those investments. Under U.S. GAAP, equity investments are measured at FV-NI. A measurement alternative is available for equity investments that do not have readily determinable fair values and do not qualify for the net asset value practical expedient. These investments may be measured at cost, less any impairment, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer.

IFAS requires the original effective interest rate to be used throughout the life of the financial instrument, except for certain reclassified financial assets. When estimated cash flows change, an entity follows an approach that is analogous to the catch-up method under U.S. GAAP. US GAAP requires a catch-up approach, retrospective method, or prospective method of calculating the interest for amortized cost-based assets (when estimated cash flows are used), depending on the type of instrument.

Under IFAS, the definition of a derivative does not include a requirement that a notional amount be indicated nor is net settlement a requirement. Certain of the scope exceptions under IFAS differ from those under US GAAP. Under U.S. GAAP, to meet the definition of a derivative, an instrument must: (i) have one or more underlying, and, one or more notional amounts or payment provisions or both, (ii) require no initial net investment, as defined, and (iii) be able to be settled net, as defined. Certain scope exceptions exist for instruments that would otherwise meet these criteria.

Under IFAS, hedging of risk components of both financial and non-financial items is allowed, provided that the risk component is separately identifiable and reliably measurable. To qualify for hedge accounting, there must be an economic relationship between the hedged item and the hedging instrument, the value changes resulting from that economic relationship cannot be dominated by credit risk, and the hedge ratio should generally be the same as the ratio management uses to hedge the quantity of the hedged item. Only prospective assessment of effectiveness is required at each reporting period. The shortcut method for interest rate swaps hedging recognized debt is not permitted. The assessment and measurement of hedge effectiveness for a fair value hedge of the benchmark interest rate component of a fixed rate debt instrument generally considers only the change in fair value of the designated benchmark cash flows. A hedging instrument's time value and foreign currency basis spread can be excluded from the effectiveness assessment. The change in fair value of any excluded components is deferred in accumulated other comprehensive income and reclassified based on the nature of the hedged item (i.e. transaction-related or time-period related). Under U.S. GAAP, the risk components of financial instruments that may be hedged are specifically defined by the literature, with no additional flexibility. Except for foreign currency risk, a risk component associated with a non-financial item may not be hedged. To qualify for hedge accounting the relationship must be "highly effective". Prospective and retrospective assessment of hedge effectiveness is required on a periodic basis (at least quarterly). The shortcut method for interest rate swaps hedging recognized debt instruments is permitted. The long-haul method of assessing and measuring hedge effectiveness for a fair value hedge of the benchmark interest rate component of a fixed rate debt instrument requires that all CCFs be considered in calculating the change in the hedged item's fair value even though only a component of the contractual coupon payment is the designated hedged item. A hedging instrument's time value can be excluded from the effectiveness assessment. The change in fair value of any excluded time value is recognized currently in earnings.

Under IFAS, derecognition of financial assets is based on a mixed model that considers transfer of risks and rewards and control. Transfer of control is considered only when the transfer of risks and rewards assessment is not conclusive. If the transferor has neither retained nor transferred substantially all the risks and rewards, there is then an evaluation of the transfer of control. Control is considered to be surrendered if the transferee has the practical ability to unilaterally sell the transferred asset to a third party without restrictions. There is no legal isolation test. The derecognition criteria may be applied to a portion of a financial asset if the cash flows are specifically identified or represent a pro rata share of the financial asset or a pro rata share of specifically identified cash flows. Under U.S. GAAP, derecognition of financial assets (i.e. sales treatment) occurs when effective control over the financial asset has been surrendered whereby: (i) the transferred financial assets are legally isolated from the transferor, (ii) each transferee (or, if the transferee is a securitization entity or an entity whose sole purpose is to facilitate an asset-backed financing, each holder of its beneficial interests) has the right to pledge or exchange the transferred financial assets (or beneficial interests), and (iii) the transferor does not maintain effective control over the transferred financial assets or beneficial interests (e.g. through a call option or repurchase agreement). The derecognition criteria may be applied to a portion of a financial asset only if it mirrors the characteristics of the original entire financial asset.

Under IFAS, day one gains and losses on financial instruments are recognized only when their fair value is evidenced by a quoted price in an active market for an identical asset or liability (i.e. level 1 input) or based on a valuation technique that uses only data from observable markets. Under U.S. GAAP, entities are not precluded from recognizing day one gains and losses on financial instruments reported at fair value even when all inputs to the measurement model are not observable, including when the fair value measurement is based on a valuation model with significant unobservable inputs (i.e. level 3 measurements).

Under IFAS, there is no practical expedient for estimating fair value using net asset value for certain alternative investments. Under U.S. GAAP, entities are provided a practical expedient to

estimate the fair value of certain alternative investments (e.g. a limited partner interest in a private equity fund) using net asset value or its equivalent.

Foreign Currency

Under IFAS, the functional currency must be maintained. However, local functional currency financial statement amounts not already measured at the current rate at the end of the reporting period (current and prior period) are indexed using a general price index (i.e. restated in terms of the measuring unit current at the date of the statement of financial position with the resultant effects recognized in income), and are then translated to the reporting currency at the current rate. Under U.S. GAAP, local functional currency financial statements are remeasured as if the functional currency was the reporting currency (e.g. United States ("US") dollar in the case of a US parent) with resulting exchange differences recognized in income.

Under IFAS, the method of consolidation is not specified and, as a result, either the "direct" or the "step-by-step" method of consolidation is used. Under the "direct" method, each entity within the consolidated group is directly translated into the functional currency of the ultimate parent and then consolidated into the ultimate parent (i.e. the reporting entity) without regard to any intermediate parent. The choice of consolidation method used could affect the cumulative translation adjustments deferred within equity at intermediate levels, and therefore, the recycling of such exchange rate differences upon disposal of an intermediate foreign operation. Under U.S. GAAP, a "bottom-up" approach is required to reflect the appropriate foreign currency effects and hedges in place. As such, an entity should be consolidated by the enterprise that controls the entity. Therefore, the "step-by-step" method of consolidation is used, whereby each entity is consolidated into its immediate parent until the ultimate parent has consolidated the financial statements of all the entities below it.

Leases

Under IFAS, when the leaseback is an operating leaseback (non-real estate) in a sale-and-leaseback type of lease, gain or loss is recognized immediately, subject to adjustment if the sales price differs from fair value. Under U.S. GAAP, when the leaseback is an operating leaseback (non-real estate) in a sale-and-leaseback type of lease, the seller-lessee recognizes any gain or loss, adjusted for off-market terms, immediately.

Under IFAS, when the leaseback is a capital leaseback in a sale-and-leaseback type of lease, gain or loss is deferred and amortized over the lease term. Under U.S. GAAP, when the leaseback is a capital leaseback in a sale-and-leaseback type of lease, the seller-lessee is presumed to have retained substantially all the remaining use of the leased asset when the leaseback is classified as a capital lease. In such cases, the profit on sale is deferred.

Income Taxes

Under IFAS, tax basis is generally the amount deductible or taxable for tax purposes. The way management intends to settle or recover the carrying amount affects the determination of tax basis. Under U.S. GAAP, tax basis is a question of fact under the tax law. For most assets and liabilities, there is no dispute on this amount; however, when uncertainty exists, it is determined in accordance with Accounting Standard Codification 740-10-25, "Income Taxes".

IFAS requires taxes paid on intercompany profits to be recognized as incurred and requires the recognition of deferred taxes on temporary differences between the tax bases of assets transferred

between entities/tax jurisdictions that remain within the consolidated group. U.S. GAAP requires taxes paid on intercompany profits to be deferred and prohibits the recognition of deferred taxes for the increases in the tax bases due to the intercompany sale or transfer of inventory. The income tax effects of the intercompany sale or transfer of inventory is recognized when the inventory is sold to a party outside of the consolidated group. Entities are required to recognize the income tax effects of intercompany sales and transfers of assets other than inventory in the period in which the transfer occurs.

Under IFAS, there is no specific accounting standard that governs the accounting for uncertain tax positions. Indonesian Statement of Financial Accounting Standards 46, "Income Taxes", indicates that tax assets and liabilities should be measured at the amount expected to be paid based on enacted or substantively enacted tax legislation. Some adopt a "one-step" approach that recognizes all uncertain tax positions at an expected value. Others adopt a "two-step" approach that recognizes only those uncertain tax positions that are considered more-likely-than-not to result in a cash outflow. Practice varies regarding the consideration of detection risk in the analysis. Under U.S. GAAP, a two-step process is required when assessing uncertain tax positions, separating recognition from measurement. A benefit is recognized when it is more-likely-than-not to be sustained based on the technical merits of the position. Detection risk is precluded from being considered in the analysis. The amount of benefit to be recognized is based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. The unit of account for uncertain tax positions is based on the level at which an entity prepares and supports the amounts claimed in the tax return and considers the approach the entity anticipates the taxation authority will take in an examination.

Under IFAS, deferred tax effects arising from the initial recognition of an asset or liability are not recognized when: (i) the amounts did not arise from a business combination, and (ii) upon occurrence, the transaction affects neither accounting nor taxable profit (e.g. acquisition of non-deductible assets). Under U.S. GAAP, there is no exemption for non-recognition of deferred tax effects for certain assets or liabilities.

Under IFAS, deferred tax assets are recognized only to the extent that it is probable (more-likely-than-not) that they will be realized. Under U.S. GAAP, deferred tax assets are recognized in full (except for certain outside basis differences), but the valuation allowance reduces them to the amount that is more-likely-than-not to be realized.

Under IFAS, enacted or "substantively enacted" tax rates as of the date of the statement of financial position must be used in calculating deferred tax asset or liability. Under U.S. GAAP, enacted tax rates as of the date of the statement of financial position must be used in calculating deferred tax asset or liability.

Under IFAS, recognition of deferred tax liabilities from investments in subsidiaries or joint ventures (often referred to as outside basis differences) is not required if the reporting entity has control over the timing of the reversal of the temporary difference, and it is probable (more-likely-than-not) that the difference will not reverse in the foreseeable future. Under U.S. GAAP, recognition of deferred tax liabilities from investments in subsidiaries or joint ventures (often referred to as outside basis differences) is not required for investment in a foreign subsidiary or foreign corporate joint venture that is essentially permanent in duration unless it becomes apparent that the difference will reverse in the foreseeable future.

Provisions and Contingencies

Under IFAS, a loss must be "probable" (in which "probable" is interpreted as "more-likely-than-not") to be recognized. "More-likely-than-not" refers to a probability of greater than 50%. Under

U.S. GAAP, a loss must be "probable" (in which "probable" is interpreted as "likely") to be recognized. While U.S. GAAP does not ascribe a percentage to "probable", it is intended to denote a high likelihood (e.g. 70% or more).

Under IFAS, provisions should be recorded at the estimated amount to settle or transfer the obligation taking into consideration the time value of money. The discount rate to be used should be "a pre-tax rate (or rates) that reflects (or reflect) current market assessments of the time value of money and the risks specific to the liability." Under U.S. GAAP, provisions may be discounted only when the amount of the liability and the timing of the payments are fixed or reliably determinable, or when the obligation is a fair value obligation (e.g. an asset retirement obligation). The discount rate to be used is dependent upon the nature of the provision, and may vary from that used under IFAS. However, when a provision is measured at fair value, the time value of money and the risks specific to the liability should be considered.

Under IFAS, the best estimate of obligation should be accrued. For a large population of items being measured (such a warranty costs), the best estimate is typically expected value, although the midpoint in the range may also be used when any point in a continuous range is as likely as another. The best estimate for a single obligation may be the most likely outcome, although other possible outcomes should still be considered. Under U.S. GAAP, the most likely outcome within the range should be accrued. When no one outcome is more likely than the others, the minimum amount in the range of outcomes should be accrued.

Under IFAS, once management has "demonstrably committed" (i.e. a legal or constructive obligation has been incurred) to a detailed exit plan, the general provisions under Indonesian Statement of Financial Accounting Standards 57, "Provisions, Contingent Liabilities, and Contingent Assets" apply. Costs typically are recognized earlier than under U.S. GAAP because IFAS focuses on the exit plan as a whole rather than the individual cost components of the exit plan. Under U.S. GAAP, once management has committed to a detailed exit plan, each type of cost is examined to determine when recognized. Involuntary employee termination costs under a one-time benefit arrangement are recognized over future service period, or immediately if there is no future service required. Other exit costs are expensed when incurred.

Revenue Recognition

Under IFAS, revenue is defined as the gross inflow of economic benefits during the period arising during the ordinary activities of an entity when those inflows result in increases in equity, other than increases relating to contributions from equity participants. Under this principle, revenue from sale of goods is recognized only when: (i) risks and rewards of ownership have been transferred, (ii) the seller retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold, revenues can be measured reliably, (iv) it is probable that the economic benefits will flow to the seller, and (v) the costs incurred or to be incurred in respect of the transaction can be measured reliably; while revenue from rendering of services may be recognized in accordance with long-term contract accounting whenever revenues, costs, and the stage of completion can be measured reliably and it is probable that economic benefits will flow to the seller. Under U.S. GAAP, ASC 606 governs the accounting for revenue and is broadly applicable to all revenue transactions with customers (with some limited scope exceptions, for example: insurance contracts, financial instruments, leases). ASC 606 also specifies the accounting for costs an entity incurs to obtain and fulfill a contract to provide goods and services to customers and provide a model for the measurement and recognition of gains and losses on the sale of certain non-financial assets, such as property and equipment, including real estate. The core principle of ASC 606 is that an entity will recognize revenue to depict the transfer of promised goods or services to customers at an amount that reflects the consideration the entity expects to be entitled in exchange for those goods or services. It also requires comprehensive disclosures and changes the way entities communicate information in the

notes to the financial statements. The principles in ASC 606 are applied using the following five steps: (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract, (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract, and (v) recognize revenue when (or as) the entity satisfies a performance obligation. ASC 606 requires retrospective adoption either using a "full retrospective" method (applied to all the periods presented) or a "modified retrospective" method (applied only to the most current period presented in the financial statements).

Share-Based Payments

Under IFAS, there is no accounting policy election for forfeitures. Initial accruals of compensation cost are based on the estimated number of instruments for which the requisite service is expected to be rendered. That estimate should be revised if subsequent information indicates that the actual number of instruments expected to vest is likely to differ from previous estimates. Under U.S. GAAP, entities will have to elect whether to account for forfeitures by: (i) recognizing forfeitures of awards as they occur (e.g. when an award does not vest because the employee leaves the entity), or (ii) estimating the number of awards expected to be forfeited and adjusting the estimate when subsequent information indicates that the estimate is likely to change.

Under IFAS, a performance condition is a vesting condition that must be met while the counterparty is rendering service. The period to achieve a performance condition must not extend beyond the end of the service period. If a performance target can be achieved after the employee's requisite service period, it would be accounted for as a non-vesting condition that affects the grant date fair value of the award. Under U.S. GAAP, a performance condition where the performance target affects vesting can be achieved after the employee's requisite service period. Therefore, the period to achieve a performance target can extend beyond the end of the service period.

Under IFAS, the definition of an employee is more general in that it includes individuals who provide services like those rendered by employees. Fair value of the transaction should be based on the fair value of the goods or services received, and only on the fair value of the equity instruments granted in the rare circumstance that the fair value of the goods and services cannot be reliably estimated. Measurement date is the date the entity obtains the goods or the counterparty renders the services. No performance commitment concept exists. Under U.S. GAAP, the definition of an employee focuses primarily on the common law definition of an employee. The fair value of: (i) the goods or services received, or (ii) the equity instruments granted, whichever is more reliably measurable, is used to value the transaction. Measurement date is the earlier of: (i) the date at which a "commitment for performance" by the counterparty is reached, or (ii) the date at which the counterparty's performance is complete.

Under IFAS, compensation cost for awards with graded vesting features must be recognized on an accelerated basis and each individual tranche must be separately measured. Under U.S. GAAP, entities make an accounting policy election to recognize compensation cost for awards containing only service conditions either on a straight-line basis or on an accelerated basis, regardless of whether the fair value of the award is measured based on the award as a whole or for each individual tranche.

Under IFAS, liability classification is required (i.e. no six-month consideration exists like in U.S. GAAP) for equity repurchase features at employee's election. Under U.S. GAAP, liability classification is not required if employee bears risks and rewards of equity ownership for at least six months from the date the shares are issued or vest.

Under IFAS, when there is modification of vesting terms that are improbable of achievement, compensation cost is determined based on the grant date fair value of the award, together with any

incremental fair value at the modification date. The determination of whether the original grant date fair value affects the accounting is based on the ultimate outcome (i.e. whether the original or modified conditions are met) rather than the probability of vesting as of the modification date. Under U.S. GAAP, if an award is modified such that the service or performance condition, which was previously improbable of achievement, is probable of achievement because of the modification, the compensation cost is determined based on the fair value of the modified award at the modification date. Grant date fair value of the original award is not recognized.

Employee Benefits Other Than Share-Based Payments

Under IFAS, the projected unit credit method is required in all cases in computing employee benefits liability for defined benefit plans. Under U.S. GAAP, different methods are required in computing employee benefits liability for defined benefit plans, depending on the characteristics of the plan's benefit formula.

Under IFAS, the concept of an expected return on plan assets does not exist in calculating the expected return on plan assets. Instead, a "net interest" expense/(income) on the net defined benefit liability/(asset) is recognized as a component of defined benefit cost based on the discount rate used to determine the obligation. Under U.S. GAAP, the concept of an expected return on plan assets exists in calculating the expected return on plan assets, which is calculated using the expected long-term rate of return on invested assets and the market related value of the assets (based on either the fair value of plan assets at the measurement date or a "calculated value" that smooths changes in fair value over a period not to exceed five years, at the employer's election).

Under IFAS, actuarial gains and losses must be recognized immediately in other comprehensive income. Gains and losses are not subsequently recognized in net income. Under U.S. GAAP, actuarial gains and losses may be recognized in net income as they occur or deferred in other comprehensive income and subsequently amortized to net income through a corridor approach.

Under IFAS, prior service costs or credits from plan amendments are recognized immediately in net income. Under U.S. GAAP, prior service costs or credits from plan amendments are initially deferred in other comprehensive income and subsequently recognized in net income over the average remaining service period of active employees or, when all or almost all participants are inactive, over the average remaining life expectancy of those participants.

Under IFAS, settlement gain or loss is recognized in net income when it occurs. Fewer events qualify as settlements under IFAS. Change in the defined benefit obligation from a curtailment is recognized in net income at the earlier of when it occurs or when related restructuring costs or termination benefits are recognized. Under U.S. GAAP, settlement gain or loss is recognized in net income when the obligation is settled. Curtailment loss is recognized in net income when the curtailment is probable of occurring and the loss is estimable, while curtailment gain is recognized in net income when the curtailment occurs.

Under IFAS, a multi-employer post-retirement plan is accounted for as either a defined contribution plan or defined benefit plan based on the terms (contractual and constructive) of the plan. If it is accounted for as a defined benefit plan, an entity must account for the proportionate share of the plan like any other defined benefit plan unless sufficient information is not available. Under U.S. GAAP, a multi-employer post-retirement plan is accounted for like a defined contribution plan.

Earnings per Share

Under IFAS, contracts that may be settled in shares or cash at the issuer's option are always assumed to be settled in shares. Under U.S. GAAP, contracts that may be settled in shares or cash at

the issuer's option are presumed to be settled in shares unless evidence is provided to the contrary (i.e. the issuer's past practice or stated policy is to settle in cash).

Under IFAS, in computing the year-to-date and annual diluted earnings per share ("EPS") for options and warrants (using the treasury stock method) and for contingently issuable shares, regardless of whether the period is profitable, the number of incremental shares is computed as if the entire year-to-date period were "the period" (i.e. not to average the current quarter with each of the prior quarters). Under U.S. GAAP, in computing the year-to-date and annual diluted EPS for options and warrants (using the treasury stock method) and for contingently issuable shares, for year-to-date and annual computations when each period is profitable, the number of incremental shares added to the denominator is the weighted average of the incremental shares that were added to the denominator in each of the quarterly computations.

Under IFAS, for options, warrants, and their equivalents, IFAS does not explicitly require assumed proceeds under the treasury stock method to include the income tax effects on additional paid-in capital. Under U.S. GAAP, assumed proceeds under the treasury stock method exclude the income tax effects of share-based payment awards because they are no longer recognized in additional paid-in capital.

Under IFAS, potentially issuable shares in a contingently convertible debt situation are considered "contingently issuable" and are included in diluted EPS using the "if-converted" method only if the contingencies are satisfied at the end of the reporting period. Under U.S. GAAP, potentially issuable shares in a contingently convertible debt situation are included in diluted EPS using the "if-converted" method if one or more contingencies relate to a market price trigger (e.g. the entity's share price), even if the market price trigger is not satisfied at the end of the reporting period.

Segment Reporting

Under IFAS, all entities determine segments based on the management approach, regardless of form of organization. Under U.S. GAAP, entities with a "matrix" form of organization must determine segments based on products and services.

Subsequent Events

Under IFAS, subsequent events are evaluated through the date that the financial statements are "authorized for issue". Depending on an entity's corporate governance structure and statutory requirements, authorization may come from management or a board of directors. Under U.S. GAAP, subsequent events are evaluated through the date the financial statements are issued (for United States Securities and Exchange Commission ("SEC") registrants and conduit bond obligors) or available to be issued (for all entities other than SEC registrants and conduit bond obligors). Financial statements are considered issued when they are widely distributed to shareholders or other users in a form that complies with U.S. GAAP. Financial statements are considered available to be issued when they are in a form that complies with U.S. GAAP and all necessary approvals have been obtained.

IFAS does not specifically address the reissuance of financial statements and recognizes only one date through which subsequent events are evaluated, that is, the date that the financial statements are authorized for issuance, even if they are being reissued. As a result, only one date will be disclosed with respect to the evaluation of subsequent events, and an entity could have adjusting subsequent events in reissued financial statements. If financial statements are reissued because of adjusting subsequent events or an error correction, the date the reissued statements are authorized for reissuance is disclosed. IFAS does not address the presentation of re-issued financial statements in an offering

document when the originally issued financial statements have not been withdrawn, but the reissued financial statements are provided either as supplementary information or as a re-presentation of the originally issued financial statements in an offering document in accordance with regulatory requirements. Under U.S. GAAP, if the financial statements are reissued, events or transactions may have occurred that require disclosure in the reissued financial statements to keep them from being misleading. However, an entity should not recognize events occurring between the time the financial statements were issued or available to be issued and the time the financial statements were reissued unless the adjustment is required by U.S. GAAP or regulatory requirements (e.g. stock splits, discontinued operations, or the effect of adopting a new accounting standard retrospectively would give rise to an adjustment). Entities must disclose both the date that the financial statements were originally issued and the date that they were reissued if the financial statements were revised due to an error correction (i.e. a "type I" subsequent event or retrospective application of US GAAP).

Under IFAS, short–term loans refinanced after the date of the statement of financial position may not be reclassified to long-term liabilities unless the entity expected and had the discretion to refinance the obligation for at least 12 months at the date of the statement of financial position. Under U.S. GAAP, short-term loans are classified as long-term if the entity intends to refinance the loans on a long-term basis and, prior to issuing the financial statements, the entity can demonstrate an ability to refinance the loans by meeting specific criteria.

GLOSSARY

Oil and Gas Terms

"AMDAL"	means Environmental Impact Analysis (*Analisa Mengenai Dampak Lingkungan*).
"API gravity"	means American Petroleum Institute gravity, which is the inverse measure of the relative density of a petroleum liquid and the density of water.
"bottom upgrade"	means the upgrading of a refinery to produce higher value products.
"CBM"	means coal bed methane gas.
"CDU"	means crude distillation unit.
"CNG"	means compressed natural gas.
"contract area"	means a specified geographic area that is the subject of a production sharing arrangement pursuant to which an operator and its partners provide financing and technical expertise to conduct exploration, development and production operations.
"delineation well"	means a well drilled in a newly discovered or known discovery to gain further information.
"developed reserves"	means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
"development well"	means a well that is drilled to exploit the hydrocarbon accumulation defined by a delineation well.
"dry well"	an exploratory, development or delineation well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
"exploration well"	means a well that is designed to test the validity of a seismic interpretation and to confirm the presence of hydrocarbons in an undrilled formation.
"FCCU"	means fluidized catalytic cracking unit.

"floating production and storage unit"	means a floating production and storage unit, which is a vessel used for both the processing of hydrocarbons and storage of oil.
"floating storage and regasification unit"	means a floating storage and regasification unit, which is a special vessel designed for the transport of LNG.
"fractions"	chemical components of crude oil separated by a refining process.
"FTP"	means first tranche petroleum.
"HVU"	means high vacuum unit.
"ICP"	means the Indonesian Crude Price, a reference price calculated using a formula determined by the Government.
"Indonesian Participant"	means an Indonesian entity designated by SKK MIGAS, which must be offered a certain specified percentage undivided interest in the total rights and obligations under a production sharing arrangement.
"Indonesian Participation Arrangement" or "IP"	means our participation in an agreement pursuant to our role as the Indonesian Participant.
"JOB"	means joint operating body.
"JOC"	means joint operating contract.
"lead"	means preliminary interpretation of geological and geophysical information that may or may not lead to prospects.
"lifting cost"	means, for a given period, cost incurred to operate and maintain wells and related equipment and facilities.
"LNG"	means liquefied natural gas.
"LPG"	means liquefied petroleum gas.
"LSWR"	means low sulfur waxy residual fuel oil.
"MOPS"	means Mean of Platts Singapore, a measure of fuel oil pricing in Singapore. It refers to the mean price of oil traded through Singapore as per the data from Platts, a commodity information and trading company.
"NCI"	means Nelson Complexity Index, a measure of the level of complexity of a refinery's processing equipment.

"net working interest production"	means the product of multiplying gross field production by the company's equity interest in the field.
"Oil Fuel Market Index Price"	means a reference price for certain fuel products as determined by the Director General of Oil and Gas on behalf of Minister of Energy and Mineral Resources by taking into consideration oil fuels price on a certain period of time based on the calculation of the MOPS published price.
"production"	represents our Company's share of the gross production from a block or field, as the case may be, attributable to our Company's working interest.
"production capacity"	means, in respect of a facility, the maximum amount that can, or is expected to be able to, be produced by such facility.
"proved reserves"	represent those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and Government regulations.
"proved plus probable reserves"	represent proved reserves plus those reserves that are unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable.
"PSC"	means production sharing contract.
"RCC"	means residual catalytic cracker.
"reserves"	represent our Company's share of the gross reserves in a block or field, as the case may be, attributable to our Company's working interest.
"TAC"	means technical assistance contract.
"turnaround"	an event wherein an entire process unit is taken offstream for maintenance or renewal.
"UKL"	means an environmental management effort plan (Upaya Pengelolaan Lingkungan).
"UPL"	means an environmental monitoring effort plan (Upaya Pemantauan Lingkungan).

Units of Measurement

"bbl" or "bbls"	means barrel or barrels.
"bbls/d"	means barrels per day.

"bcf"	means billion cubic feet.
"bcfd"	means billion cubic feet per day.
"boe"	means barrels of oil equivalent; natural gas is converted to boe using the ratio of 1 mmcf of natural gas to 0.1726 mboe of oil equivalent, except in "Industry Overview," where natural gas is converted to boe using the ratio of one mmcf of natural gas to 0.176 mboe of oil equivalent.
"btu"	means British thermal unit.
"bbtu"	means billion British thermal units.
"bbtu/d"	means billion British thermal units per day.
"bnboe"	means billion barrels of oil equivalent.
"GW"	means gigawatt.
"GWh"	means gigawatt hour.
"kg"	means kilograms.
"KL"	means kiloliters.
"KWh"	means kilowatt hours.
"mbbls/d" or "kb/d"	means thousand barrels per day.
"mboe" or "kboe"	means thousand barrels of oil equivalent.
"mboe/d" or "kboe/d"	means thousand barrels of oil equivalent per day.
"mcf"	means thousand cubic feet.
"mcf/d"	means thousand cubic feet per day.
"mmbbls"	means million barrels.
"mmbbls/d"	means million barrels per day.
"mmboe" or "Mboe"	means million barrels of oil equivalent.
"mmboe/d" or "Mboe/d"	means million barrels of oil equivalent per day.
"mmbtu" or "mmBtu"	means million British thermal units.

“mmcf”	means million cubic feet.
“mmscfd” or “MMscfd”	means million standard cubic feet per day.
“mmcf/d” or “mmcfd”	means million cubic feet per day.
“mtoe”	means metric tons of oil equivalent.
“mmtoe”	means million metric tons of oil equivalent.
“mt”	means metric ton.
“Mton”	means thousand metric tons.
“mtpa”	means metric ton per annum.
“mtpd”	means metric ton per day.
“mmtpa” or “Mtpa”	means million metric ton per annum.
“MW”	means megawatts.
“MWh”	means megawatts hours.

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PT PERTAMINA (PERSERO)
AND ITS SUBSIDIARIES

Unaudited interim consolidated financial statements
as of March 31, 2019
and for the three-month periods ended March 31, 2019 and 2018
with reports on review of interim financial information

Audited consolidated financial statements
As of December 31, 2018, 2017, and 2016
and for the years then ended
with independent auditors' reports

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
THE UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS
AS OF MARCH 31, 2019 AND FOR THE THREE-MONTH PERIODS ENDED MARCH 31, 2019 AND 2018
WITH REPORTS ON REVIEW OF INTERIM FINANCIAL INFORMATION
AND THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS
AS OF DECEMBER 31, 2018, 2017, AND 2016 AND FOR THE YEARS THEN ENDED
WITH INDEPENDENT AUDITORS' REPORT

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PERTAMINA

DIRECTORS' STATEMENT
REGARDING THE RESPONSIBILITY FOR
THE UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS
AS OF MARCH 31, 2019, AND FOR THE THREE-MONTH PERIODS ENDED MARCH 31, 2019 AND 2018
AND THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS
AS OF DECEMBER 31, 2018, 2017, AND 2016 AND FOR THE YEARS THEN ENDED

PT PERTAMINA (PERSERO) AND SUBSIDIARIES

We, the undersigned:

1. Name : Nicke Widyawati
   Office address : Jl. Medan Merdeka Timur 1A
   Jakarta 10110
   Telephone : 021 - 3815200
   Position : President Director and CEO

2. Name : Pahala N. Mansury
   Office address : Jl. Medan Merdeka Timur 1A
   Jakarta 10110
   Telephone : 021 - 3815400
   Position : Finance Director

declare best on our best knowledge and belief that:

1. We are responsible for the preparation and fair presentation of the following accompanying consolidated financial statements of PT Pertamina (Persero) and its subsidiaries (collectively referred to as the "Group") in accordance with Indonesian Financial Accounting Standard and for the related internal control as we determine is necessary to enable the preparations of such consolidated financial statements that are free from material misstatement whether due to fraud or error:
   - The unaudited interim consolidated financial statements as of March 31, 2019 and for the three-month periods ended March 31, 2019 and 2018; and
   - The audited consolidated financial statements as of December 31, 2018, 2017, and 2016 and for the years then ended.

2. All information contained in the accompanying consolidated financial statements have been adequately and correctly disclose; and

3. The accompanying consolidated financial statements do not contain false information or facts, or omit material information or facts.

Jakarta, July 15, 2019
PT Pertamina (Persero)

METERAI TEMPEL 57C45AEF229475666 6000

Nicke Widyawati
President Director and CEO

Pahala N. Mansury
Finance Director

EY
Building a better working world

Purwantono, Sungkoro & Surja

Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

Tel : +62 21 5289 5000
Fax: +62 21 5289 4100
ey.com/id

Report on Review of Interim Financial Information

Report No. 00041/2.1032/NS.0/02/0687-1/1/VII/2019

The Shareholder and the Boards of Commissioners and Directors
PT Pertamina (Persero)

We have reviewed the accompanying interim consolidated financial statements of PT Pertamina (Persero) (the "Company") and its subsidiaries, which comprise the consolidated statement of financial position as of March 31, 2019, and the consolidated statements of profit or loss and other comprehensive income, changes in equity, and cash flows for the three-month periods ended March 31, 2019 and 2018, and a summary of significant accounting policies and other explanatory notes. Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Indonesian Financial Accounting Standards. Our responsibility is to express a conclusion on these consolidated financial statements based on our reviews.

Scope of review

We conducted our reviews in accordance with Standard on Review Engagements 2410, "Review of Interim Financial Information Performed by the Independent Auditor of the Entity", established by the Indonesian Institute of Certified Public Accountants. A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants and consequently, does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our reviews, nothing has come to our attention that causes us to believe that the accompanying interim consolidated financial statements do not present fairly, in all material respects, the consolidated financial position of PT Pertamina (Persero) and its subsidiaries as of March 31, 2019, and their consolidated financial performance and cash flows for the three-month periods ended March 31, 2019 and 2018, in accordance with Indonesian Financial Accounting Standards.

Report No. 00041/2.1032/NS.0/02/0687-1/1/VII/2019 (continued)

Other matter

This report has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1933, and is not intended to be, and should not be, used for any other purposes.

KAP Purwantono, Sungkoro & Surja

Agung Purwanto
Public Accountant Registration No. AP.0687

July 15, 2019

Building a better working world

Purwantono, Sungkoro & Surja

Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

Tel : +62 21 5289 5000
Fax: +62 21 5289 4100
ey.com/id

Independent Auditors' Report

Report No. 00042/2.1032/NS.1/02/0687-1/1/VII/2019

The Shareholder and the Boards of Commissioners and Directors
PT Pertamina (Persero)

We have audited the accompanying consolidated financial statements of PT Pertamina (Persero) (the "Company") and its subsidiaries, which comprise the consolidated statements of financial position as of December 31, 2018, 2017, and 2016, and the consolidated statements of profit or loss and other comprehensive income, changes in equity, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of such consolidated financial statements in accordance with Indonesian Financial Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on such consolidated financial statements based on our audits. We conducted our audits in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether such consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

Report No. 00042/2.1032/NS.1/02/0687-1/1/VII/2019 (continued)

Auditors' responsibility (continued)

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of PT Pertamina (Persero) and its subsidiaries as of December 31, 2018, 2017, and 2016, and their consolidated financial performance and cash flows for the years then ended, in accordance with Indonesian Financial Accounting Standards.

Other matter

This report has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1933, and is not intended to be, and should not be, used for any other purposes.

KAP Purwantono, Sungkoro & Surja

Agung Purwanto
Public Accountant Registration No. AP.0687

July 15, 2019

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
AS OF MARCH 31, 2019 AND DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	As of March 31, 2019 (Unaudited)	As of December 31, 2018	2017	2016
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	2g,2h,6	8,322,110	9,112,312	6,409,827	6,721,568
Restricted cash	2g,2h,7	109,337	108,915	119,671	122,697
Short-term investments	2h	298,421	225,199	249,282	130,820
Trade receivables	2h,2i				
Related parties	2f,41a	1,537,251	1,297,651	1,095,016	1,422,268
Third parties	8a	2,186,973	1,933,455	1,580,627	1,442,452
Due from the Government - current portion	2h,9	2,537,673	1,834,261	1,492,625	1,792,457
Other receivables	2h,2i				
Related parties	2f,41b	165,179	149,178	255,054	242,839
Third parties	8b	780,043	734,312	620,460	649,798
Inventories	2j,10	6,530,247	6,323,165	6,036,137	4,795,022
Prepaid taxes - current portion	2u,40a	499,661	820,598	794,255	567,621
Prepayments and advances	2k	703,100	534,987	476,326	503,382
Other investments	2h,11	85,089	80,171	27,328	43,190
Total Current Assets		**23,755,084**	**23,154,204**	**19,156,608**	**18,434,114**
NON-CURRENT ASSETS					
Due from the Government - net of current portion	2h,9	3,029,233	2,924,148	663,114	-
Deferred tax assets	2u,40e	1,428,753	1,441,866	1,371,080	751,463
Long-term investments	2h,2m,12	2,728,620	2,819,054	2,970,918	3,329,439
Fixed assets	2n,2o,13	12,640,777	12,859,274	12,439,511	12,156,785
Oil and gas and geothermal properties	2o,2p,14	18,541,847	18,614,286	18,031,374	16,397,662
Prepaid taxes - net of current portion	2u,40a	874,387	820,287	829,300	1,469,767
Other non-current assets	2h,15	2,086,495	2,085,333	1,977,470	1,436,864
Total Non-current Assets		**41,330,112**	**41,564,248**	**38,282,767**	**35,541,980**
TOTAL ASSETS		**65,085,196**	**64,718,452**	**57,439,375**	**53,976,094**

The accompanying notes form an integral part of these consolidated financial statements.

	Notes	As of March 31, 2019 (Unaudited)	As of December 31, 2018	2017	2016
LIABILITIES					
SHORT-TERM LIABILITIES					
Short-term loans	2h,16	3,671,397	4,347,035	452,879	230,293
Trade payables	2h				
Related parties	2f,41c	53,561	78,781	49,277	118,540
Third parties	17	3,236,534	3,597,777	3,900,121	3,290,665
Due to the Government - current portion	2h,18	1,725,693	1,207,743	1,050,619	952,545
Taxes payable	2u,40b				
Income taxes		521,418	467,605	308,803	475,576
Other taxes		299,803	258,405	250,533	251,553
Accrued expenses	2h,19	2,345,494	2,135,509	2,019,896	1,596,612
Long-term liabilities - current portion	2h,2o,20	423,322	420,577	365,959	722,200
Other payables	2h				
Related parties	2f,41d	38,772	54,011	56,625	50,947
Third parties		1,429,756	1,203,426	1,121,494	1,026,808
Deferred revenue - current portion	2r	169,848	202,013	260,838	177,499
Total Short-term Liabilities		13,915,598	13,972,882	9,837,044	8,893,238
LONG-TERM LIABILITIES					
Due to the Government net of current portion	2h,18	790,351	795,082	780,626	732,573
Deferred tax liabilities	2u,40e	3,354,850	3,307,406	2,848,152	2,528,517
Long-term liabilities - net of current portion	2h,2o,20	1,651,892	1,805,300	2,109,767	2,716,909
Bonds payable	2h,21	11,099,807	11,094,096	10,385,873	9,772,656
Employee benefits liabilities	2s,22	1,905,183	1,850,383	2,208,220	2,058,732
Provision for decommissioning and site restoration	2q,23	2,050,189	2,029,735	2,129,337	1,900,093
Deferred revenue - net of current portion	2r	77,289	74,623	42,716	65,715
Other non-current payables	2h	118,124	178,905	84,373	62,903
Total Long-term Liabilities		21,047,685	21,135,530	20,589,064	19,838,098
TOTAL LIABILITIES		34,963,283	35,108,412	30,426,108	28,731,336

The accompanying notes form an integral part of these consolidated financial statements.

	Notes	As of March 31, 2019 (Unaudited)	As of December 31, 2018	2017	2016
EQUITY					
Equity Attributable to Owners of the Parent Entity					
Share capital					
Authorized – 600,000,000 (2019 and 2018) and 200,000,000 (2017 and 2016) ordinary shares at par value of Rp1,000,000 (full amount) per share					
Issued and paid-up - 171,227,044 shares (2019 and 2018); 133,090,697 shares (2017 and 2016)	25a	16,191,204	16,191,204	13,417,047	13,417,047
Additional paid-in capital	25b	(924,296)	(924,296)	2,736	2,736
Merging entity's equity			-	1,804,579	1,801,742
Government contributed assets pending final clarification of status	26	401,120	401,120	1,361	1,361
Other equity components		208,641	607,564	487,699	664,617
Retained earnings	27				
- Appropriated		8,796,357	8,796,357	6,871,101	4,631,441
- Unappropriated		3,045,887	2,526,772	2,540,195	3,147,043
Total Equity Attributable to Owners of the Parent Entity		27,718,913	27,598,721	25,124,718	23,665,987
Non-controlling interests	2c,24	2,403,000	2,011,319	1,888,549	1,578,771
Total Equity		30,121,913	29,610,040	27,013,267	25,244,758
TOTAL LIABILITIES AND EQUITY		65,085,196	64,718,452	57,439,375	53,976,094

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PROFIT OR LOSS AND COMPREHENSIVE INCOME
FOR THE THREE-MONTH PERIODS ENDED MARCH 31, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the three-month periods ended March 31, 2019 (Unaudited)	For the three-month periods ended March 31, 2018 (Unaudited)	For the years ended December 31, 2018	For the years ended December 31, 2017	For the years ended December 31, 2016
Sales and other operating revenues	2r					
Domestic sales of crude oil, natural gas, geothermal energy and oil products	28	10,317,993	10,713,999	44,742,511	39,788,784	35,841,696
Subsidy reimbursements from the Government	29	1,212,497	1,342,764	5,632,468	3,572,084	2,568,844
Export of crude oil, natural gas and oil products	30	867,334	747,940	3,636,953	1,874,281	968,371
Marketing fees		2,901	1,782	15,432	25,474	(257,485)
Revenues from other operating activities	31	269,462	325,387	3,906,207	740,100	690,511
TOTAL SALES AND OTHER OPERATING REVENUES		12,670,187	13,131,872	57,933,571	46,000,723	39,811,937
Cost of sales and other direct costs	2r					
Cost of goods sold	32	(9,013,146)	(9,632,018)	(42,787,916)	(33,175,656)	(26,180,963)
Upstream production and lifting costs	33	(1,160,904)	(1,224,063)	(4,386,516)	(3,421,207)	(3,270,000)
Exploration costs	34	(25,750)	(63,839)	(267,680)	(165,356)	(109,196)
Expenses from other operating activities	35	(377,431)	(300,085)	(1,271,977)	(862,962)	(703,492)
TOTAL COST OF SALES AND OTHER DIRECT COSTS		(10,577,231)	(11,220,005)	(48,714,089)	(37,625,181)	(30,263,651)
GROSS PROFIT		2,092,956	1,911,867	9,219,482	8,375,542	9,548,286
Selling and marketing expenses	2r,36	(445,953)	(294,233)	(1,642,831)	(1,590,202)	(1,339,566)
General and administrative expenses	2r,37	(394,793)	(281,235)	(1,329,911)	(1,598,934)	(1,509,290)
Gain (loss) on foreign exchange - net	2r,2t	119,907	(67,505)	19,622	58,137	(57,521)
Finance income	2r,38	145,872	48,046	256,573	233,074	336,634
Finance costs	2r,38	(241,459)	(204,360)	(835,238)	(817,711)	(770,518)
Share in net profit of associates and joint ventures	2c,2r	15,773	124,893	122,724	37,904	18,722
Other income (expenses) - net	2r,39	(98,670)	179,927	(80,825)	(830,582)	(877,864)
		(899,323)	(494,467)	(3,489,886)	(4,508,314)	(4,199,403)
PROFIT BEFORE INCOME TAX		1,193,633	1,417,400	5,729,596	3,867,228	5,348,883
Income tax expense - net	2u,40c	(620,276)	(729,633)	(3,013,202)	(1,166,824)	(1,877,649)
PROFIT FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		573,357	687,767	2,716,394	2,700,404	3,471,234

The accompanying notes form an integral part of these consolidated financial statements.

	Notes	For the three-month periods ended March 31, 2019 (Unaudited)	For the three-month periods ended March 31, 2018 (Unaudited)	For the years ended December 31, 2018	For the years ended December 31, 2017	For the years ended December 31, 2016
PROFIT FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		573,357	687,767	2,716,394	2,700,404	3,471,234
OTHER COMPREHENSIVE (LOSS) INCOME						
Items not to be reclassified to profit or loss in subsequent periods (net of tax):						
Remeasurement of net defined benefit liability	2s	(28,672)	75,549	228,498	(129,059)	(73,373)
Items to be reclassified to profit or loss in subsequent periods (net of tax):						
Foreign exchange difference from translation of financial statements in foreign currency	2c,2t	36,413	5,433	(79,561)	7,060	14,684
Share of other comprehensive Income (loss) of associates	2c,2m	(69,225)	(21,280)	(130,775)	(25,134)	1,482
Other comprehensive income (loss) - net of tax		(61,484)	59,702	18,162	(147,133)	(57,207)
TOTAL COMPREHENSIVE INCOME FOR THE PERIOD/YEAR AFTER THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT		511,873	747,469	2,734,556	2,553,271	3,414,027
Adjustment of merging entity's income:						
Owners of the parent entity		-	(45,770)	(45,770)	(81,537)	(173,339)
Non-controlling interests	2c	-	(34,585)	(34,585)	(66,248)	(135,241)
		-	(80,355)	(80,355)	(147,785)	(308,580)
PROFIT FOR THE PERIOD/YEAR BEFORE THE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT ATTRIBUTABLE TO:						
Owners of the parent entity		519,115	534,581	2,526,772	2,540,195	3,147,043
Non-controlling interests	2c	54,242	72,831	109,267	12,424	15,611
		573,357	607,412	2,636,039	2,552,619	3,162,654
Adjustment of merging entity's comprehensive income:						
Owners of the parent		-	(42,546)	(42,546)	(80,710)	(176,957)
Non-controlling interests	2c	-	(32,682)	(32,682)	(65,549)	(138,292)
		-	(75,228)	(75,228)	(146,259)	(315,249)
TOTAL COMPREHENSIVE INCOME FOR THE PERIOD/YEAR BEFORE EFFECT OF MERGING ENTITY'S INCOME ADJUSTMENT ATTRIBUTABLE TO:						
Owners of the parent		120,192	608,221	2,536,559	2,363,277	3,081,541
Non-controlling interests	2c	391,681	64,020	122,769	43,735	17,237
		511,873	672,241	2,659,328	2,407,012	3,098,778

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE THREE-MONTHS PERIODS ENDED MARCH 31, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity											
							Other equity components						
	Notes	Issued and paid-up capital	Advance for share issuance	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
									Appropriated	Unappropriated			
Balance as of January 1, 2016/ December 31, 2015		9,864,901	3,552,146	1,720,396	2,736	1,361	(321,181)	1,051,300	3,710,670	1,420,220	21,002,549	1,495,494	22,498,043
Adjustment of merging entity's comprehensive income for the year		-	-	176,957	-	-	-	-	-	-	176,957	138,292	315,249
Adjustment of merging entity's other equity transaction		-	-	(95,611)	-	-	-	-	-	-	(95,611)	(72,252)	(167,863)
Differences arising from translation of non-US Dollar currency financial statements	2c,2t	-	-	-	-	-	16,980	-	-	-	16,980	(3,181)	13,799
Other comprehensive income from associates		-	-	-	-	-	-	(6,144)	-	-	(6,144)	4,270	(1,874)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	-	(76,338)	-	-	(76,338)	537	(75,801)
Dividends declared	2aa,27	-	-	-	-	-	-	-	-	(499,449)	(499,449)	-	(499,449)
Appropriation of other reserves	27	-	-	-	-	-	-	-	920,771	(920,771)	-	-	-
Capitalization of advance for share issuance		3,552,146	(3,552,146)	-	-	-	-	-	-	-	-	-	-
Profit for the year		-	-	-	-	-	-	-	-	3,147,043	3,147,043	15,611	3,162,654
Balance as of December 31, 2016		13,417,047	-	1,801,742	2,736	1,361	(304,201)	968,818	4,631,441	3,147,043	23,665,987	1,578,771	25,244,758

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE THREE-MONTHS PERIODS ENDED MARCH 31, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entity's equity	Additional paid-in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2017/ December 31, 2016		13,417,047	1,801,742	2,736	1,361	(304,201)	968,818	4,631,441	3,147,043	23,665,987	1,578,771	25,244,758
Impact of consolidated beginning balance of non-controlling interest Etablissements Maurel et Prom SA		-	-	-	-	-	-	-	-	-	252,158	252,158
Adjustment of merging entity's comprehensive income for the year		-	80,710	-	-	-	-	-	-	80,710	65,549	146,259
Adjustment of merging entity's other equity transaction		-	(77,873)	-	-	-	-	-	-	(77,873)	(51,664)	(129,537)
Differences arising from translation of non-US Dollar currency financial statements	2c,2t	-	-	-	-	1,225	-	-	-	1,225	3,271	4,496
Other comprehensive income from associates		-	-	-	-	-	(55,421)	-	-	(55,421)	28,050	(27,371)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	(122,722)	-	-	(122,722)	(10)	(122,732)
Dividends declared	2aa,27	-	-	-	-	-	-	-	(907,383)	(907,383)		(907,383)
Appropriation of other reserves	27	-	-	-	-	-	-	2,239,660	(2,239,660)	-	-	-
Profit for the year		-	-	-	-	-	-	-	2,540,195	2,540,195	12,424	2,552,619
Balance as of December 31, 2017		13,417,047	1,804,579	2,736	1,361	(302,976)	790,675	6,871,101	2,540,195	25,124,718	1,888,549	27,013,267

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE THREE-MONTHS PERIODS ENDED MARCH 31, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components		Retained earnings				
	Notes	Issued and paid-up capital	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Appropriated	Unappropriated	Total	Non-controlling interests	Total equity
Balance as of January 1, 2018/ December 31, 2017		13,417,047	1,804,579	2,736	1,361	(302,976)	790,675	6,871,101	2,540,195	25,124,718	1,888,549	27,013,267
Adjustment of merging entity's comprehensive income for the year		-	42,546	-	-	-	-	-	-	42,546	32,682	75,228
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk and PT Pertamina Internasional Eksplorasi dan Produksi		-	-	-	-	-	-	-	-	-	-	-
Capitalization of advance for share issuance		2,774,157	(1,847,125)	(927,032)	-	-	-	-	-	-	-	-
Government assistance whose status has not been determined	26	-	-	-	-	-	-	-	-	-	-	-
Differences arising from translation of non-US Dollar financial statements	2c,2t	-	-	-	-	(1,560)	-	-	-	(1,560)	6,993	5,433
Other comprehensive income from associates		-	-	-	-	-	34,637	-	-	34,637	(55,917)	(21,280)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	68,119	-	-	68,119	7,430	75,549
Dividends declared	2aa,27	-	-	-	-	-	-	-	-	-	-	-
Appropriation of other reserves	27	-	-	-	-	-	-	-	-	-	-	-
Profit for the period		-	-	-	-	-	-	-	534,581	534,581	72,831	607,412
Balance as of March 31, 2018 (unaudited)		16,191,204	-	(924,296)	1,361	(304,536)	893,431	6,871,101	3,074,776	25,803,041	1,952,568	27,755,609

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE THREE-MONTHS PERIODS ENDED MARCH 31, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity										
						Other equity components						
	Notes	Issued and paid-up capital	Merging entities equity	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other compre-hensive income	Retained earnings		Total	Non-controlling interests	Total equity
								Appropriated	Unappropriated			
Balance as of January 1, 2018/ December 31, 2017		13,417,047	1,804,579	2,736	1,361	(302,976)	790,675	6,871,101	2,540,195	25,124,718	1,888,549	27,013,267
Adjustment of merging entity's comprehensive income for the year		-	42,546	-	-	-	-	-	-	42,546	32,682	75,228
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk and PT Pertamina Internasional Eksplorasi dan Produksi		-	-	-	-	-	13,710	-	-	13,710	68,814	82,524
Capitalization of advance for share issuance		2,774,157	(1,847,125)	(927,032)	-	-	-	-	-	-	-	-
Government contributed assets pending final clarification of status	26	-	-	-	399,759	-	-	-	-	399,759	-	399,759
Differences arising from translation of non-US Dollar currency financial statements	2c,2t	-	-	-	-	(59,338)	-	-	-	(59,338)	(20,223)	(79,561)
Other comprehensive income from associates		-	-	-	-	-	(69,138)	-	-	(69,138)	(61,637)	(130,775)
Remeasurements of net defined benefit liability	2s	-	-	-	-	-	234,631	-	-	234,631	(6,133)	228,498
Dividends declared	2aa,27	-	-	-	-	-	-	-	(614,939)	(614,939)	-	(614,939)
Appropriation of other reserves	27	-	-	-	-	-	-	1,925,256	(1,925,256)	-	-	-
Profit for the year		-	-	-	-	-	-	-	2,526,772	2,526,772	109,267	2,636,039
Balance as of December 31, 2018		16,191,204	-	(924,296)	401,120	(362,314)	969,878	8,796,357	2,526,772	27,598,721	2,011,319	29,610,040

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)
FOR THE THREE-MONTHS PERIODS ENDED MARCH 31, 2019 AND 2018, AND THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

		Attributable to owners of the parent entity									
					Other equity components						
	Notes	Issued and paid-up capital	Additional paid in capital	Government contributed assets pending final clarification of status	Differences arising from translation of non US$ currency financial statements	Other comprehensive income	Retained earnings		Total	Non-controlling interests	Total equity
							Appropriated	Unappropriated			
Balance as of January 1, 2019/ December 31, 2018		16,191,204	(924,296)	401,120	(362,314)	969,878	8,796,357	2,526,772	27,598,721	2,011,319	29,610,040
Merging entities Income		-	-	-	-	-	-	-	-	-	-
Change in ownership in PT Asuransi Tugu Pratama Indonesia Tbk and PT Pertamina Internasional Eksplorasi dan Produksi		-	-	-	-	-	-	-	-	-	-
Capitalization of advance for share issuance		-	-	-	-	-	-	-	-	-	-
Government assistance whose status has not been determined	26	-	-	-	-	-	-	-	-	-	-
Differences arising from translation of financial statements	2c,2t	-	-	-	6,617	-	-	-	6,617	29,796	36,413
Other comprehensive income from associates		-	-	-	-	(376,695)	-	-	(376,695)	307,470	(69,225)
Remeasurements of net defined benefit liability	2s	-	-	-	-	(28,845)	-	-	(28,845)	173	(28,672)
Dividends declared	2aa,27	-	-	-	-	-	-	-	-	-	-
Appropriation of other reserves	27	-	-	-	-	-	-	-	-	-	-
Profit for the period		-	-	-	-	-	-	519,115	519,115	54,242	573,357
Balance as of March 31, 2019 (unaudited)		16,191,204	(924,296)	401,120	(355,697)	564,338	8,796,357	3,045,887	27,718,913	2,403,000	30,121,913

The accompanying notes form an integral part of these consolidated financial statements.

PT PERTAMINA (PERSERO) AND ITS SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE THREE-MONTH PERIODS ENDED MARCH 31, 2019 AND 2018,
AND FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Expressed in thousands of United States Dollars, unless otherwise stated)

	Notes	For the three-month periods ended March 31, 2019 (Unaudited)	For the three-month periods ended March 31, 2018 (Unaudited)	For the years ended December 31, 2018	2017	2016
Cash flows from operating activities:						
Cash receipts from customers		11,953,530	12,316,075	48,878,496	40,220,288	42,723,514
Cash receipts from government		974,048	1,136,939	7,805,648	3,787,855	3,722,302
Cash receipts from tax restitutions		3,050	1,886	185,016	616,698	39,492
Payments to suppliers		(8,877,812)	(10,055,046)	(38,227,640)	(29,261,802)	(29,211,891)
Payments to the government		(2,250,141)	(2,337,354)	(11,279,557)	(7,524,628)	(5,173,462)
Payments of corporate income taxes		(642,787)	(567,484)	(2,688,175)	(2,100,297)	(2,009,016)
Cash paid to employees and management		(445,179)	(487,357)	(1,640,855)	(1,540,805)	(1,321,422)
Receipts from (placement of) restricted cash		30	(18,792)	73,109	(156,047)	(494,035)
Receipts of interest		43,772	20,547	63,327	35,616	115,711
Net cash generated from operating activities		758,511	9,414	3,169,369	4,076,878	8,391,193
Cash flows from investing activities:						
Proceeds from disposal of short-term investments		24,637	25,050	198,439	99,870	45,807
Proceeds from disposal of long-term investments		-	-	-	15,801	4,647
Interest received from investments		1,945	5,835	13,784	18,240	3,987
Cash receipts from other investing activities		2,055	84,677	262,222	28,681	-
Proceeds from sale of fixed assets		153	157	176	102	2,161
Dividends received form associates		6	2,313	214,083	81,648	233,632
Purchases of fixed assets		(196,019)	(163,504)	(1,287,975)	(981,944)	(1,012,676)
Purchases of oil and gas, and geothermal properties		(421,640)	(257,670)	(1,482,518)	(891,964)	(1,365,114)
Placements in long-term invesments		(26,742)	(22,744)	(1,062,244)	(659,992)	(336,518)
Placements in short-term investments		(17,203)	(35,382)	(237,577)	(226,322)	(142,759)
Payments for exploration and evaluation assets		(4,609)	(7,803)	(99,538)	(37,200)	(18,438)
Placement of restricted cash		(5)	(5)	(22,614)	(29,433)	(10,286)
Addition of participating interest		-	-	-	-	(23,796)
Cash obtained due to change of control		-	-	-	203,230	-
Net cash used in investing activities		(637,422)	(369,076)	(3,503,762)	(2,379,283)	(2,619,353)

The accompanying notes form an integral part of these consolidated financial statements.

	Notes	For the three-month periods ended March 31, 2019 (Unaudited)	For the three-month periods ended March 31, 2018 (Unaudited)	For the years ended December 31, 2018	For the years ended December 31, 2017	For the years ended December 31, 2016
Cash flows from financing activities:						
Proceeds from short-term loans	46	1,079,269	830,348	9,489,219	4,039,533	2,377,255
Proceeds from bond issuance	46	-	-	734,407	-	-
Proceeds from long-term loans	46	51,280	44,381	255,931	1,288,204	1,674,448
Repayments of short-term loans	46	(1,885,742)	(830,262)	(5,583,278)	(3,786,723)	(4,057,881)
Repayments of long-term loans	46	(182,169)	(201,764)	(465,351)	(2,109,038)	(2,248,368)
Dividend payments	27,46	-	-	(585,755)	(867,751)	(554,859)
Payments of finance costs		(18,082)	(15,857)	(538,489)	(523,147)	(530,823)
Repayments of bonds	46	-	-	(37,649)	-	(139,756)
Receipts from (placement of) restricted cash		(725)	105	(312)	(13,249)	394
Net cash generated from (used in) financing activities		(956,169)	(173,049)	3,268,723	(1,972,171)	(3,479,590)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(835,080)	(532,711)	2,934,330	(274,576)	2,292,250
Effect of exchange rate changes on cash and cash equivalents		44,878	(44,652)	(231,845)	(37,165)	20,652
CASH AND CASH EQUIVALENTS AT BEGINNING OF THE YEAR	6	9,112,312	6,409,827	6,409,827	6,721,568	4,408,666
CASH AND CASH EQUIVALENTS AT END OF THE YEAR	6	8,322,110	5,832,464	9,112,312	6,409,827	6,721,568

The accompanying notes form an integral part of these consolidated financial statements.

1. GENERAL

a. PT Pertamina (Persero) ("the Company")

i. Company profile

The Company was established in accordance with Notarial Deed No. 20 dated September 17, 2003 of Lenny Janis Ishak, S.H. The Company's deed of establishment was approved by the Minister of Law and Human Rights through Letter No. C-24025 HT.01.01.TH.2003 dated October 9, 2003 and through Circular Letter No. 93 attachments No. 11620 dated November 21, 2003. The establishment of the Company is based on Law No. 1 Year 1995 dated March 7, 1995 regarding Limited Liability Company ("PT"), Government Regulation ("PP") No. 12 Year 1998 dated January 17, 1998 regarding the Company (Persero), and PP No. 45 Year 2001 dated June 5, 2001 regarding Amendments to PP No. 12 Year 1998, Law No. 22 Year 2001 dated November 23, 2001 regarding Oil and Gas, Law No. 19 Year 2003 dated June 19, 2003 regarding State-Owned Enterprises ("BUMN"), and PP No. 31 Year 2003 dated June 18, 2003 regarding changes in the status of Perusahaan Pertambangan Minyak dan Gas Bumi Negara (Pertamina, "the former Pertamina Entity") to a state Enterprise (Persero).

The Company's Articles of Association have been amended several times. The latest amendment was made to increase the authorized capital of the Company, under Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., which was approved by the Minister of Law and Human Rights through Decision Letter No. AHU-0008395.AH.01.02. Year 2018 dated April 13, 2018.

In accordance with PP No. 31 Year 2003, all rights and obligations arising from contracts and agreements entered between the former Pertamina Entity and third parties, provided these are not contrary to Law No. 22 Year 2001, were transferred to the Company. In accordance with PP No. 31 Year 2003, the objective of the Company is to engage in the oil and gas business in domestic and foreign markets and in other related business activities. In conducting its business, the Company's objective is to generate income and contribute to the improvement of the economy for the benefit of the people of Indonesia.

At the date of establishment of the Company, all oil and gas and geothermal energy activities of the former Pertamina Entity, including joint operations with other companies, were transferred to the Company. These businesses have been transferred to the Company's subsidiaries. All employees of the former Pertamina Entity became employees of the Company.

ii. Business activities and principal address

In accordance with its Articles of Association under Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., which was registered by the Minister of Law and Human Rights through its Letter No. AHU-0008395.AH.01.02. Year 2018 dated April 13, 2018, the Company shall conduct the following main business:

a. Operate in exploration activities of oil and gas;
b. Operate in exploitation activities of oil and gas;
c. Carry out activities in electrical energy, including but not limited to the exploration and exploitation of geothermal energy, geothermal electricity power plant ("PLTP"), gas power plant ("PLTG") and electricity energy produced by the Company;
d. Implement refining activities that produce fuel oil, special fuel, non-fuel, petrochemicals, gas fuel, Liquified Natural Gas ("LNG") and Gas to Liquid ("GTL") result/other product either and products or intermediate products;
e. Conduct activities of the procurement of raw materials, processing, transportation, storage and trading of Biofuels;
f. Conduct operational activities, which includes the transport of petroleum, natural gas, fuel oil, fuel gas and/or result/other products for commercial purposes;
g. Carry out storage activities which includes the reception, the collection and spending of petroleum reservoirs, fuel oil, fuel gas and/or result/other products for commercial purposes;
h. Carry out commercial trade activities which includes the purchase, sale, export and import of petroleum, fuel oil, fuel gas and/or result/other products; the distribution of natural gas through pipelines including commercial electrical energy produced by the Company; and
i. Conduct developmental activities, exploration, production and trading of new and renewable energy, among others, Coal Bed Methane ("CBM"), liquified coal, gasified coal, shale gas, shale oil, bio fuel, diesel fuel, wind energy and biomass.

1. GENERAL (continued)

a. PT Pertamina (Persero) (the Company) (continued)

ii. Business activities and principal address (continued)

In addition to the above main business activities, the Company may conduct business in order to optimize the utilization of available resources as follows:

a. Trading house, real estate, warehousing, tourism, resort, sports and recreation, rest areas, hospitals, education, research, infrastructure, telecommunications, rental services and operation of facilities and infrastructure owned by the Company, the freeway (toll) and shopping centre/mall;
b. Management of Special Economic Zones;
c. Industrial complex management; and
d. Other business activities and association to support its main business.

The Company has processing activities which include the processing of crude oil into oil products and production of Liquified Petroleum Gas ("LPG") and petrochemicals (paraxylene and propylene). The Company owns six Refinery Units ("RU") with installed processing capacities as follows:

RU	Installed processing capacity of crude oil (barrels/day) (unaudited)
RU II - Dumai and Sungai Pakning, Riau	170,000
RU III - Plaju and Sungai Gerong, South Sumatera	133,700
RU IV - Cilacap, Central Java	348,000
RU V - Balikpapan, East Kalimantan	260,000
RU VI - Balongan, West Java	125,000
RU VII - Kasim, West Papua	10,000

The Company, through its subsidiaries, also conduct certain business activities as disclosed in Notes 1b and 43.

The Company's head office is located at Jl. Medan Merdeka Timur No. 1A, Jakarta, Indonesia.

iii. The Company's Board of Commissioners and Board of Directors

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Board of Commissioners are as follows:

		December 31,		
	March 31, 2019[a]	2018[a]	2017[b]	2016[c]
President Commissioner	Tanri Abeng[d]	Tanri Abeng[d]	Tanri Abeng[d]	Tanri Abeng[d]
Vice President Commissioner	Arcandra Tahar	Arcandra Tahar	Arcandra Tahar	Arcandra Tahar
Commissioner	Sahala Lumban Gaol	Sahala Lumban Gaol	Sahala Lumban Gaol	Sahala Lumban Gaol
Commissioner	Suahasil Nazara	Suahasil Nazara	Suahasil Nazara	Suahasil Nazara
Commissioner	Ahmad Bambang	Ahmad Bambang	Edwin Hidayat Abdullah	Edwin Hidayat Abdullah
Commissioner	Alexander Lay	Alexander Lay	Alexander Lay	-
Commissioner	Ego Syahrial	Ego Syahrial	-	-

[a] Based on resolution No. SK-142/MBU/05/2018 of the General Meeting Shareholder ("GMS") dated May 30, 2018
[b] Based on resolution No. SK-194/MBU/09/2017 of the GMS dated September 12, 2017
[c] Based on resolution No. SK-68/MBU/03/2016 of the GMS dated March 29, 2016 and No. SK-254/MBU/11/2016 dated November 14, 2016
[d] Independent Commissioner

1. GENERAL (continued)

a. PT Pertamina (Persero) (the Company) (continued)

iii. The Company's Board of Commissioners and Board of Directors (continued)

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Board of Directors are as follows:

		December 31,		
	March 31, 2019	2018	2017[d]	2016[e]
President Director	Nicke Widyawati[a]	Nicke Widyawati[a]	Elia Massa Manik	Dwi Soetjipto
Vice President Director	-	-	-	Ahmad Bambang
Marketing Director	-	-	Muchamad Iskandar	Muchamad Iskandar
Corporate Marketing Director	Basuki Trikora Putra[b]	Basuki Trikora Putra[b]	-	-
Retail Marketing Director	Mas'ud Khamid[b]	Mas'ud Khamid[b]	-	-
Upstream Director	Dharmawan H. Samsu[a]	Dharmawan H. Samsu[a]	Syamsu Alam	Syamsu Alam
Gas Director	-	-	Yenni Andayani	Yenni Andayani
New and Renewable Energy Director	-	-	-	-
Finance Director	Pahala N. Mansury[c]	Pahala N. Mansury[c]	Arief Budiman	-
Finance and Corporate Strategy Director	-	-	-	Arief Budiman
Human Resources Director	Koeshartanto[a]	Koeshartanto[a]	Nicke Widyawati	-
Human Resources and Information Technology	-	-	-	Dwi Wahyu Daryoto
Logistic, Supply Chain, and Infrastructure Director	Gandhi Sriwidodo[b]	Gandhi Sriwidodo[b]	-	-
Refinery Director	Budi Santoso Syarif[b]	Budi Santoso Syarif[b]	Toharso	Toharso
Mega Project Refinery and Petrochemical Director	Ignatius Tallulembang[c]	Ignatius Tallulembang[c]	Ardhy N. Mokobombang	Rachmad Hardadi
Planning Investment and Risk Management Director	Heru Setiawan[c]	Heru Setiawan[c]	Gigih Prakoso	-
Asset Management Director	M. Haryo Yunianto[b]	M. Haryo Yunianto[b]	Dwi Wahyu Daryoto	-

[a] Effective per August 29, 2018 based on resolution GMS No. SK-232/MBU/08/2018
[b] Effective per April 20, 2018 based on resolution GMS No. SK-97/MBU/04/2018
[c] Effective per September 13, 2018 based on resolution GMS No. SK-242/MBU/09/2018
[d] Based on resolution No. SK-52/MBU/03/2017 of the GMS dated March 16, 2017 and No. SK-256/MBU/11/2017 dated November 27, 2017
[e] Based on resolution No. SK-242/MBU/10/2016 of the GMS dated October 20, 2016 and No. SK-264/MBU/12/2016 dated December 2, 2016

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the composition of the Company's Audit Committee are as follows:

		December 31,		
	March 31, 2019	2018	2017	2016[e]
Chairman	Tanri Abeng[a]	Tanri Abeng[a]	Tanri Abeng[a]	Tanri Abeng
Vice Chairman	Sahala Lumban Gaol[c]	Sahala Lumban Gaol[c]	Sahala Lumban Gaol[c]	-
Vice Chairman	Ahmad Bambang[c]	Ahmad Bambang[c]	Edwin Hidayat Abdullah[d]	-
Member	-	-	-	Sahala Lumban Gaol
Member	-	-	Dwi Martani	Dwi Martani
Member	Agus Yulianto[b]	Agus Yulianto[b]	Agus Yulianto	Agus Yulianto
Member	Bonar Lumban Tobing[b]	Bonar Lumban Tobing[b]	Bonar Lumban Tobing	Bonar Lumban Tobing

[a] Effective per May 6, 2015 based on resolution No. SK-60/MBU/05/2015
[b] Effective per January 1, 2016 based on resolution No. 023/KPTS/K/DK/2015
[c] Effective per July 18, 2018 based on resolution No. 005/KPTS/K/DK/2018
[d] Effective per November 14, 2016 based on resolution No. SK-254/MBU/K/11/2016
[e] Effective per September 12, 2017 based on resolution No. SK-194/MBU/K/09/2017

iv. Number of employees

As of March 31, 2019 and 2018, and December 31, 2018, 2017, and 2016, the Group has 31,362; 29,779; 31,569; 30,118; and 29,469 permanent employees (unaudited), respectively.

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements

i. Subsidiaries

As of March 31, 2019, and December 31, 2018, 2017, and 2016 the Group has direct or indirect control of the following subsidiaries:

Subsidiaries	Year of establishment	Percentage of ownership			
		March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Oil and gas exploration and production					
1. PT Pertamina Hulu Energi	1990	100.00%	100.00%	100.00%	100.00%
2. PT Pertamina EP	2005	100.00%	100.00%	100.00%	100.00%
3. PT Pertamina EP Cepu	2005	100.00%	100.00%	100.00%	100.00%
4. Pertamina E&P Libya Limited, British Virgin Island	2005	100.00%	100.00%	100.00%	100.00%
5. PT Pertamina East Natuna 100.00%	2012	100.00%	100.00%	100.00%	-
6. PT Pertamina EP Cepu ADK	2013	100.00%	100.00%	100.00%	100.00%
7. PT Pertamina Internasional Eksplorasi dan Produksi	2013	100.00%	100.00%	100.00%	100.00%
8. ConocoPhillips Algeria Limited, Cayman Island *)	2013	100.00%	100.00%	100.00%	100.00%
9. PT Pertamina Hulu Indonesia	2015	100.00%	100.00%	100.00%	100.00%
10. PT Pertamina Hulu Rokan (Note 4g)	2018	100.00%	100.00%	-	-
Geothermal exploration and production					
11. PT Pertamina Geothermal Energy	2006	100.00%	100.00%	100.00%	100.00%
Oil and gas drilling services					
12. PT Pertamina Drilling Services Indonesia	2008	100.00%	100.00%	100.00%	100.00%
Processing and sale of oil andgas products, construction andoilfield services, information technology and telecommunications					
13. PT Elnusa Tbk	1969	41.10%	41.10%	41.10%	41.10%
Oil and gas trading, gas transportation, processing, distribution and storage					
14. PT Pertamina Gas (Note 4a)	2007	-	-	100.00%	100.00%
15. PT Perusahaan Gas Negara Tbk (Note 4a)	2018	56.96%	56.96%	-	-
Electricity					
16. PT Pertamina Power Indonesia	2016	100.00%	100.00%	100.00%	100.00%
Trading services and industrial activities					
17. PT Pertamina Patra Niaga	1997	100.00%	100.00%	100.00%	100.00%
18. Pertamina International Timor S,A	2015	95.00%	95.00%	95.00%	95.00%
Public fuel filling stations business					
19. PT Pertamina Retail	1997	100.00%	100.00%	100.00%	100.00%
Lubricant processing and marketing					
20. PT Pertamina Lubricants	2013	100.00%	100.00%	100.00%	100.00%
Shipping					
21. PT Pertamina Trans Kontinental	1969	100.00%	100.00%	100.00%	100.00%
22. PT Pertamina International Shipping	2016	100.00%	100.00%	100.00%	100.00%
Air transportation services					
23. PT Pelita Air Service	1970	100.00%	100.00%	100.00%	100.00%
Investment management					
24. PT Pertamina Pedeve Indonesia (formerly PT Pertamina Dana Ventura)	2002	100.00%	100.00%	100.00%	100.00%
Human resources development services					
25. PT Pertamina Training & Consulting	1999	100.00%	100.00%	100.00%	100.00%
Offices, house rental and hotel operations					
26. PT Patra Jasa	1975	100.00%	100.00%	100.00%	100.00%

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

i. Subsidiaries (continued)

Subsidiaries	Year of establishment	Percentage of ownership			
		March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Health services and hospital operations					
27. PT Pertamina Bina Medika	1997	100.00%	100.00%	100.00%	100.00%
Insurance services					
28. PT Asuransi Tugu Pratama Indonesia Tbk (formerly PT Tugu Pratama Indonesia) ("ATPI") **	1981	58.50%	58.50%	65.00%	65.00%
Refineries					
29. PT Kilang Pertamina Internasional	2017	100.00%	100.00%	100.00%	-
Liquified Natural Gas ("LNG")					
30. PT Nusantara Regas (Note 4b)	2010	82.78%	82.78%	60.00%	60.00%

Subsidiaries	Year of establishment	Total assets before elimination			
		March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Oil and gas exploration and prouction					
1. PT Pertamina Hulu Energi	1990	4,728,090	4,531,667	4,780,787	4,908,390
2. PT Pertamina EP	2005	7,657,164	7,498,644	7,621,461	7,301,605
3. PT Pertamina EP Cepu	2005	3,279,375	2,992,894	2,608,022	2,103,211
4. Pertamina E&P Libya Limited, British Virgin Island	2005	154	154	154	154
5. PT Pertamina East Natuna	2012	129	129	129	129
6. PT Pertamina EP Cepu ADK	2013	11,623	12,847	18,534	58,545
7. PT Pertamina Internasional Eksplorasi dan Produksi	2013	5,774,800	5,841,041	5,776,299	4,598,908
8. ConocoPhillips Algeria Limited, Cayman Island *)	2013	774,216	774,216	1,065,720	1,065,720
9. PT Pertamina Hulu Indonesia	2015	1,892,097	1,478,109	304,838	41,112
10. PT Pertamina Hulu Rokan (Note 4g)	2018	785,000	785,000	-	-
Geothermal exploration and production					
11. PT Pertamina Geothermal Energy	2006	2,509,703	2,556,651	2,408,120	2,073,789
Oil and gas drilling services					
12. PT Pertamina Drilling Services Indonesia	2008	527,560	560,423	574,402	590,357
Processing and sale of oil andgas products, construction andoilfield services, information technology and telecommunications					
13. PT Elnusa Tbk	1969	413,566	390,995	358,319	311,920
Oil and gas trading, gas transportation, processing, distribution and storage					
14. PT Pertamina Gas (Note 4a)	2007	-	-	1,926,760	1,877,883
15. PT Perusahaan Gas Negara Tbk (Note 4a)	2018	7,508,677	8,764,437	6,293,129	6,834,153
Electricity					
16. PT Pertamina Power Indonesia	2016	113,127	114,721	99,726	101,149
Trading services and industrial activities					
17. PT Pertamina Patra Niaga	1997	935,568	908,986	960,394	783,409
18. Pertamina International Timor S,A,	2015	39,941	36,643	28,677	18,712
Public fuel filling stations business					
19. PT Pertamina Retail	1997	208,740	203,312	150,643	136,686
Lubricant processing and marketing					
20. PT Pertamina Lubricants	2013	446,512	413,332	500,637	510,968
Shipping					
21. PT Pertamina Trans Kontinental	1969	308,015	307,519	287,014	254,017
22. PT Pertamina International Shipping	2016	316,173	296,335	217,466	10,000

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

(i) Subsidiaries (continued)

Subsidiaries	Year of establishment	Total assets before elimination			
		March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Air transportation services					
23. PT Pelita Air Service	1970	60,348	60,380	65,300	63,990
Investment management					
24. PT Pertamina Pedeve Indonesia (formerly PT Pertamina Dana Ventura)	2002	63,690	62,098	71,327	157,691
Human resources development services					
25. PT Pertamina Training & Consulting	1999	37,741	39,799	40,768	32,624
Offices, house rental and hotel operations					
26. PT Patra Jasa	1975	252,598	236,119	229,394	90,570
Health services and hospital operations					
27. PT Pertamina Bina Medika	1997	109,326	105,743	111,006	100,083
Insurance services					
28. PT Asuransi Tugu Pratama Indonesia Tbk (formerly PT Tugu Pratama Indonesia) ("ATPI") **)	1981	966,584	923,376	836,387	662,347
Refineries					
29. PT Kilang Pertamina Internasional	2017	1,751	1,836	738	-
Liquified Natural Gas ("LNG")					
30. PT Nusantara Regas (Note 4b)	2010	276,029	240,817	277,438	272,925

*) Effective liquidation on February 28, 2019.
**) Deduction in the effective percentage of ownership in ATPI due to the issuance of new equity shares by ATPI in 2018.

ii. Associates

The directly owned associates as of March 31, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PPT Energy Trading Co., Ltd.	50.00%	Marketing services
2. PT Trans-Pacific Petrochemical Indotama	48.59%	Processing and sale of oil and gas products and services

The indirectly owned associates as of March 31, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PT Donggi Senoro LNG	29.00%	LNG Processing
2. PT Asuransi Samsung Tugu	19.50%	Insurance
3. Seplat Petroleum Development Company Plc, ("Seplat") Nigeria	21.37%	Oil and gas exploration and production
4. PT Gas Energi Jambi	22.78%	Trasport and distribution of natural gas

1. GENERAL (continued)

b. Subsidiaries, associates and joint arrangements (continued)

iii. Joint arrangements

The indirectly owned joint ventures as of March 31, 2019, are as follows:

Associates	Percentage of ownership	Nature of business
1. PT Patra SK	35.00%	Lube Base Oil ("LBO") processing
2. PT Perta-Samtan Gas	66.00%	LNG processing
3. PT Perta Daya Gas	65.00%	LNG regasification
4. PT Indo Thai Trading	51.00%	Petrochemical trading
5. PT Pertamina Rosneft Pengolahan dan dan Petrokimia	55.00%	Development of Petroleum and Petrochemical refineries
6. PT Transportasi Gas Indonesia ("Transgasindo")	59.87%	Transport of natural gas via transmission pipes
7. PT Permata Karya Jasa ("Perkasa")	60.00%	Workshop services, guidance, distribution of labor services Indonesia

PT Pertamina Rosneft Pengolahan dan Petrokimia ("PRPP") was established by Notarial Deed No. 13 dated November 28, 2017 of Mina NG, SH., M.KN., PRPP's Deed of Establishment was approved by the Minister of Justice and Human Rights through letter No. AHU-0053838.AH.01.01.Year 2017 dated November 28, 2017.

As of January 24, 2018, based on amendment of the Articles of Association of Perkasa, the Group no longer possesed control over Perkasa. As a result, the Group recognized investment in Perkasa as an investment in joint venture.

On April 11, 2018, the Company has control over PT Nusantara Regas. Previously, the Company recognized investment in PT Nusantara Regas as an investment in joint venture (Note 4b).

The indirectly owned joint operation as of March 31, 2019, is as follows:

Associates	Percentage of ownership	Nature of business
1. Natuna 2 B.V., Belanda	50.00%	Exploration and production

The Group considered the existence of substantive participating rights held by the non-controlling shareholders of PT Perta-Samtan Gas, PT Perta Daya Gas, PT Indo Thai Trading and PT Pertamina Rosneft Pengolahan dan Petrokimia which provide such shareholders with joint control over significant financial and operating policies. With respect to non-controlling rights, the Group does not have control over the significant financial and operating policies of PT Perta-Samtan Gas, PT Perta Daya Gas, PT Indo Thai Trading and PT Pertamina Rosneft Pengolahan dan Petrokimia even though the Group has more than 50% of share ownership.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a. Basis of preparation of the consolidated financial statements

The accounting and financial reporting policies adopted by the Group conform to the Indonesian financial accounting standards, which are based on Indonesian Statements of Financial Accounting Standards ("SFAS"). The accounting policies were applied consistently in the preparation of the consolidated financial statements as of March 31, 2019, and December 31, 2018, 2017, and 2016 and the three-month periods ended March 31, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016 by the Group.

The consolidated financial statements, except consolidated statement of cash flows have been prepared on the accrual basis and the measurement basis used is historical cost, except for certain accounts which requires different measurement as disclosed on each account's accounting policies.

The consolidated statements of cash flows have been prepared based on the direct method by classifying the cash flows into operating, investing and financing activities.

The consolidated financial statements are presented in thousands of US Dollars (US$), which is also the Group's functional currency, unless otherwise stated.

b. Change in accounting policies and disclosure

i. The adoption of these new/revised standards and interpretations did not result in substantial changes to the Group's accounting policies and had no material effect on the amounts reported in the consolidated financial statements

The following new standards, amendments to existing standards and interpretations have been published and are mandatory for the first time adoption for the Group's financial year beginning January 1, 2019 or later periods. The Group has adopted them, but they have no significant impact to the Group's current business:

- ISAK 33: Foreign Currency Transaction and Advance Consideration.
- ISAK 34: Uncertainty in the Treatment of Income Tax.
- Amendments to SFAS 24: Employee Benefits.
- SFAS 22 (2018 improvement): Business Combination.
- SFAS 26 (2018 improvement): Borrowing cost.
- SFAS 46 (2018 improvement): Income Tax.
- SFAS 66 (2018 improvement): Joint Arrangement.

ii. New standards, amendments and interpretations issued but not yet effective

The following are several accounting standards issued by the Indonesian Financial Accounting Standards Board ("DSAK") that are considered relevant to the financial reporting of the Group but not yet effective for consolidated financial statements as of March 31, 2019, and December 31, 2018, 2017, and 2016 and the three-month periods ended March 31, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016:

Effective January 1, 2020

- Amendments to SFAS 15: Investment in Associates and Joint Ventures, this amendments stipulates that the entity also applies SFAS 71 to financial instruments in associates or joint ventures where the equity method is not applied. This includes long-term interests which substantially form part of the entity's net investment in associates or joint ventures.
- Amendments to SFAS 62: Insurance Contracts, which allow those who meet certain criteria to apply a temporary exemption from SFAS 71 (Deferral Approach) or choose to apply a layered approach (Overlay Approach) to a defined financial asset.
- SFAS 71: Financial Instruments, which regulates the classification and measurement of financial instruments based on the characteristics of the contractual cash flows and the entity's business model; the expectation credit loss method for impairment that produces information that is more timely, relevant and understood by users of financial statements; accounting for hedges that reflects entity risk management is better by introducing more general requirements based on management considerations.
- SFAS 72: Revenue from Contracts with Customers which sets out a comprehensive framework to determine how, when and how much revenue can be recognized.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

b. Change in accounting policies and disclosure (continued)

ii. New standards, amendments and interpretations issued but not yet effective (continued)

- SFAS 73: Leases, with early adoption permitted specifically for entities that have implemented SFAS 72 which establishes the principle of recognition, measurement, presentation and disclosure of leases by introducing a single accounting model especially for tenants. This SFAS establishes the principle of recognizing, measuring, presenting, and disclosing leases by introducing a single accounting model by requiring right-of-use assets and lease liabilities. There are 2 optional exceptions in the recognition of lease assets and liabilities, namely for: (i) short-term leases and (ii) leases for low value underlying assets.

- Amendment of SFAS 71: Financial Instruments regarding prepayment features with negative compensation which regulates that financial assets with prepayment features that can result to negative compensation meets qualification as contractual cashflows that are solely payments of principal and interest.

- Amendement of SFAS 1: Presentation of Financial Statements and SFAS 25 : Accounting Policies, Changes in accouting estimates and errors which clarifies the defenition of material with the aim of harmonizing the definition used in the conceptual framework and some relevant SFASes.

The Group is currently evaluating and has not yet determined the effects of these accounting standards on its Consolidated Financial Statements.

c. Principles of consolidation

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as described in Note 1b.

Subsidiaries are entities over which the Group has control. The Group controls an entity when the Group is exposed or has rights to variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity.

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the Subsidiary and ceases when the Group loses control of the subsidiary.

A change in the ownership interest of a Subsidiary, without a loss of control, is accounted for as an equity transaction.

If the Group losses control over a Subsidiary, it derecognizes the related assets (including goodwill), liabilities, non-controlling interest (”NCI”) and other components of equity while any resulting gain or loss is recognized in profit or loss. Any investment retained is recognized at fair value.

The consolidated financial statements have been prepared using the same accounting policies for transactions and other events in similar circumstances. If a member of the Group uses accounting policies other than those adopted for transactions and events in similar circumstances, appropriate adjustments are made to its financial statements in preparing the consolidated financial statements.

All intercompany accounts and transactions between the Company and its Subsidiaries have been eliminated to reflect the financial position and the results of operations of the Group as one business entity.

NCI represents the portion of the profit or loss and net assets of the Subsidiaries attributable to equity interests that are not owned directly or indirectly by the Company, which are presented in the consolidated statement of profit or loss and other comprehensive income and under the equity section of the consolidated statement of financial position, respectively, separately from the corresponding portion attributable to the equity holders of the parent company.

Profit or loss and each component of other comprehensive income (“OCI”) are attributed to the equity holders of the parent of the Group and to the NCI, even if this results in the NCI having a deficit balance.

For consolidation purpose of subsidiaries using currency other than US Dollar as functional currency, assets and liabilities are translated using the Bank of Indonesia middle rate at the end of reporting period. On the other hand, revenue and expenses are translated using the average Bank of Indonesia middle rate during the profit or loss period.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

c. Principles of consolidation (continued)

The difference arising from the translation of those subsidiaries' financial statements into the US Dollar is presented as "Other comprehensive income - Differences arising from translation of financial statements" account as part of other equity components in the equity section of the consolidated statements of financial position.

d. Business combinations

Business combinations are accounted using the acquisition method as stipulated in SFAS 22 (Revised 2015). The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any NCI in the acquiree. For each business combination, the acquirer measures the NCI in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Transaction costs incurred are directly expensed and included in "Selling, General and Administrative Expenses".

When the Group acquires a business, it assesses the financial assets acquired and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances, and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date and any resulting gain or loss is recognized in profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognized at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration which is deemed to be an asset or liability will be recognized in accordance with SFAS No. 55 (Revised 2014) either in profit or loss or as other comprehensive income. If the contingent consideration is classified as equity, it should not be remeasured until it is finally settled within equity.

At acquisition date, goodwill is initially measured at cost being the excess of the aggregate of the consideration transferred and the amount recognized for NCI over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the Subsidiary acquired, the difference is recognized in profit or loss. Afterwards, impairment test on goodwill will be examined at the end of every subsequent period.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is allocated from the acquisition date to each of the Group's cash-generating units ("CGU") that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquirer are assigned to those CGUs.

Where goodwill forms part of a CGU and part of the operation within that CGU is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

In accordance with the provision of SFAS No. 22 (Revised 2015), if the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group shall report in its consolidated financial statements provisional amounts for the items for which the accounting is incomplete. During the measurement period, the Group shall retrospectively adjust the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date and, if known, would have affected the measurement of the amounts recognized as of that date.

The Company classified its investment in PT Badak Natural Gas Liquefaction ("Badak NGL") as available-for-sale financial asset at cost because the Company, in substance, does not control those companies as its operations are controlled by the natural gas producers. These investments are measured at cost since their fair values are not reliably measurable.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

e. Business combination under common control

Business combination transaction under common control, in the form of transfer of business within the framework of reorganization of entities under the same business group is not a change of ownership in economic substance, therefore it would not result in a gain or loss for the group as a whole or to the individual entity within the same group, therefore the transactions are recorded using the pooling-of-interests method.

The entity that disposed and received the business records the difference between the consideration received/transferred and the carrying amount of the disposed business/carrying amount of any business combination transaction in equity and presents it in “Additional Paid-in Capital” account.

In applying the pooling-of-interests method, the components of the financial statements for the period during which the business combination occurred and for other periods presented for comparison purposes are presented in such a manner as if the combination has already occurred since the beginning of the period in which the entities were under common control.

f. Related party transactions

The Company enters into transactions with related parties as defined in SFAS 7 (Revised 2015): Related Party Disclosures. All significant transactions and balances with related parties are disclosed in the notes to these consolidated financial statements.

g. Cash and cash equivalents

Cash and cash equivalents are cash on hand, cash in banks, and time deposits with maturity periods of three months or less at the time of placement and which are not used as collateral or are not restricted.

For the purpose of the consolidated statement of cash flows, cash and cash equivalents are presented net of overdrafts.

Cash and cash equivalents which are restricted for repayment of currently maturing obligations are presented as restricted cash under the current assets section, while cash and cash equivalents which are restricted to repay obligations maturing after one year from the date of consolidated statement of financial position are presented as part of other non-current assets.

h. Financial instruments

i. Financial assets

Initial recognition

Financial assets are classified as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets, or as derivatives designated as hedging instruments in an effective hedge. The classification depends on the nature and purpose for which the asset was acquired and is determined at the time of initial recognition.

Financial assets are recognized initially at fair value, and in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are added to the fair value.

Subsequent measurement

The subsequent measurement of financial assets depends on their classification as follows:

i. Financial assets at fair value through profit or loss
Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss.

ii. Loans and receivables
Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

i. Financial assets (continued)

Subsequent measurement (continued)

iii. Available-for-sale (“AFS”) financial assets
AFS financial assets are non-derivative financial assets that are designated as available-for-sale or are not classified in any of the two preceding categories. After initial measurement, AFS financial assets are measured at fair value with unrealized gains or losses recognized in equity until the investment is derecognized. At that time, the cumulative gain or loss previously recognized in equity is reclassified to the consolidated statement of profit or loss and other comprehensive income as a reclassification adjustment.

iv. Held-to-maturity investments
Non-derivative financial assets with fixed payments, and fixed liabilities and maturity liabilities are classified as held-to-maturity when the Group has positive intentions and capabilities to maintain them until maturity. After initial measurement, held-to-maturity investments are measured at amortized cost using the Effective Interest Rate ("EIR") method. Amortization of EIR is recognized as financial income in profit or loss. Losses arising from a decrease in value are recognized in profit or loss as a financial expense.

Impairment of financial assets

Assets carried at amortized cost

The Group assesses, at the end of each reporting period, whether there is objective evidence that a financial asset or group of financial assets is impaired.

The criteria that the Group uses to determine that there is objective evidence of an impairment loss include:
i. default or delinquency in payments by the debtor;
ii. significant financial difficulty of the debtor;
iii. a breach of contract, such as a default or delinquency in interest or principal payments;
iv. the lenders, for economic or legal reasons relating to the borrower’s financial difficulty, granting to the borrower a concession that the lenders would not otherwise consider;
v. the probability that the debtor will enter bankruptcy or other financial reorganization;
vi. the disappearance of an active market for that financial asset because of financial difficulties; or
vii. observable data indicating that there is a measurable decrease in the estimated future cash flows from a portfolio of financial assets since the initial recognition of those assets, although the decrease cannot be traced yet to the individual financial assets in the portfolio, including:
    1. adverse changes in the payment status of borrowers in the portfolio; and
    2. national or local economic conditions that correlate with defaults on the assets in the portfolio.

If there is an objective evidence that an impairment loss has occurred, the amount of loss is measured as the difference between the asset’s carrying amount and the present value of estimated future cash flows (excluding future credit losses that have not been incurred) discounted at the financial asset’s original EIR. The carrying amount of the asset is reduced either directly or through the use of a provision account. The amount of the loss is recognized in the profit or loss.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized (such as an improvement in the debtor’s credit rating), the previously recognized impairment loss will be reversed either directly or by adjusting the provision account. The reversal amount is recognized in the profit or loss and the amount cannot exceed what the amortized cost would have been had the impairment not been recognized at the date the impairment was reversed.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

i. Financial assets (continued)

Assets classified as available-for-sale

When a decline in the fair value of an available-for-sale financial asset has been recognized directly in equity and the decline is significant and prolonged or when there is objective evidence that the assets were impaired, the cumulative loss that had been recognized in equity will be reclassified from equity to the profit or loss even though the financial asset has not been derecognized. The amount of the cumulative loss that is reclassified from equity to the profit or loss is the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in the profit or loss.

The impairment loss recognized in the profit or loss on equity instrument cannot be reversed through the profit or loss. Increases in fair value subsequent to the impairment are recognized in OCI.

Derecognition

A financial asset, or where applicable, a part of a financial asset or part of a group of similar financial assets, is derecognized when:

(i) The contractual rights to receive cash flows from the asset have expired; or
(ii) The Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a “pass-through” arrangement, and either (a) the Group has transferred substantially all the risks and rewards of the financial asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

ii. Financial liabilities

Initial recognition

Financial liabilities are classified as financial liabilities at fair value through profit or loss and other financial liabilities that are not held for trading or not designated at fair value through profit or loss. The Group determines the classification of its financial liabilities at initial recognition.

Financial liabilities are recognized initially at fair value and, in the case of financial liabilities recognized at amortized cost, include directly attributable transaction costs.

The Group’s financial liabilities which are classified as other financial liabilities include short-term loans, trade payables, due to the Government, accrued expenses, long-term liabilities, other payables, bonds payable, and other non-current payables.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

ii. Financial liabilities (continued)

Subsequent measurement

The measurement of financial liabilities depends on their classification as follows:

i. Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivative liabilities are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognized in the consolidated statement of profit or loss and other comprehensive income.

ii. Financial liabilities at amortized cost

After initial recognition, interest-bearing loans and borrowings are subsequently measured at cost using the EIR method. At the reporting date, the accrued interest is recorded separately from the respective principal loans as part of current liabilities. Gains and losses are recognized in the consolidated statement of profit or loss and other comprehensive income when the liabilities are derecognized as well as through the amortization process using the EIR method.

Derecognition

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognized in the consolidated statement of profit or loss and other comprehensive income.

A financial liability is derecognized when the obligation under the liability is discharged, or cancelled or has expired.

Effective interest rate (“EIR”) method

The EIR method is a method of calculating the amortized cost of a financial asset and of allocating interest income over the relevant period.

iii. Offsetting financial instruments

Financial assets and liabilities are offset and the net amount is reported in the consolidated statements of financial position, when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or to realize the asset and settle the liability simultaneously.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

h. Financial instruments (continued)

iv. Derivative financial instruments and hedge accounting

The Group uses derivative foreign currency forward and option contracts to hedge its foreign currency risks. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

The Company entered into forward and currency option contracts that are used as a hedge for the exposure to changes in cash flows relating to interest payments and bonds repayment due to changes in foreign exchange rates. Such forward and option contracts do not meet the criteria of hedge accounting.

i. Receivables

Trade and other receivables are initially recognized at fair value and are subsequently measured at amortized cost using the effective interest method, less provision for any impairment. If collection is expected in one year or less (or in the normal operating cycle of the business if longer), these receivables are classified as non-current assets.

j. Inventories

Crude oil and oil product inventories are recognized at the lower of cost or net realizable value.

Cost is determined based on the average method and comprises all costs of purchases, costs of conversion and other costs incurred in bringing the inventory to its present location and current condition.

The net realizable value of subsidized fuel products (“BBM”) are recognized at the lower of next month Government decreed price and the formula price.

The net realizable value of 3 kg LPG cylinders is the Aramco LPG contract price plus distribution costs and a margin (alpha), less the estimated costs of completion and the estimated costs necessary to make the sale.

Materials such as spare parts, chemicals and others are stated at average cost. Materials exclude obsolete, unusable and slow-moving materials which are recorded as part of other assets under the non-current assets section.

A provision for obsolete, unuseable and slow-moving materials is provided based on management’s analysis of the condition of such materials at the end of the year.

k. Prepayments and advances

Prepayments are amortized on a straight-line basis over the estimated beneficial periods of the prepayments.

l. Assets held for distribution to the Company

Assets held for distribution to the Company are recognized at the lower of carrying amount and fair value less costs to sell.

m. Long-term investments

i. Investments in associates

Associates are all entities over which the Group has significant influence but not control, generally accompanying a shareholding of between 20% and 50% of the voting rights. Investments in associates are accounted for using the equity method of accounting and are initially recognized at cost. The Group’s investment in associates includes goodwill identified on acquisition, net of any accumulated impairment loss.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

m. Long-term investments (continued)

i. Investments in associates (continued)

The Group's share of its associates' post-acquisition profits or losses is recognized in the profit or loss, and its share of post-acquisition movements in other comprehensive income is recognized in OCI.

Dilution gains and losses arising from investments in associates are recognized in the profit or loss.

ii. Investment property

Investment property consists of land and buildings held by the Group to earn rental income or for capital appreciation, or both, rather than for use in the production or supply of goods or services, administrative purposes or sale in the normal course of business.

An investment property is measured using the cost model that is stated at cost including transaction costs less accumulated depreciation and impairment losses, if any, except for land which is not depreciated. Such cost includes the cost of replacing part of the investment property, if the recognition criterias are satisfied, and excludes operating expenses involving the use of such property.

Building depreciation is computed using the straight-line method over the estimated useful lives of buildings ranging from 10 to 25 years.

An investment property is derecognized upon disposal or when such investment property is permanently withdrawn from use and no future economic benefits are expected from its disposal. Gains or losses arising from the derecognition or disposal of investment property are recognized in the profit or loss in the year such derecognition or disposal occurs.

Transfers to investment property are made when there is a change in use, evidenced by the end of owner-occupation or commencement of an operating lease to another party. Transfers from investment property are made when there is a change in use, evidenced by the commencement of owner-occupation.

For a transfer from investment property to owner-occupied property, the Group uses the cost method at the date of change in use. If owner-occupied property becomes an investment property, the Group recognized the investment property in accordance with the fixed asset policies the date of change in use.

n. Fixed assets

The Group applies accounting policy on fixed assets as stipulated in SFAS 16 (Revised 2015), as follows:

Direct ownership

Land is recognized at cost and not depreciated. Fixed assets are initially recognized at cost and subsequently, except for land, carried at cost less accumulated depreciation and any impairment losses.

Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The Group recognized significant repair and maintenance costs as fixed assets. The carrying amount of the replaced part is derecognized. All other repairs and maintenance are charged to the profit or loss during the financial period in which they are incurred.

Initial legal costs incurred to obtain legal rights are recognized as part of the acquisition cost of the land, and these costs are not depreciated. Costs related to renewal of land rights are recognized as intangible assets and amortized during the period of the land rights.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

n. Fixed assets (continued)

Fixed assets, except land, are depreciated using the straight-line method over their estimated useful lives as follows:

	Years
Tanks, pipeline installations and other equipment	5-25
Refineries	10-20
Buildings	5-25
Ships and aircrafts	6-25
Moveable assets	5-20
Major repairs and maintenance	3

At each financial year-end, the residual values, useful lives and methods of depreciation of assets are reviewed and adjusted prospectively, as appropriate.

When assets are retired or otherwise disposed of, their carrying values are eliminated from the consolidated financial statements, and the resulting gains and losses on the disposal of fixed assets are recognized in the profit or loss.

Assets under construction

Assets under construction represent costs for the construction and acquisition of fixed assets and other costs. These costs are transferred to the relevant fixed asset account when the construction is complete. Depreciation is charged from the date the assets are available for use.

o. Leases

The Group classifies leases based on the extent to which risks and rewards incidental to the ownership of a leased asset are vested upon the lessor or the lessee, and the substance of the transaction rather than the form of the contract, at the time of initial recognition.

Group as Lessee

i. A lease is classified as a finance lease if it transfers substantially all the risks and rewards incidental to ownership of the leased assets. Such leases are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant periodic rate of interest on the remaining balance of the liability. Finance charges are charged directly to profit or loss.

ii. A lease is classified as an operating lease if it does not transfer substantially all the risks and rewards incidental to ownership of the leased asset. Accordingly, the related lease payments are recognized in profit or loss on a straight-line basis over the lease term.

Group as Lessor

Leases in which the group does not transfer substantially all the risks and rewards of ownership of an asset are classified as operating leases initial direct costs in caused in negotiating and arranging an operating leases are added to the carrying amount of the leased asset and recognized over the lease term on the same basis of rental income. Contingent rents are recognized as revenues in the period in which they are earned.

p. Oil and gas and geothermal properties

i. Exploration and evaluation assets

Oil and natural gas, as well as geothermal exploration and evaluation expenditures, are accounted for using the successful efforts method of accounting. Costs are accumulated on a field by field basis.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

p. Oil and gas and geothermal properties (continued)

i. Exploration and evaluation assets (continued)

Geological and geophysical costs are expensed as incurred.

Costs to acquire rights to explore for and produce oil and gas are recorded as unproved property acquisition costs for properties where proved reserves have not yet been discovered, or proved property acquisition costs if proved reserves have been discovered.

The costs of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells are capitalized as part of assets under construction - exploratory and evaluation wells, within oil and gas properties pending determination of whether the wells have found proved reserves. If the well has not found proved reserves, the capitalized costs of drilling the well are then charged to profit or loss as a dry hole expense.

Afterwards, exploration and evaluation assets are reclassified from exploration and evaluation assets when evaluation procedures have been completed. Exploration and evaluation assets for which commercially-viable reserves have been identified are reclassified to development assets. Exploration and evaluation assets are tested for impairment immediately prior to reclassification out of exploration and evaluation assets.

ii. Development assets

The costs of drilling development wells including the costs of drilling unsuccessful development wells and development-type stratigraphic wells are capitalized as part of assets under construction of development wells until drilling is completed. When the development well is completed on a specific field, it is transferred to the production wells.

iii. Production assets

Production assets are aggregated exploration and evaluation assets and development expenditures associated with the producing wells. Production assets are depleted using a unit-of-production method on the basis of proved developed reserves, from the date of commercial production of the respective field.

iv. Other oil and gas and geothermal assets

Other oil and gas and geothermal properties are depreciated using the straight-line method over the lesser of their estimated useful lives or the term of the relevant Production Sharing Contract (“PSC”) are as follows:

	Years
Installations	3-30
LPG plants	10-20
Buildings	5-30
Moveable assets	2-27
Geothermal wells	10-20

Land and land rights are stated at cost and are not amortized.

The useful lives and methods of depreciation of assets are reviewed, and adjusted prospectively if appropriate, at least at each financial year-end. The effects of any revisions are recognized in profit or loss, when the changes arise.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

p. Oil and gas and geothermal properties (continued)

iv. Other oil & gas and geothermal assets (continued)

Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of the replaced part is derecognized. All other repairs and maintenance are charged to the profit or loss during the financial period in which they are incurred.

The accumulated costs of the construction, installation or completion of buildings, plant and infrastructure facilities such as platforms and pipelines are capitalized as assets under construction. These costs are reclassified to the relevant fixed asset accounts when the construction or installation is ready for use. Depreciation is charged from that date.

q. Provision for decommissioning and site restoration

The provision for decommissioning and site restoration provides for the legal obligations associated with the retirement of oil and gas properties including the production facilities that result from the acquisition, construction or development and/or normal operation of such assets. The retirements of such assets, other than temporary suspension of use, are removed from service including sale, abandonment, recycling or disposal in some other manner.

These obligations are recognized as liabilities when a constructive obligation with respect to the retirement of an asset is incurred. An asset retirement cost equivalent to these liabilities is capitalized as part of the related asset's carrying value and is subsequently depreciated or depleted over the asset's useful life. These obligations are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation.

Provision for environmental issues that may not involve the retirement of an asset, where the Group is a responsible party, is recognized when:

- the Group has a present legal or constructive obligation as a result of past events;
- it is probable that an outflow of resources will be required to settle the obligation; and
- the amount has been reliably estimated.

Asset retirement obligations for downstream facilities generally become firm at the time the facilities are permanently shutdown and dismantled. However, these facilities have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligation. The Group performs periodic reviews of its downstream assets for any changes in facts and circumstances that might require recognition of asset retirement obligations.

r. Revenue and expense recognition

i. Revenue

Revenue from the production of crude oil and natural gas are recognized on the basis of the provisional entitlements method at the point of lifting. Differences between the actual liftings of crude oil and natural gas result in a receivable when final entitlements exceed liftings of crude oil and gas (underlifting position) and in a payable when lifting of crude oil and natural gas exceed final entitlements (overlifting position). Underlifting and overlifting volumes are valued based on the annual weighted average Indonesian Crude Price ("ICP") (for crude oil) and price as determined in the respective Sale and Purchase Contract (for natural gas).

The Company recognizes subsidy revenue as it sells the subsidy products and becomes entitled to the subsidy.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

r. Revenue and expense recognition (continued)

i. Revenue (continued)

Revenue from sales of goods and services is recognized when the significant risks and rewards of ownership of the goods are transferred to the buyer and when such services are performed, respectively.

Penalty income from overdue receivables from BBM sales is recognized when the Company and its customers agree on the amount of the penalties and there is evidence that the customers have committed to pay the penalties.

Revenues from gas distribution and toll fees from gas transmission are recognized when the gas is distributed or transmitted to the customers based on the gas meter readings.

Revenue arising from the operation of the asset and pipeline transmission is recognized after the service is rendered and is measured based on the unit of gas which has been transported during such period.

The cost and revenue involving sales of electricity among PGE, geothermal contractors and PT Perusahaan Listrik Negara (Persero) (“PLN”) are recorded based on Energy Sales Contracts under a Joint Operating Contracts (“JOC”). The contracts stipulate that the sale of electricity from the JOC contractors to PLN is to be made through PGE in the same amount of the purchase costs as the electricity from the JOCs.

Excess and/or shortfall of revenue from differences of formula retail selling price and Government’s stipulated selling price (“Disparity of Selling Price”) of certain type of fuel (“JBT”) Diesel Fuel and special fuel assignment ("JBKP") Premium are recognized in the period when sale of JBT Diesel Fuel and JBKP Premium occurs as long as the settlement and/or collectability of such Disparity of Selling Prices is certain at the completion date of the financial statements.

The Company records such excess and/or shortfall of revenue from the Disparity of Selling Prices in revenue from other operating activities account because it is part of the Company’s operations.

Deferred revenue consist of:
- amounts billed and collected involving “take or pay” gas quantities, which will be recognized as revenue when the related gas quantities are delivered to customers or wen the contract expires.
- payment for rental and services charges received upfront.
- rental revenue that is received in advance.

ii. Expense

Expense is recognized when incurred on an accrual basis.

s. Pension plan and employee benefits

i. Pension obligations

Entities within the Group operate various pension schemes. The Group has both defined benefit and defined contribution plans. A defined contribution plan is a pension plan under which the Group pays fixed contributions into a separate entity. The Group has no legal or constructive obligations to pay further contributions if the fund does not hold sufficient assets to pay all employee the benefits relating to employee service in the current and prior years.

The Group is required to provide a minimum amount of pension benefit in accordance with Labour Law No. 13/2003 or the Group’s Collective Labour Agreement (“the CLA”), whichever is higher. Since the Labour Law or the CLA sets the formula for determining the minimum amount of pension benefits, in substance, pension plans under the Labour Law or the CLA represent defined benefit plans.

The liability recognized in the statement of financial position in respect of the defined benefit pension plans is the present value of the defined benefit obligation at the end of the reporting date less the fair value of plan assets.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

s. Pension plan and employee benefits (continued)

i. Pension obligations (continued)

The defined benefit obligation is calculated annually by independent actuaries using the projected unit credit method.

Expense charged to profit or loss includes current service costs, interest expense/income, past service cost and gains and losses on settlements. Gains or losses on the curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs.

Remeasurements arising from defined benefit retirement plans are recognized in OCI.

Termination benefits are payable when an employee's employment is terminated by the Group before the normal retirement date, or whenever an employee accepts voluntary redundancy in exchange for these benefits.

The Group recognizes the termination benefits at the earlier of the following dates: (a) when the Group can no longer withdraw the offer of those benefits; and (b) when the Group recognizes restructuring costs involving the payment of termination benefits.

ii. Other post-employment obligations

Companies within the Group provide "post retirement" healthcare benefits to their retired employees. This benefit is eligible for the employee that remains working up to retirement age and approaching a minimum service period. The expected cost of this benefit is accrued over the period of employment using the projected unit credit method. This obligation is valued annually by independent qualified actuaries.

t. Transactions and balances in non-US Dollar denomination

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the functional currency).

Non-US Dollar currency transactions are translated into US Dollar using the exchange rates prevailing at the dates of the transactions. At each reporting date, monetary assets and liabilities denominated in non-US Dollar currency are translated into US Dollar using the closing exchange rate. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the profit or loss, except when deferred in equity as qualifying cash flows hedges and qualifying net investment hedges.

For domestic and foreign subsidiaries that are not integral to the Company's operations and for which the functional currency is not the US Dollar, the assets and liabilities are translated into US Dollars at the exchange rates prevailing at the date of statement of financial position.

The exchange rates used as of March 31, 2019 and December 31, 2018, 2017, and 2016 were as follows (full amount):

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
1,000 Rupiah/US Dollar	0.07	0.07	0.07	0.07
Singapore Dollar/US Dollar	0.74	0.73	0.75	0.69
100 Japanese Yen/US Dollar	0.90	0.91	0.89	0.86
Hong Kong Dollar/US Dollar	0.13	0.13	0.13	0.13
Euro/US Dollar	1.12	1.14	1.19	1.05
Malaysian Ringgit/US Dollar	0.25	0.24	0.25	0.22
Algeria Dinar/US Dollar	0.01	0.01	0.01	0.01

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

u. Income tax

Current income tax

Current tax assets and liabilities are measured at the amount expected to be refunded from or paid to the taxation authority. The tax rates and tax regulations used to calculate these amounts are those that have been enacted or substantively enacted at the reporting date in the country where the Group operates and produce taxable income.

Interest and penalties are presented as part of income or other operating expenses because they are not considered as part of the income tax expense.

The Group periodically evaluates positions reported in Annual Tax Returns ("SPT") in connection with situations in which application of certain tax regulation are subject to interpretation. Where appropriate, the Group establishes provision based on the amounts expected to be paid to the tax authorities including consideration of tax court and supreme court decision in case of Group's appeal process.

Corrections to taxation obligations are recorded when an assessment is received, or for assessment amounts appealed against by the Group, when: (1) the result of the appeal is determined, unless there is significant uncertainty as to the outcome of such an appeal, in which event the impact of the amendment of tax obligations based on an assessment is recognized at the time of making such appeal, or (2) at the time based on knowledge of developments in similar cases involving matters appealed, in rulings by the Tax Court or the Supreme Court, where a positive appeal outcome is adjudged to be significantly uncertain, in which event the impact of an amendment of tax obligations is recognized based on the assessment amounts appealed.

In income tax calculation, the Company recognizes revenue from Disparity of Selling Price in the amount of the value of the receivables before adjusting for fair value (Note 9a). Difference in value of receivables with fair value is recognized as deferred tax assets. Recovery from adjusting the fair value of receivables in subsequent years will be recorded as interest income. The interest income is not recognized as an object of income tax but as a reversal of previously deferred tax assets.

Deferred tax

Deferred tax is recognized using the liability method for temporary differences between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date.

Deferred tax liabilities are recognized for all taxable temporary differences, except:

i. deferred tax liabilities that occur from the initial recognition of goodwill or from assets or liabilities from transactions that are not business combination transactions, and at the time of the transaction do not affect accounting profit and taxable/taxable income;
ii. from taxable temporary differences in investments in subsidiaries, associated companies and interests in joint arrangements, which when reversed can be controlled and it is probable that the temporary differences will not be reversed in the near future.

Deferred tax assets are recognized for all deductible temporary differences, unused tax credit balances and accumulated unused tax losses. Deferred tax assets are recognized to the extent that it is probable that the amount of taxable income will be sufficient to be compensated with deductible temporary differences, and the application of unused tax credits and taxable accumulated losses that can be used, except:

i. if deferred tax assets arise from the initial recognition of an asset or liability in a transaction that is not a business combination transaction and does not affect the accounting profit or taxable income/tax loss; or

ii. from temporary differences that can be deducted from investments in subsidiaries, associated companies and interests in joint arrangements, deferred tax assets are only recognized if it is probable that the temporary differences will not be reversed in the near future and taxable profits can be compensated by the temporary difference.

The carrying amount of deferred tax assets is reviewed at each reporting date and is reduced if the taxable income may not be sufficient to compensate for part or all of the benefits of the deferred tax asset. Deferred tax assets that are not recognized are reviewed at each reporting date and will be recognized if it is probable that future taxable profits will be available for recovery.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

u. Income tax (continued)

Deferred Tax (continued)

Deferred tax assets and liabilities are measured using the tax rate that is expected to apply to the year when the asset is recovered or the liability is settled based on the tax rates and applicable tax regulations or substantively enacted at the reporting date.

Deferred tax assets and liabilities related to PSC activities are calculated using the tax rate that applies to the effective date of the PSC or renewal date or date of change in the PSC.

Deferred tax on goods recognized outside of profit or loss is recognized outside of profit or loss. Estimated deferred tax is recognized to correlate with underlying transactions in both the OCI and directly in equity.

Value Added Tax ("VAT")

Revenues, expenses and assets are recognized net of the amount of VAT except:

i. VAT that arises from the purchase of an asset or service that cannot be credited by the tax office, in which case the VAT is recognized as part of the acquisition cost of the asset or as part of the items applied for expenses; and

ii. Receivables and payables presented include the amount of VAT.

VAT on subsidies and/or Disparity of Selling Price will be recorded by the Company when submitting payments for subsidies and/or price differences to the Directorate General of Budget.

Final Tax

In accordance with taxation regulations in Indonesia, final tax is applied to the gross value of the transactions, even when the parties carrying the transactions recognizing losses.

Referring to revised PSAK No. 46 (Revised 2014), final tax is no longer governed by PSAK No. 46. Therefore, the Company has decided to present all of the final tax arising from interest income which subject to final tax as separate line item.

v. Segment information

An operating segment is a component of an enterprise:
a. that engages in business activities from which it may earn revenues and incur expenses (including revenue and expenses related to the transactions with different components within the same entity);
b. whose operating results are regularly reviewed by the enterprise's chief operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and
c. for which discrete financial information is available.

w. Impairment of non-financial assets

Assets that have an indefinite useful life - for example, goodwill or intangible assets not ready for use - are not subject to amortization and are tested annually for impairment.

Assets that are subject to amortization or depreciation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognized in the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (Cash-Generating Units or CGUs). Non-financial assets other than goodwill that suffer an impairment are reviewed for possible reversal of the impairment at each reporting date.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

x. Bond issue costs

Bond issue costs are presented as a deduction from bonds payable as part of non-current liabilities in the consolidated statement of financial position.

The difference between net proceeds and nominal value represents a discount which is amortized using the EIR method over the term of the bond.

y. Joint arrangements

The Group is a party to a joint arrangement when there is a contractual arrangement that confers joint control over the relevant activities of the arrangement to the Group and at least one other party. Joint control is assessed under the same principles as control over subsidiaries.

The Group classifies its interests in joint arrangements as either:
a. Joint ventures: where the Group has rights to only the net assets of the joint arrangement.
b. Joint operations: where the Group has both the rights to assets and obligations for the liabilities of the joint arrangement.

In assessing the classification of interests in joint arrangements, the Group considers:
a. the structure of the joint arrangement;
b. the legal form of joint arrangements structured through a separate vehicle;
c. the contractual terms of the joint arrangement agreement;
d. any other facts and circumstances (including any other contractual arrangements).

The Group recognizes its interest in joint venture using equity method.

Any premium paid for an investment in a joint venture above the fair value of the Group's share of the identifiable assets, liabilities and contingent liabilities acquired is capitalized and included in the carrying amount of the investment in joint venture. Where there is objective evidence that the investment in a joint venture has been impaired, the carrying amount of the investment is tested for impairment in the same way as non-financial assets.

The Group accounts for its interests in joint operations by recognizing its share of assets, liabilities, revenues and expenses in accordance with its contractually conferred rights and obligations.

z. Share capital

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issuance of new shares are shown in equity as a deduction, net of tax, from the proceeds.

aa. Dividends

Dividend distribution to the shareholders is recognized as a liability and deducted from equity in the Group consolidated financial statements in the period in which the dividends are declared.

ab. Borrowing costs

Borrowing costs are interest and exchange differences on foreign currency denominated borrowings and other costs (amortization of discounts/premiums on borrowings, etc) incurred in connection with the borrowing of funds.

Borrowing costs which are directly attributable to the acquisition, construction, or production of qualifying assets are capitalized as part of the acquisition cost of the qualifying assets. Other borrowing costs are recognized as expense in the period in which they are incurred.

The Group ceases capitalizing borrowing costs when substantially all the activities necessary to prepare the qualifying asset for its intended use or sale are complete.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

ac. Fair value measurement

The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:
- in the principal market for the asset or liability or;
- in the absence of a principal market, in the most advantageous market for the asset or liability.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy as follows:
- Level 1 - quoted (unadjusted) market prices in active markets for identical assets or liabilities;
- Level 2 - valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable; and
- Level 3 - valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

ad. Completion of consolidated financial statements

The Group's consolidated financial statements have been completed and authorized to be issued by the Company's Directors on July 15, 2019.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS

In the application of the Group's accounting policies, which are described in Note 2 to the consolidated financial statements, management is required to make estimates, judgements and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources.

These estimates, judgements and assumptions are based on historical experience and other factors that are considered to be relevant.

a. Judgements

The following judgements are made by management in the process of applying the Group's accounting policies:

i. Exploration and evaluation expenditures

The Group's accounting policies for exploration and evaluation expenditures result in certain items of expenditure being capitalized for an area of interest where it is considered likely to be recoverable by future exploitation or sale or where the activities have not reached a stage which permits a reasonable assessment of the existence of reserves. This policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established.

ii. Development expenditures

Development activities commence after a project is sanctioned by the appropriate level of management. Judgement is applied by management in determining when a project is economically viable.

iii. Uncertain tax exposure

Based on the tax regulations currently enacted, the management assessed if the amounts recorded under claim for tax refund are recoverable and refundable from the Tax Office. Further, the management also assessed possible liability that might arise from the tax assessment under objection.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

a. Judgements (continued)

iii. Uncertain tax exposure (continued)

Significant judgement is involved in determining the provision for corporate income tax and other taxes on certain transactions. Uncertainties exist with respect to the interpretation of complex tax regulations and the amount and timing of future taxable income. The Group makes an analysis of all tax positions related to income taxes to determine if a tax liability for unrecognized tax benefit should be recognized.

iv. Recognition of disparity of selling price of JBT diesel fuel and JBKP premium

Based on Presidential Regulation No. 43 Year 2018 dated May 25, 2018 regarding Amendment to Presidential Regulation No. 191 Year 2014 regarding Provision, Distribution and HJE Fuel Oil, it is stated that in the event, based on the Audit Board of the Republic of Indonesia (BPK)'s audit results in 1 (one) fiscal year, there are the excess and/or shortfall of revenue of the assigned business entity as a result of government's stipulated sellling price of fuel oil, the Minister of Finance, after coordinating with the Minister of Energy and Mineral Resources (the "MoEMR") and the Minister of State-Owned Enterprises (the "MoSOE"), establishes the policy for excess and/or shortfall of revenue of the business entity.

Management's confidence to record excess and/or shortfall of revenue from the Disparity of Selling Price in the period when sale of JBT Diesel Fuel and JBKP Premium occurs, if the settlement and/or collectability of such Disparity of Selling Price is certain, which are mainly supported if, the Company has transferred all risks and rewards of JBT Diesel Fuel and JBKP Premium to consumers across Indonesia areas and the Company retains neither continuing managerial involvement and effective control over JBT Diesel Fuel and JBKP Premium when the sale occurred and the BPK's audit results on the Disparity of Selling Price received by the Company. In respect of the shortfall of revenue from the Disparity of Selling Price, the collectabilty of revenue from the Disparity of Selling Price is certain when the Decision Letter from the Minister of Finance ("Decision Letter") has been received by the Company prior to the completion of the financial statements. The Company records such excess and/or shortfall of revenue from the Disparity of Selling Price in revenue from other operating activities account because it is part of the Company's operations.

b. Estimates and assumptions

The key assumptions regarding the future and other key sources of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial period are disclosed below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared.

i. Impairment of non-financial assets

In accordance with the Group's accounting policy, each asset or CGU is evaluated every reporting period to determine whether there are any indications of impairment.

The determination of fair value and value in use requires management to make estimates and assumptions about expected production and sales volumes, commodity prices (considering current and historical prices, price trends and related factors), reserves, operating costs, decommissioning and site restoration cost, and future capital expenditure. These estimates and assumptions are subject to risk and uncertainty; hence there is a possibility that changes in circumstances will alter these projections, which may have an impact on the recoverable amount of the assets.

ii. Reserves estimates

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves include:

(i) proved developed reserves: amounts of hydrocarbons that are expected to be retrieved through existing wells, facilities and operating methods; and
(ii) proved undeveloped reserves: amounts of hydrocarbons that are expected to be retrieved following new drilling, facilities and operating methods.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

b. Estimates and assumptions (continued)

ii. Reserves estimates (continued)

The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables such as: the quality of available geological, technical and economic data, results of drilling, testing and production after the date of the estimates, the production performance of the reservoirs, production techniques, projecting future rates of production, the anticipated cost and timing of development expenditures, the availability for commercial market, anticipated commodity prices and exchange rates.

As the economic assumptions used to estimate reserves change from year to year, and additional geological data are generated during the course of operations, estimates of reserves may change from year to year. Changes in reported reserves may affect the Group's financial results and financial position in a number of ways, including:

i. Depreciation and amortization which are determined on a unit of production basis, or where the useful economic lives of assets change.
ii. Decommissioning, site restoration and environmental provision may change where changes in estimated reserves affect expectations about the timing or cost of these activities.
iii. The carrying value of deferred tax assets/liabilities may change due to changes in estimates of the likely recovery of the tax benefits.

The Group has established proven reserves based on the principle of Petroleum Resources Management System ("PRMS") 2018 starting from January 1, 2019 (previously based on PRMS 2007). The characteristics of the estimation uncertainty of natural reservoirs of oil and gas reserve may lead to changes in the estimated reserves due to the additional data obtained by the Group.

iii. Oil and gas properties

The Group applies the successful efforts method for its oil and natural gas exploration and evaluation activities.

For exploration and exploratory-type stratigraphic test wells, costs directly associated with the drilling of those wells are initially capitalized as assets under construction within oil and gas properties, pending determination of whether potentially economically viable oil and gas reserves have been discovered by the drilling effort.

Such estimates and assumptions may change as new information becomes available. If the well does not discover potentially economically viable oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense.

iv. Provision for the impairment of loans and receivables

Provision for the impairment of receivables is maintained at a level considered adequate to provide for potentially uncollectible receivables. The Group assesses specifically at each balance sheet date whether there is objective evidence that a financial asset is impaired (uncollectible).

The level of provision is based on past collection experience and other factors that may affect collectability.

Loans and receivables write-offs are based on management's decision that the financial assets are uncollectible or cannot be realized regardless of the actions taken.

v. Due from the Government

The Group recognizes amounts due from the Government for cost subsidies for certain fuel ("BBM") products and 3 kg LPG cylinders and marketing fees in relation to the Government's share of crude oil, natural gas and LNG. The Group makes an estimation of the amount due from the Government based on the actual delivery volume parameter and rates based on government regulations. The amount of subsidies is subject to audit and approval by the Audit Board of the Republic of Indonesia ("BPK"). The actual results may be different from the amounts recognized.

3. MANAGEMENT'S USE OF ESTIMATES, JUDGEMENTS AND ASSUMPTIONS (continued)

b. Estimates and Assumptions (continued)

vi. Depreciation, estimate of residual values and useful lives of fixed assets

The useful lives of the Group's investment properties and fixed assets are estimated based on the period over which the asset is expected to be available for use. Such estimation is based on a collective assessment of similar businesses, internal technical evaluations and experience with similar assets.

vii. Deferred tax assets

Deferred tax assets are recognized only where it is considered more likely than not that they will be recovered, which is dependent on the generation of sufficient future taxable profits.

viii. Provision for decommissioning and site restoration

The Group is obliged to carry out future decommissioning of oil and gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations faced by the Group relate to the plugging and abandonment of wells and the removal and disposal of oil and gas platforms and pipelines in its contract area.

Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the related asset and could have a material impact on the Group's consolidated financial statements.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST

The Group has acquired and added participating interest through acquisition transactions or acquisitions of terminated blocks. The acquisition transactions were made in accordance with the Group's strategy to develop its upstream business i.e. to increase oil, gas and geothermal production and reserves, and to expand the business overseas. The summary of the Group's transactions during 2016 until March 31, 2019 is as follows:

Acquisition of shares	Working area	Area	Percentage of participation	Production	Owned by
Share acquisition Etablissements Maurel et Prom SA (M&P)	France	Canada, Colombia, Nigeria, Gabon, France, Italy, Tanzania, Namibia and Myanmar	72.65%	Oil and gas	PT Pertamina Internasional Eksplorasi dan Produksi

Acquisition of working area and interest	Working area	Area	Effective date of contract	Expiry date of contract	Percentage of Participation	Production	Contract period	Owned by
Acquisition of Working Area Kampar Block	Kampar Block	Riau	01/01/2016	31/12/2035	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area East Ambalat Block	East Ambalat Block	East Kalimantan	25/05/2016	24/05/2046	100%	Oil and gas	30 years	PT Pertamina Hulu Energi
Acquisition of Working Area Offshore North West Java	Offshore North West Java Block	North West Java	19/01/2017*	18/01/2037	90%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area Geothermal Gunung Lawu	Gunung Lawu	Central Java and East Java	30/01/2017	29/01/2054	100%	Geothermal	37 years	PT Pertamina Geothermal Energy and PT Pertamina Hulu Energi
Acquisition working interest in Jambaran Tiung Biru Unitization Field	EP Block and Cepu Block	Central Java-East Java	01/01/2018**	16/09/2035	91.93%	Gas	Until the end of PEPC's PSC	PT Pertamina EP Cepu
Acquisition of Working Area Attaka (unitization)	Attaka	East Kalimantan	01/01/2018	24/10/2018	100%	Oil and gas	10 months	PT Pertamina Hulu Indonesia
Acquisition of Participating Interest In Working Area Mahakam	Mahakam	East Kalimantan	01/01/2018	31/12/2037	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Acquisition of Working Area Geothermal Seulawah Agam	Seulawah Agam	Aceh	09/04/2018	08/04/2055	75%	Geothermal	37 years	PT Pertamina Geothermal Energy
Acquisition of Working Area Tuban Block	Tuban Block	East Java	20/05/2018*	19/05/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

Acquisition of working area and interest	Working area	Area	Effective date of contract	Expiry date of contract	Percentage of Participation	Production	Contract period	Owned by
Acquisition of Working Area Ogan Komering Block	Ogan Komering Block	South Sumatera	20/05/2018*	19/05/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition working interest in Sukowati Unitization Field	Sukowati	Tuban	25/06/2018	24/06/2028	100%	-	20 years	PT Pertamina EP
Acquisition of Working Area Sanga Sanga Block	Sanga Sanga Block	East Kalimantan	08/08/2018*	07/08/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Acquisition of Working Area Southeast Sumatera ("SES") Block	SES Block	South East Sumatera	06/09/2018*	05/09/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area North Sumatera Offshore ("NSO") Block	NSO Block	North Sumatera	17/10/2018*	16/10/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area East Kalimantan and Attaka Block	East Kalimantan and Attaka Block	East Kalimantan	25/10/2018*	24/10/2038	100%	Oil and gas	20 years	PT Pertamina Hulu Indonesia
Acquisition of Working Area Jambi Merang Block	Jambi Merang Block	South Sumatera	10/02/2019*	09/02/2039	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area Raja/Pendopo Block	Raja/Pendopo Block	South Sumatera	06/07/2019*	05/07/2039	100%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area Salawati Block	Salawati Block	Papua	23/04/2020*	22/04/2040	30%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area Kepala Burung Block	Kepala Burung Block	Papua	15/10/2020*	14/10/2040	30%	Oil and gas	20 years	PT Pertamina Hulu Energi
Acquisition of Working Area Maratua Block	Maratua Block	North Kalimantan & East Kalimantan	18/02/2019*	17/02/2049	100%	Oil and gas	20 years	PT Pertamina Hulu Energi

* Note 4d
** Note 4f

a. Establishment of State-owned Oil and Gas Holding Enterprise

On December 30, 2016, the Government of Indonesia ("GOI") issued Government Regulation ("PP") No. 72/2016 as a revision to PP No. 44/2005 regarding Procedures and Administration of State Capital Investment in State-Owned Enterprises and Limited Company. This regulation is the legal basis for the establishment of state-owned holding enterprise that is being deliberated by the GOI.

On February 28, 2018, the GOI issued PP No. 6/2018 regarding Additional State Capital Investment in the Company. This regulation is to increase the GOI paid-up capital in the Company by transfering 13,809,038,755 (full amount) B series of PT Perusahaan Gas Negara Tbk ("PGN")'s shares owned by the GOI, which represents 56.96% of total PGN shares, to the Company.

On March 28, 2018, the Ministry of Finance issued Decree No. 286/KMK.06/2018 regarding the determination of the value of additional state capital participation in the Company's share capital. The decree stipulates that the value of additional state capital participation in the Company's share capital is Rp38,136,346,046,696 (full amount).

On April 11, 2018, the Minister of State-Owned Enterprises ("MoSOE") issued Letter No. S-216/MBU/2018 to approve the transfer of 56.96% B series of PGN shares and additional state capital investment in the Company amounting to Rp38,136,346,046,696 (full amount). On the same date, the MoSOE issued Letter No. S-217/MBU/04/2018 to increase the Company's authorized share capital from Rp200,000,000 million to Rp600,000,000 million with nominal amount of Rp1,000,000 (full amount) per share. This letter also approved additional issued and paid-up capital of the Company by 38,136,347 shares or amounting to Rp38,136,346,046,696 (full amount) or equivalent to US$2,774,157.

Further, on April 11, 2018, the MoSOE and the Company entered into an agreement regarding the transfer of Government rights at PGN to the Company, to increase the state capital participation in the Company.

On April 13, 2018, the Minister of Law and Human Rights issued Letter No. AHU-0008395.AH.01.02. 2018 regarding Approval of Changes in PT Pertamina (Persero) Articles of Association. It is stipulated that changes to Pertamina's Article of Association has been approved which is related to the total issued and paid-up shares of Rp171,227,044,000,000 (full amount) or equivalent to US$16,191,204.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

a. Establishment of State-owned Oil and Gas Holding Enterprise (continued)

On May 9, 2018, the MoSOE, as the holder of PGN's A Series Dwiwarna share, issued a Power of attorney letter in relation to transfer of rights and authority of A series PGN share to the Company as the majority holder of B series PGN shares. This letter is to provide PT Pertamina (Persero) control over PGN.

The above transaction is recorded in accordance with SFAS 38 (Revised 2012) "Business Combination of Entities Under Common Control".

The following is a summary of PGN's financial information at the acquisition date:

	Book value
ASSETS	
Current assets	2,021,879
Non-current assets	4,442,988
Total assets	**6,464,867**
LIABILITIES	
Current liabilities	553,560
Non-current liabilities	2,649,167
Total liabilities	**3,202,727**
EQUITY	
Share capital	344,019
Other paid-in capital	284,339
Retained earnings	
Appropriated	2,427,854
Unappropriated	223,501
Other components of equity	(36,868)
Total equity attributable to owners of the parent entity	**3,242,845**
B series shares transfer representing 56.96% ownership of interest	(1,847,125)
Consideration amount	2,774,157
Additional paid-in capital	**927,032**

Based on the amendment and restatement of the share purchase agreement between the Company and PGN dated December 28, 2018, PGN officially acquired the shares of PT Pertamina Gas ("Pertagas") owned by the Company as much as 51% (or 2,591,099 shares) worth Rp20.18 trillion, equivalent to US$1,351,955. With the acquisition of these shares, PGN effectively owned 51% of Pertagas shares including Pertagas 5 subsidiaries, PT Pertagas Niaga, PT Perta Arun Gas, PT Perta Daya Gas, PT Perta-Samtan Gas, and PT Perta Kalimantan Gas. In connection with this restructuring, the Company's effective ownership of Pertagas decrease from 100% to 78.05%.

b. Control over PT Nusantara Regas

The Company and PGN own 60% and 40% ownership of interest in Regas, respectively. As a result of the establishment of state-owned oil and gas enterprise, the Company indirectly owns 82.78% ownership of interest. The management conclude that the Company has majority vote over Regas to direct relevant activities. Therefore, the Company has control over Regas and starting April 11, 2018, the Company consolidates Regas financial statements.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

b. Control over PT Nusantara Regas (continued)

The following is a summary of Regas' financial information at the date when the Company obtains control.

	Book value
ASSETS	
Current assets	233,935
Non-current assets	56,116
Total Assets	**290,051**
LIABILITIES	
Current liabilities	20,769
Non-current liabilities	12,707
Total Liabilities	**33,476**
EQUITY	
Share capital	145,589
Retained earnings	
Appropriated	43,129
Unappropriated	68,026
Other components of equity	(169)
Total Equity	**256,575**

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares

M&P is a listed company in Paris Stock Exchange which has the following production assets: Ezanga Block in Gabon (as the operator with Working Interest ("WI") of 80%); Mnazi Bay Field in Tanzania (as the operator with WI of 48.06%); and owns 20.46% shares in Seplat (a Company listed in Lagos Stock Exchange, Nigeria and London Stock Exchange, England) which has several production assets in Nigeria. M&P also has exploration assets and undeveloped discovery areas located in Italy, France, Myanmar, Canada, Tanzania, Gabon, Colombia, and Namibia.

On August 25, 2016, the Group through PT Pertamina Internasional Eksplorasi dan Produksi ("PIEP"), a wholly owned subsidiary of the Company, purchased all of the shares held by Pacifico in M&P representing 47,916,026 shares corresponding to 24.53% shares ownership in M&P. PIEP had increased its shares ownership through a tender offer process with the same terms and conditions to all M&P's shares.

The process of step-up acquisition through Voluntary Tender Offer is conducted in two stages. The first phase was completed on January 25, 2017 and the payment was made on February 1, 2017, in which PIEP owns 64.46% of M&P shares and 63.35% of voting rights, resulting in a "change of control" of M&P. The second phase of voluntary tender over was completed on February 15, 2017 and the payment was executed on February 22, 2017, therefore, from that date, PIEP becomes the holder of:

1. 141,911,939 M&P shares, representing 72.65% of share capital and 71.39% of the voting rights in M&P;
2. 14,641,233 ORNANE 2019 bonds, which represent 99.88% of the outstanding bonds;
3. 10,435,331 ORNANE 2021 bonds, which represent 99.99% of the outstanding bonds.

On December 20, 2017, M&P redeemed all ORNANE 2019 and ORNANE 2021 bonds owned by PIEP and paid in cash the nominal amount of the bonds and interest thereon, so that PIEP no longer holds ORNANE 2019 and ORNANE 2021 bonds.

Following the completion of the shares acquisition, PIEP became the majority shareholder and has full control over M&P.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares (continued)

Calculation of the fair value of identified assets and liabilities taken over by PIEP was completed on December 31, 2017.

Fair value adjustments mainly come from the valuation of reserves and sources of oil acquired, for exploration and/or production assets, in Gabon, Nigeria, Tanzania, and Venezuela.

The fair value of identified assets and liabilities arising from the acquisition of M&P are as follows:

	Amount
ASSETS	
Financial assets	353,653
Inventories	9,678
Prepaid taxes	70,844
Deferred tax assets	35,096
Long-term investments	94,697
Oil and gas properties	1,723,322
Other non-current assets	85,318
Total assets	**2,372,608**
LIABILITIES	
Financial liabilities	913,431
Tax payables	39,801
Deferred tax liabilities	371,004
Employee benefit liabilities	1,143
Provision for decommissioning and site restoration	41,110
Total liabilities	**1,366,489**
Net assets at the acquisition date (include deferred tax assets and liabilities)	**1,006,119**
Excess of book value over fair value	9,600
Fair value of net assets	1,015,719
Interest acquired	72.65%
Fair value of net assets acquired	737,920
Foreign currency translation	28,337
Bargain purchase	(54,130)
Purchase consideration through cash	**712,127**

Below is the cash flow analysis from the acquisition of M&P:

Transaction value of the acquisition	712,127
Less: Cash from M&P	(203,230)
Net cash flow to acquire control	**508,897**

The bargain purchase amount also include gain on remeasurement of the previously held equity interest amounting to US$42,658.

On November 5, 2018, M&P entered into an agreement with Rockover Energy Limited ("Rockover") to acquire the deferred payments owned by Rockover for a consideration of US$10.75 million (full amount) to be paid in cash and issuance of 5,373,209 new M&P shares.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

c. Acquisition of Etablissements Maurel et Prom SA ("M&P") shares (continued)

On December 12, 2018, the extraordinary general meeting of M&P shareholders approved the delegation of authority relating to the capital increase for the purpose of transaction with Rockover to the Board of Directors. On December 14, 2018, the Board of Directors of M&P implemented this delegation of authority and decided to carry out the capital increase for a total nominal amount of €4,137,371 (full amount) through issuance of 5,373,209 new shares with a par value of €0.77 (full amount) each and a unit subscription price of €5.182 (full amount) each. Pursuant to the completion of the capital increase, Rockover holds 2.68% of M&P's share capital and resulted to the dilution of the Company's percentage of ownership in M&P from 72.65% to 70.75%.

In October 2018, Maurel & Prom Venezuela SLU ("M&P Venezuela"), a wholly owned subsidiary of M&P, signed a Share Sale and Purchase Agreement ("SSPA") for the acquisition of Shell Exploration and Production Investments B.V. ("Shell")'s 40% interest as "Shareholder B" in Mixed Company. Mixed Company operates the Urdaneta West field in Lake Maracaibo, Venezuela. Petróleos de Venezuela S.A. ("PDVSA"), through its wholly owned subsidiaries Corporación Venezolana del Petróleo ("CVP") and PDVSA Social ("PDVSAS") - collectively referred to as "Shareholder A", own the remaining 60% stake of the Mixed Company.

On December 3, 2018, pursuant to the approval from the Ministry of Petroleum of Venezuela, M&P Venezuela effectively acquired 40% shares from Shell in Mixed Company with total consideration payment for the acquisition of €70 million, which will be settled as follows:

1. €47 million have been paid at closing of the transaction in December 2018, and
2. €23 million to be in December 2019, 1(one) year after the closing of the transaction.

d. Gross split contract ("Gross Split")

On January 13, 2017, the regulation of the Minister of Energy and Mineral Resources ("MoEMR") No. 08/2017 regarding principles of the Production Sharing Contract without Cost Recovery Mechanism, also known as Gross Split PSC, was issued.

Following the expiration of Offshore North West Java ("ONWJ") PSC on January 18, 2017, PT Pertamina Hulu Energi ONWJ ("PHE ONWJ") and Special Unit for Upstream Oil and Gas Business Activities ("SKK Migas") signed the ONWJ block Gross Split PSC which become effective from January 19, 2017 with a 20 years contract period. The Gross Split scheme between the Government of Indonesia and the Contractor is disclosed in Note 43d.

On April 20, 2018, PT Pertamina Hulu Energi Tuban East Java, PT Pertamina Hulu Energi Ogan Komering and SKK Migas signed the Gross Split Tuban Block and Ogan Komering Block PSC which were effective from May 20, 2018 with a contract period of 20 years. PT Pertamina Hulu Energi OSES, PT Pertamina Hulu Energi NSO and SKK Migas also signed the Gross Split SES Block and NSO which was effective from September 6, 2018 and October 17, 2018 with a contract period of 20 years.

On May 31, 2018, PT Pertamina Hulu Energi Raja Tempirai, PT Pertamina Hulu Energi Jambi Merang and SKK Migas signed Gross Split Raja/Pendopo Block and Jambi Merang Block PSC which become effective from July 6, 2019 and February 10, 2019, respectively, with contract period of 20 years.

On July 11, 2018, PT Pertamina Hulu Energi Hulu Salawati, PT Pertamina Hulu Energi Hulu Salawati Basin, and SKK Migas signed the Gross Split PSC for the Salawati Block and the Kepala Burung Block which became effective from April 23, 2020 and October 15, 2020, respectively.

On April 20, 2018, PT Pertamina Hulu Sanga sanga and SKK Migas signed the Gross Split contract for the Sanga sanga block which became effective from August 8, 2018 for 20 years.

On April 20, 2018, Pertamina Hulu Kalimantan Timur and SKK Migas signed a Gross Split contract for the East Kalimantan and Attaka Block which became effective from October 25, 2018 for 20 years.

On February 18, 2019, PT Pertamina Hulu Energi Lepas Pantai Bunyu signed the Gross Split Maratua Block PSC with a 30-years contract period, which is effective from the date the signing of the PSC.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

e. Mahakam production sharing contract

In accordance with MoEMR Letter No. 2793/13/ME.M/2015 regarding *Pengelolaan Wilayah Kerja ("WK") Mahakam Pasca 2017*, the Company is appointed as the operator of the Mahakam Contract Area from the previous contractors Total E&P Indonesie and INPEX Corporation. To manage such working area, the Company, through PT Pertamina Hulu Indonesia ("PHI"), established a new entity called PT Pertamina Hulu Mahakam ("PHM").

Mahakam PSC was signed on December 29, 2015 by SKK Migas and PHM with effective date on January 1, 2018. The PSC uses the concept of production sharing, but has introduced a new sliding scale approach to calculate the contractor entitlement based on Revenue Over Costs ("R/C") ratio.

On October 25, 2016, the Amendment of Mahakam PSC was adopted, adding some important points, including the certainty of the costs incurred by PHM after the date of signing the contract but before the effective date of the contract. These costs will be included in cost recovery as operating cost after the effective date of contract.

On April 20, 2018, the second amendment of Mahakam PSC was signed, adding some important points, including the addition of Tengah working area into Mahakam working area. This amendment was effective on October 5, 2018.

The PSC term refers to PP. No. 79 Year 2010, where the assume and discharge mechanism for taxes that became incentives for PSC Contractors are treated as part of the cost to be recovered through the cost recovery mechanism.

The provisions are as follows:

- **Crude oil and natural gas production sharing**

  The sharing of oil production between PHM and the Government is 23.5294% and 76.4706%, respectively, while sharing of gas production is 47.0588% and 52.9412% for the first year of contract. The R/C factor in effect in the first year is 1.3 as stipulated in the PSC. Oil and gas production sharing for subsequent years are listed in the table below with R/C factor at the end of previous year.

  The R/C factor itself is the contractor's cumulative revenue from the date of signing the contract divided by the contractor's cumulative cost since the signing of the contract.

R/C	Tax Rate	Gross Contractor Share		Net Contractor Share	
		Oil	Gas	Oil	Gas
0 – 1	36.25%	31.3726%	54.9020%	20%	35%
0 – 1.2	36.25%	27.4510%	50.9804%	18%	33%
1.2 – 1.4	36.25%	23.5294%	47.0588%	15%	30%
1.4 – 1.6	36.25%	19.6078%	43.1373%	12%	28%
> 1.6	36.25%	15.6863%	39.2157%	10%	25%

- **First Tranche Petroleum ("FTP")**

  The Government and PHM are entitled to receive an amount equal to 20% of the total production of oil and gas each year before any deduction for recovery of operating costs and investment credit. FTP is shared between the Government and PHM in accordance with the entitlements to oil and gas production.

  As at the authorization date of these consolidated financial statements, the scheme for utilization of assets previously utilized by the predecessor Mahakam PSC contractors has not yet been determined by the Government, in this case the Directorate General of State Assets and MoEMR.

  On April 20, 2018, the second amendment of Mahakam PSC was signed, adding some important points, including the addition of Tengah working area into Mahakam working area. This amendment became effective on October 5, 2018.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

f. Addition of 41.37% of PT Pertamina EP Cepu's ("PEPC") participating interest in Jambaran-Tiung Biru ("JTB") unitization field

Effective November 3, 2017, PEPC acquired an additional 41.37% participating interest in the JTB unitization field previously held by ExxonMobil Cepu Limited and Ampolex (Cepu) Pte. Ltd., increasing the Company's participating interest in JTB unitization field to 82.74%. The other contractors in JTB field are PT Pertamina EP with 8.06% and Badan Usaha Milik Daerah ("BUMD") with 9.19%.

Through Letter No. 001/KETUA-BKS/XI/2017 dated November 17, 2017 and Letter No. 004/KETUA-BKS/XII/2017 dated December 19, 2017, Cooperating Body Participating Interest Block ("PI BKS") Cepu conveyed the resignation of 4 Members of the PI BKS Cepu Block namely PT Asri Dharma Sejahtera ("ADS"), PT Sarana Patra Hulu Cepu ("SPHC"), PT Blora Patragas Hulu ("BPH"), PT Petrogas Jatim Utama Cendana ("PJUC"), which the four members stated they would not participate in the development of the Jambaran-Tiung Biru Field Gas project ("JTB") starting January 1, 2018.

Effective January 1, 2018, the Company added a 9.19% participating interest in the JTB unitization field previously owned by the PI BKS (ADS, SPHC, BPH, PJUC) so that the Company's participating interest in the JTB unitization field becomes 91.93%. Payment for this acquisitions totaled to US$16,764. The acquisitions of this participating interests was recorded as an additional oil and gas assets.

g. Establishment of PT Pertamina Hulu Rokan ("PHR")

Based on the Decree of the Minister of Energy and Mineral Resources No. 1923K/10/MEM/2018 dated August 6, 2018 regarding Agreement on Management of Establishment of Principal Forms and Conditions (Terms and Conditions) of Cooperation Contracts in Rokan Work Areas, one of the requirements that must be fulfilled by Pertamina includes preparing a new subsidiary, signature bonus and payment of work commitments.

On December 20, 2018, PT Pertamina Hulu Rokan was established based on Notarial Deed No.13 dated December 20, 2018 from Lenny Janis Ishak, S.H. Deed of establishment of PHR was approved by the Minister of Law and Human Rights through Letter No. AHU-0061348.AH.01.01.2018 dated December 21, 2018. PHR will manage the Rokan Block from 2021 to 2041. Total authorized capital of PHR is US$3,140,000 with paid-in capital of US$785,000. The paid-up capital was used to pay the signing bonus to the Government of Indonesia in the amount of US$783,980 on December 21, 2018, and is to be used as working capital during the first year of managing its working area.

h. Addition of 20% of PT Pertamina EP's participating interest in Sukowati unitization field

Based on SKK Migas letter No. SRT-0493/SKKMA0000/2018/S1 dated June 25, 2018 regarding the determination of the new unitization operator of Sukowati Field, CPA Mudi production facilities and Cintanatomas FSO, PT Pertamina EP was appointed as the new operator of the Sukowati Field.

Based on a joint agreement regarding the management of Sukowati Field unitization, the operation of the CPA Mudi production facility and Cintanatomas FSO dated May 16, 2018 between PT Pertamina EP and PT Pertamina Hulu Energi Tuban East Java, it was agreed that PT Pertamina EP had an interest participation unit of 100% (Note 43c).

i. Temporary cooperation contract of Attaka working area

The Temporary Cooperation Contract ("TCC") was made and signed on November 2, 2017 by SKK Migas and PT Pertamina Hulu Attaka, explained all terms, conditions, rights and obligations, of and pursuant to the ex-Attaka PSC shall be applicable to the TCC from the date of January 1, 2018 until October 24, 2018.

j. Decrease in the percentage of ownership of the Company at PT Asuransi Tugu Pratama Indonesia Tbk (formerly PT Tugu Pratama Indonesia)

On May 28, 2018, ATPI became a public company by issuing 177,777,800 shares of new shares. As a result, the percentage of the Company's ownership in ATPI decreased from 65.0% to 58.5%. This reduction in the percentage of ownership does not result in a loss of Company's control in ATPI. Thus, the impact of this transaction amounting to US$20,551 is calculated as an equity transaction and recorded in the difference account of transactions with non-controlling interests.

4. ACQUISITION AND ADDITION OF PARTICIPATING INTEREST (continued)

k. Addendum to the agreement on the transfer and management of the ONWJ Block PSC

On February 6, 2019, PHE ONWJ and PT Migas Hulu Jabar ONWJ ("MUJ ONWJ") have signed an addendum on the transfer agreement and management of 10% working interest at ONWJ PSC. MUJ's share of production from the ONWJ PSC, less its share of expenses in the PSC from January 19, 2017 to December 31, 2018 is US$16,303. Settlement of such amount has been made by PHE ONWJ to MUJ on February 8, 2019.

Starting from the date of the transfer, payments of MUJ ONWJ's share of the production is made on a monthly basis by PHE ONWJ after deducting MUJ ONWJ's share of the ONWJ PSC's operating costs and other obligations in accordance with the PSC.

In the event MUJ ONWJ's share of production in the current month is insufficient to cover for MUJ ONWJ's share of operating costs, the cumulative underpayment will be carried over to the following months.

To ensure MUJ ONWJ's revenue, the production sharing and operating costs sharing with MUJ ONWJ is calculated based on provisional percentage for a full year, in accordance with the attachment to the addendum to the agreement. In the event in any year the cumulative operating costs which is payable by MUJ ONWJ to PHE ONWJ exceeds MUJ ONWJ's share of production, PHE ONWJ will pay US$1 (full amount) for each month in the following year.

5. PURPOSE OF PREPARATION AND ISSUANCE OF CONSOLIDATED FINANCIAL STATEMENTS

These consolidated financial statements has been prepared solely for inclusion in the offering document in connection with the proposed offering of the debt securities of the Company in the United States of America and outside of the United States of America in reliance on Rule 144A and Regulation S, respectively, under the United States Securities Act of 1993.

6. CASH AND CASH EQUIVALENTS

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Cash on hand	11,425	4,119	8,174	5,976
Cash in banks	3,698,377	5,045,496	2,770,229	3,011,880
Time deposits	4,612,308	4,062,697	3,631,424	3,703,712
Total	**8,322,110**	**9,112,312**	**6,409,827**	**6,721,568**

The details of cash and cash equivalents based on currency and by individual bank are as follows:

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Cash on hand:				
Rupiah	10,480	3,128	7,515	5,205
US Dollar	826	891	567	654
Others	119	100	92	117
Total cash on hand	**11,425**	**4,119**	**8,174**	**5,976**

6. CASH AND CASH EQUIVALENTS (continued)

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Cash in banks				
US Dollar:				
Government-related entities				
- PT Bank Rakyat Indonesia (Persero) Tbk ("BRI")	795,012	891,329	514,299	770,965
- PT Bank Negara Indonesia (Persero) Tbk ("BNI")	720,685	844,933	636,281	627,690
- PT Bank Mandiri (Persero) Tbk ("Bank Mandiri")	478,385	581,752	562,533	722,517
- Other banks (each below US$10,000)	1,982	1,526	852	9,033
Third parties				
- Crédit Agricole Corporate and Investment Bank ("Crédit Agricole CIB", previously "Calyon")	264,703	214,982	83,209	-
- PT Bank Sumitomo Mitsui Indonesia ("SMBC Indonesia")	82,455	2,515	32,293	42,645
- Citibank, N.A. ("Citibank")	44,850	49,440	35,603	31,751
- J.P. Morgan Chase & Co.	22,677	16,130	-	-
- PT Bank Maybank Indonesia Tbk ("Maybank" previously PT Bank Internasional Indonesia "BII")	4,230	3,797	4,523	10,367
- Sumitomo Mitsui Banking Corporation	-	94,194	-	-
- Other banks (each below US$10,000)	9,556	9,735	14,291	26,128
Total US Dollar accounts	2,424,535	2,710,333	1,883,884	2,241,096
Rupiah:				
Government-related entities				
– Bank Mandiri	364,354	651,073	270,785	277,654
– BNI	332,423	547,355	185,568	93,136
– PT Bank Tabungan Negara (Persero) Tbk ("BTN")	224,180	265,065	198,404	177,970
– BRI	186,733	598,851	132,696	138,245
– PT Bank BRIsyariah Tbk ("BRI Syariah")	21,306	48,692	9	6
– PT Bank BNI Syariah ("BNI Syariah")	1,852	14,188	1,065	705
– Others banks (each below US$10,000)	4,944	9,745	2,664	4,106
Third parties				
– PT Bank Central Asia Tbk ("BCA")	54,824	40,008	32,022	31,243
– Citibank	12,148	24,875	20,965	5,210
– Other banks (each below US$10,000)	16,274	17,866	15,622	16,048
Total Rupiah accounts	1,219,038	2,217,718	859,800	744,323
Euro:				
Government-related entities				
– BNI	7	8	554	4
– BRI	1	1	1	18,271
– Bank Mandiri	-	220	123	8
Third parties				
– Crédit Agricole CIB	11,787	64,889	-	-
Total Euro accounts	11,795	65,118	678	18,283
Malaysian Ringgit:				
Third parties				
– RHB Bank Berhad	33,600	39,417	20,946	868
Cash in banks-other currency accounts-Third Parties	9,409	12,910	4,921	7,310
Total cash in banks	**3,698,377**	**5,045,496**	**2,770,229**	**3,011,880**

6. CASH AND CASH EQUIVALENTS (continued)

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Time deposits with original maturities of three months or less				
US Dollar accounts:				
Government-related entities				
– BRI	1,346,308	508,397	1,003,976	221,095
– BNI	865,279	193,671	398,530	168,163
– Bank Mandiri	553,210	32,760	22,958	417,300
– PT Bank Syariah Mandiri ("Bank Syariah Mandiri")	5	50,005	5	5
– BTN	-	127,500	17,500	-
Third parties				
– MUFG Bank, Ltd. ("MUFG Bank" previously The Bank of Tokyo Mitsubishi UFJ)	35,770	-	-	-
– Citibank	20,000	15,000	-	-
– PT Bank Bukopin Tbk ("Bukopin")	7,400	7,900	3,670	10,227
– PT Bank Muamalat Tbk ("Bank Muamalat")	4,000	12,000	-	21,550
– Industrial and Commercial Bank of China Ltd. ("ICBC")	-	20,000	-	-
– BCA	-	-	-	10,000
– Other banks (each below US$10,000)	11,211	-	245	12,893
Total time deposits - US Dollar accounts	2,843,183	967,233	1,446,884	861,233
Rupiah accounts:				
Government-related entities				
– BRI	730,629	1,351,105	999,443	1,303,358
– BTN	361,113	454,425	129,046	56,168
– Bank Mandiri	201,776	516,931	410,020	659,767
– BNI	177,734	505,346	471,616	698,688
– PT Bank BNI Syariah ("BNI Syariah")	89,160	18,591	29,340	38,070
– Bank Syariah Mandiri	88,086	137,711	48,435	38,642
– PT Bank Rakyat Indonesia Agroniaga Tbk ("BRI Agroniaga)	48,602	47,807	25,834	21,584
– BRI Syariah	14,041	13,811	148	149
– Other banks (each below US$10,000)	1,404	3,453	2,804	2,345
Third parties				
– ICBC	21,129	-	-	-
– PT Bank Bukopin Tbk	13,531	12,098	24,648	2,108
– Bank Muamalat	7,858	7,032	4,601	10,159
– BCA	1.404	3,798	23,620	1,489
– Other banks (each below US$10,000)	12,476	17,015	14,985	9,952
Total time deposits-Rupiah accounts	1,768,943	3,089,123	2,184,540	2,842,479
Time deposits-other currencies accounts	182	6,341	-	-
Total time deposits	**4,612,308**	**4,062,697**	**3,631,424**	**3,703,712**
Total cash and cash equivalents	**8,322,110**	**9,112,312**	**6,409,827**	**6,721,568**

Annual interest rates on time deposits during three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016, were as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Rupiah	3.45%-8.50%	3.25%-9.00%	3.00%-8.75%	3.75%-10.50%
US dollar	0.24%-3.27%	0.50%-3.37%	0.40%-2.36%	0.50%-1.75%
Singapore dollar	0.50%	0.50%	-	-

The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of cash and cash equivalents mentioned above.

7. RESTRICTED CASH

Restricted cash are moneys in escrow accounts in US dollar and Indonesian rupiah, and are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
US dollar accounts:				
Government-related entities				
– Bank Mandiri	56,088	58,140	2,165	3,819
– BNI	12,035	10,401	38,526	29,965
– BRI	11,731	11,725	40,469	69,784
Third parties				
– BNP Paribas	18,000	18,000	18,000	-
– SMBC Indonesia	4,552	4,000	11,752	-
– Other banks (each below US$10,000)	685	685	231	413
Rupiah accounts:				
Government-related entities				
– BNI	4,333	3,553	3,453	4,243
– BRI	969	1,421	3,408	6,066
– Bank Mandiri	944	990	875	978
Third parties				
– Other banks (each below US$10,000)	-	-	792	7,429
	109,337	**108,915**	**119,671**	**122,697**

Annual interest rates on restricted cash during during three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016 were as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Rupiah	3.50%-8.44%	5.00%-7.80%	2.00%-8.50%	0.75%-5.60%
US dollar	0.04%-2.70%	0.24%-0.88%	0.75%-0.80%	0.10%-0.80%

US dollar accounts

The escrow accounts were related to letters of credit (“L/C”) issued for the procurement of crude oil and other petroleum products as well as bank guarantees.

Rupiah accounts

The escrow accounts are time deposits used as collateral for bank guarantees and performance bonds.

8. RECEIVABLES - THIRD PARTIES

a. Trade receivables

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Trade receivables	2,399,099	2,161,456	1,792,133	1,646,792
Provision for impairment	(212,126)	(228,001)	(211,506)	(204,340)
Total	**2,186,973**	**1,933,455**	**1,580,627**	**1,442,452**

8. RECEIVABLES - THIRD PARTIES (continued)

a. Trade receivables (continued)

Movements in the provision for impairment of trade receivables are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(228,001)	(211,506)	(204,340)	(189,221)
Impairment during the period/year	(664)	(29,957)	(42,001)	(16,762)
Reversal of impairment on the recovered receivables during the period/year	44	7,652	33,935	2,987
Foreign exchange difference	16,495	5,810	900	(1,344)
Ending balance	**(212,126)**	**(228,001)**	**(211,506)**	**(204,340)**

The maximum exposure to credit risk at reporting date is the carrying value of the receivables mentioned above. The Group does not hold any collateral as security.

Based on management's review of the collectability of each balance of trade receivables as at the dates of March 31, 2019, and December 31, 2018, 2017, and 2016, management believes that the provision for impairment is adequate to cover the potential losse as a result of uncollected third party trade receivables.

Certain trade receivables were pledged as collateral for certain subsidiaries' long term loans (Note 20a).

Management believes that there are no significant concentrations on credit risk involving trade receivables from third parties.

Details of trade receivables by curencies are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
US dollar	1,478,628	1,323,528	1,037,216	1,097,431
Rupiah	919,670	837,130	754,907	549,361
Singapore dollar	705	700	-	-
Euro	96	98	10	-
Total	**2,399,099**	**2,161,456**	**1,792,133**	**1,646,792**

b. Other receivables

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Reinsurance assets	336,692	333,119	243,068	245,188
Receivables from subsidiary operations in oil and gas related activities	171,270	132,545	256,883	134,990
Others	290,261	286,788	139,060	281,255
Sub-total	798,223	752,452	639,011	661,433
Provision for impairment	(18,180)	(18,140)	(18,551)	(11,635)
Total other receivables	**780,043**	**734,312**	**620,460**	**649,798**

8. RECEIVABLES - THIRD PARTIES (continued)

b. Other receivables (continued)

Reinsurance assets represent the amount of premium paid or part of PT Asuransi Tugu Pratama Indonesia Tbk premium for prospective reinsurance and retrocession transactions.

Movements in the provision for impairment of other receivables are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	(18,140)	(18,551)	(11,635)	(9,010)
Recovery/(additions) of impairment during the period/year	(40)	411	(6,916)	(2,625)
Ending balance	**(18,180)**	**(18,140)**	**(18,551)**	**(11,635)**

Based on a review of the balance of other receivables at the end of the year, management believes that the allowance for impairment losses is adequate to cover possible losses that may arise from uncollectible other receivables.

9. DUE FROM THE GOVERNMENT

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
The Company:				
Receivables on revenue recognition from Disparity of Selling Price	3,029,233	2,924,148	-	-
Receivables from reimbursement of subsidy costs for LPG 3 kg cylinders	1,471,665	1,147,538	1,404,911	1,068,920
Receivables from reimbursement of subsidy costs for certain fuel (BBM) products	368,762	175,556	473,928	422,398
Receivables for kerosene subsidies reimbursement	17,108	16,828	-	-
Receivables from marketing fees	77,179	72,489	49,902	86,811
Kerosene conversion	10,767	10,626	-	-
Others	-	-	102	14
Sub-total	4,974,714	4,347,185	1,928,843	1,578,143
Subsidiaries	592,192	411,224	337,832	214,314
	5,566,906	4,758,409	2,266,675	1,792,457
Provision for impairment	-	-	(110,936)	-
Total (Note 41)	**5,566,906**	**4,758,409**	**2,155,739**	**1,792,457**
Current portion	(2,537,673)	(1,834,261)	(1,492,625)	(1,792,457)
Non-current portion	**3,029,233**	**2,924,148**	**663,114**	**-**

Movements in the provision for impairment of due from the Government are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	-	(110,936)	-	(33,196)
Impairment during the period/year	-	-	(363,830)	-
Reversal of impairment during the period/year	-	106,085	252,894	7,312
Adjustment	-	-	-	25,884
Foreign exchange gain	-	4,851	-	-
Ending balance	**-**	**-**	**(110,936)**	**-**

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price

Details of receivable from revenue recognition from Disparity of Selling Price are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Receivables on revenue recognition from Disparity of Selling Price:				
2018	2,657,132	2,657,132	-	-
2017	1,248,347	1,248,347	-	-
Sub total	**3,905,479**	**3,905,479**	**-**	**-**
Initial fair value adjustments of receivables:				
2018	(773,562)	(773,562)	-	-
2017	(207,769)	(207,769)	-	-
Sub total	**(981,331)**	**(981,331)**	**-**	**-**
Net receivables amount post fair value adjustment before unwinding interest, changes in estimate and effect of foreign exchange difference:				
2018	1,883,570	1,883,570	-	-
2017	1,040,578	1,040,578	-	-
Sub total	**2,924,148**	**2,924,148**	**-**	**-**
Effects of unwinding interest:				
2018	37,293	-	-	-
2017	19,568	-	-	-
Sub total	**56,861**	**-**	**-**	**-**
Effect of foreign exchange difference in 2019:				
2018	31,058	-	-	-
2017	17,166	-	-	-
Sub total	**48,224**	**-**	**-**	**-**
Net ending balance:				
2018	1,951,921	1,883,570	-	-
2017	1,077,312	1,040,578	-	-
TOTAL	**3,029,233**	**2,924,148**	**-**	**-**

On July 16, 2018, BPK issued its audit results ("LHP") No. 36/AUDITAMA VII/PDTT/07/2018 on the calculation and distribution of subsidized JBT Diesel Fuel and 3 kg LPG cylinders. Based on such LHP, the Company is recommended to request reimbursement from the Government for the 2017 Disparity of Selling Price of JBT Diesel Fuel amounting to Rp20.79 trillion or equivalent to US$1,444,076 (including Value Added Tax - "VAT" and Motor Vehicle Fuel Tax - "PBBKB" amounting to Rp2.71 trillion or equivalent to US$188,358) and JBKP Premium amounting to Rp5.51.trillion or equivalent to $382,904 (including VAT and PBBKB amounting to Rp0.72 trillion or equivalent to US$49,944).

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price (continued)

In accordance with the MoF Letter No. 642/MK.02/2018 dated August 24, 2018, the MoF, after coordinating with the MoEMR and the MoSOE, issued a policy that the Government would reimburse the Company's revenue shortfall from the sale of JBT Diesel Fuel in accordance with BPK's LHP.

On May 20, 2019, the BPK issued its LHP with Specific Purposes on the Sales and Distribution of Fuel Oil and 3kg LPG Cylinders, and Calculation of JBT Diesel Fuel & 3kg LPG Cylinders Subsidized in 2018 to PT Pertamina (Persero), PT AKR Corporindo Tbk., and other related agencies in North Sumatera, Riau, South Sumatera, Lampung, Banten, DKI Jakarta, West Java, Central Java, Yogyakarta Special Region, East Java, West Nusa Tenggara, West Kalimantan, East Kalimantan, North Sulawesi, South Sulawesi, North Maluku, and Papua No. 31/AUDITAMA VII/PDTT/05/2019, which was received by the Company on May 23, 2019. Based on such LHP, among others, the Company experienced:

- Shortfall of revenue from Disparity of Selling Price in the distribution of JBT Diesel Fuel in 2018 amounting to Rp29.31 trillion or equivalent to $2,024,203 (including VAT and PBBKB amounting to Rp18 trillion or equivalent to US$288,943);
- Shortfall of revenue from Disparity of Selling Price in the distribution of JBT Kerosene in 2018 amounting to Rp243.68 billion or equivalent to US$16,828 (excluding VAT) due to the determination of Market Index Prices ("HIP") and Basic Prices of Kerosene JBT not in accordance with the calculation of formula retail retail prices of fuel oil;
- Shortfall of revenue from Disparity of Selling Price in the distribution of JBKP Premium in 2018 amounting to Rp23.27 trillion or equivalent to $1,456,076 (including VAT and PBBKB), which consists of shortfall of revenue in the distribution of JBKP Premium in Java, Madura, and Bali ("Jamali") and outside Java, Madura, and Bali ("Non Jamali") areas amounting to Rp7.74 trillion or equivalent to US$534,205 (including VAT and PBBKB) and Rp15.53 trillion or equivalent to US$921,871 (including VAT and PBBKB), respectively;
- Excess of revenue from the sale of JBKP Premium Jamali that exceeded the Government stipulated HJE amounting to Rp234.82 billion or equivalent to US$16,216 due to the determination of the Jamali area to be the assignment area;

Based on such LHP, the Company was recommended by BPK to coordinate with the MoF, the MoEMR and the MoSOE in respect to the policy of regulating shortfall of revenue in the distribution of JBT Diesel Fuel, JBT Kerosene and JBKP Premium in 2018, in accordance with applicable procedures and regulations. Meanwhile, for the Company's excess of revenue from sale of the JBKP Premium Jamali, the Company was recommended by the BPK to deposit such excess of revenue with the State Treasury.

In accordance with the MoF Letter No. S-430/MK.02/2019 dated May 28, 2019, the MoF, after coordinating with the MoEMR and the MoSOE, issued a policy that the Government will reimburse the Company's revenue shortfall from the sale of JBT Diesel Fuel and JBKP Premium Non-Jamali in accordance with BPK's LHP No. 31/AUDITAMA VII/PDTT/05/2019. Meanwhile, the excess and shortfall of the Company's revenue from the sale of JBKP Premium Jamali become the excess and shortfall of Company's revenue.

Prior to receiving BPK's LHP and the MoF letter discussed above, the Company received BPK Letter No. 126/S/XX/05/2019 on Submission of Draft Audit Reports with Specific Purposes on the Sales and Distribution of Fuel Oil and 3kg LPG Cylinders, and Calculation of JBT Diesel Oil & 3kg LPG Cylinders Subsidized in 2018 to PT Pertamina (Persero), PT AKR Corporindo Tbk., and other related agencies dated May 17, 2019 and MoSOE Letter No. SR-330/MBU/05/2019 dated May 17, 2019 regarding the bookkeeping of the disparity in retail selling price of JBT and JBKP Non Jamali and the shortfall in of revenue from JBT Kerosene with the value in accordance with the draft of the BPK audit report.

Based on the above matters, the Company recognized revenue and due from Government for the 2018 Disparity of Selling Price of JBT Diesel Fuel and JBKP Premium Non-Jamali, prior to fair value adjustment, amounting to Rp25.13 trillion or equivalent to US$1,735,260 (excluding VAT and PBBKB amounting to Rp4.18 trillion or equivalent to US$288,943) and Rp13.35 trillion or equivalent to US$921,871 (excluding VAT and PBBKB amounting to Rp2.19 trillion or equivalent to US$151,057), respectively and the 2017 Disparity of Selling Price of JBT Diesel Fuel, prior to fair value adjustment, amounting to Rp18.08 trillion or equivalent to US$1,248,347 (excluding VAT and PBBKB of Rp2.71 trillion or equivalent to US$187,252).

9. DUE FROM THE GOVERNMENT (continued)

a. Receivables on revenue recognition from Disparity of Selling Price (continued)

The assumptions used for calculating the fair value of receivable on revenue recognation from Disparity of Selling Price are as follows:

Year	Payment Installments	Discount interest rate (yield) Government Rupiah Bonds	Estimate Year of Receipt
2018	Installment 1	7.91%	2022
	Installment 2	8.01%	2023
2017	Installment 1	7.38%	2020
	Installment 2	7.72%	2021

b. Receivable from reimbursement of subsidy costs for LPG 3kg cylinders

These receivables represent subsidy reimbursements for 3kg LPG cylinders which were distributed to the public by the Company. This Government assignment is in the form of a PSO and its pricing is based on a yearly contract with MoEMR.

The receivable balance for the 3kg LPG cylinders subsidy will be settled through the APBN mechanism in the next period.

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	1,147,538	1,404,911	1,068,920	934,825
Subsidy reimbursements for 3kg LPG cylinders for current year (Note 29)	675,269	3,496,603	2,977,967	1,817,647
Correction from government audit for subsidy reimbursement for 3kg LPG cylinders for the year:				
- 2018 (Note 29)	-	(1,252)	-	-
- 2017 (Note 29)	-	(5,661)	-	-
- 2016 (Note 29)	-	-	(484)	-
- 2015 (Note 29)	-	-	-	(479)
Cash received	(441,132)	(3,614,277)	(2,624,110)	(1,720,295)
Foreign exchange gain (loss)	89,990	(132,786)	(17,382)	37,222
Ending balance	**1,471,665**	**1,147,538**	**1,404,911**	**1,068,920**

9. DUE FROM THE GOVERNMENT (continued)

c. Receivables from reimbursement of subsidy costs for certain fuel (BBM) products

The Company's receivable of subsidy reimbursements for BBM products represents billings for the BBM subsidy provided to the public.

The PSO mandate to the Company from the Government is based on annual contract with BPH Migas. The retail sales price of the subsidised BBM products is based on MoEMR's Decree.

The receivable balance of subsidy reimbursements for BBM products will be setlled through the next State Budget and Expenditure ("APBN") period.

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	175,556	473,928	422,398	893,062
Subsidy reimbursements for BBM products for current year (Note 29)	520,120	2,126,796	595,206	753,250
Taxes	30,922	266,693	69,617	83,145
Correction from Government audit for subsidy reimbursement for BBM products for the year:				
- 2018 (Note 29)	-	(699)	-	-
- 2017 (Note 29)	-	(147)	-	-
- 2016 (Note 29)	-	-	(605)	-
- 2015 (Note 29)		-	-	(1,574)
Cash received	(364,055)	(2,600,487)	(600,992)	(1,334,981)
Gain/(loss) on foreign exchange	6,219	(90,528)	(11,696)	29,496
Ending balance	**368,762**	**175,556**	**473,928**	**422,398**

Corrections of the calculation of the fuel subsidy cost reimbursement bill is based on the results of the BPK's and recorded in the period in which the audit was completed.

On August 16, 2018, the MoEMR issued Regulation No. 40 of 2018 which replaces MoEMR Regulation No. 39 of 2014 regarding the calculation of the retail selling price of fuel oil. In accordance with the new regulation, the retail selling price of Automotive Diesel Oil ("ADO") per liter at the point of delivery is calculated based on formula prices, including VAT, with a maximum subsidy of Rp2,000 (full amount) per liter and applied retrospectively starting January 1, 2018

d. Receivables for kerosene subsidies reimbursement

As discussed in Note 9a above, based on BPK's LHP No. 31/AUDITAMA VII/PDTT/05/2019 dated May 20, 2019, the Company experienced a shortfall of revenue in the distribution of JBT Kerosene in 2018 amounting to Rp243.68 billion (excluding VAT amounting to Rp24.38 billion) due to the determination of Market Index Prices ("HIP") and Basic Prices of Kerosene JBT were not in accordance with the calculation of formula retail prices of fuel oil stipulated in MoEMR Decree No.62K/10/MEM/2019 regarding Basic Formula Price for Specific Type of Fuel Oils and Special Types of Fuel Assignment. The Company's management believes that such shortfall of revenue will be reimbursed by the Government through a subsidy mechanism.

9. DUE FROM THE GOVERNMENT (continued)

e. Receivables from marketing fees

These receivables represent amounts due from the Government through SKK Migas to the Company for fees from marketing activities in relation to the Government's crude oil, natural gas and LNG.

The details of marketing fees are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Receivables of marketing fees:				
2019	4,690	-	-	-
2018	22,587	22,587	-	-
2017	26,529	26,529	26,529	-
2016	23,373	23,373	23,373	23,373
2015	-		-	20,698
2014	-		-	9,150
2013	-		-	9,007
2012	-		-	11,866
2011	-		-	12,717
Total	**77,179**	**72,489**	**49,902**	**86,811**

f. Subsidiaries receivables

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
PEP				
- Domestic Market Obligation ("DMO") fees	106,928	106,398	90,930	77,340
- Underlifting	-	18,942	-	-
PHE				
- DMO fees	18,357	15,414	25,859	25,613
- Underlifting	21,860	25,730	46,480	31,395
PEPC				
- Underlifiting	423,189	224,904	174,563	79,966
PHI				
- DMO fees	21,858	18,780	-	-
- Underlifting	-	1,056	-	-
Total – subsidiaries	**592,192**	**411,224**	**337,832**	**214,314**

DMO fees represent amounts due from the Government in relation with the obligations of subsidiaries in providing crude oil to meet domestic market needs for oil products in accordance with their KKS.

The underlifting receivables represent receivables from subsidiaries of SKK Migas as a result of SKK Migas, actual lifting of crude oil and gas being higher than its entitlement for the respective year.

Based on management's review of the collectibility of each balance of subsidiaries receivables, management believes that the provision for impairment is adequate to cover potential losses as a result of uncollected subsidiaries' receivables from Government.

10. INVENTORIES

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Gas	19,713	13,984	23,528	6,711
Crude oil:				
Domestic production	1,156,513	1,026,225	1,029,639	799,513
Imported	516,536	579,765	754,663	467,391
Sub-total for crude oil	1,673,049	1,605,990	1,784,302	1,266,904
Oil products:				
Automotive Diesel Oil (“ADO”)	1,104,680	1,018,791	755,620	593,658
Premium gasoline	573,184	536,309	594,740	461,811
Pertamax, Pertamax Plus, Pertalite gasoline and Pertadex (diesel oil)	503,894	491,005	451,999	311,575
Oil products in process of production	374,611	399,963	347,408	327,709
Intermediary	341,751	337,246	272,786	254,826
Avtur and Avigas	306,297	264,545	220,903	125,795
LPG	186,599	262,104	277,690	207,856
Industrial/Marine Fuel Oil (“IFO/MFO”)	160,332	148,621	118,515	97,658
Petrochemicals	157,463	170,815	127,457	116,969
Kerosene	91,176	94,299	75,503	73,808
Industrial Diesel Oil (“IDO”)	15,900	17,563	21,722	27,315
Others	406,711	476,999	514,176	391,537
Sub-total for oil products	4,222,598	4,218,260	3,778,519	2,990,517
Sub-total for gas, crude oil and oil Products	5,915,360	5,838,234	5,586,349	4,264,132
Less:				
Provision for decline in value of oil products (Note 32)	(106,421)	(167,270)	(92,854)	(76,542)
	5,808,939	5,670,964	5,493,495	4,187,590
Materials	827,357	754,228	645,825	637,655
Less:				
Provision for decline in value of materials	(106,049)	(102,027)	(103,183)	(30,223)
	721,308	652,201	542,642	607,432
Total	**6,530,247**	**6,323,165**	**6,036,137**	**4,795,022**

Movements in the provision for decline in value of oil products are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(167,270)	(92,854)	(76,542)	(225,457)
Reversal/(addition) during the period/year - net (Note 32)	60,849	(74,416)	(16,312)	148,915
Ending balance	**(106,421)**	**(167,270)**	**(92,854)**	**(76,542)**

Movements in the provision for decline in value of materials are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(102,027)	(103,183)	(30,223)	(29,459)
(Addition)/reversal during the period/year - net	(4,022)	1,156	(72,960)	(764)
Ending balance	(106,049)	(102,027)	(103,183)	(30,223)

10. INVENTORIES (continued)

Management believes that the provision for decline in value of oil products and materials are adequate to cover possible losses that may arise from a decline in the realizable value of inventories.

As of March 31, 2019, inventories were insured against fire and other risks (Note 13). Management believes that the insurance coverage amount is adequate to cover any possible losses that may arise in relation to the insured inventories.

11. OTHER INVESTMENTS

These investments represent net assets held for distribution to the Company in connection to the liquidation of Pertamina Energy Trading Limited ("Petral"), Zambesi Investment Limited ("Zambesi") and Pertamina Energy Services Pte.Ltd. ("PES") in accordance with the General Meeting of Shareholder ("GMS") decision of the Company on July 13, 2015.

On March 13, 2017, Petral has distributed its funds to the Company.

On June 16, 2017, Zambesi was liquidated.

On October 31, 2017, Petral was liquidated.

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the balance of net assets held for distribution to the Company based on the liquidator's report for PES amounted to US$85,089, US$80,171, US$27,328, and US$43,190, respectively.

Based on the Company's GMS dated January 3, 2019, the Company's shareholder agreed to extend the liquidation period of PES until the completion of the dissolution/liquidation process, and approve the Company to take the corporate actions needed to complete the dissolution/liquidation.

12. LONG-TERM INVESTMENTS

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Investment in oil and gas blocks - net	925,804	1,024,237	1,227,187	1,427,011
Investments in associates - net	726,277	725,846	583,694	697,850
Investment in bonds - net	391,307	391,307	391,307	391,307
Investments in joint ventures	361,082	369,922	457,405	480,756
Investment properties	288,173	280,668	284,354	304,373
Investments in shares of stock - net	6,292	6,292	6,292	6,292
Other financial assets	29,685	20,782	20,679	21,850
Total	**2,728,620**	**2,819,054**	**2,970,918**	**3,329,439**

a. Investment in oil and gas block

Investment in oil and gas blocks represents the Group's investment in several oil and gas blocks located in Malaysia which is being operated by Murphy Sabah Oil Co. Ltd. and Murphy Sarawak Oil Co. Ltd. The Group recorded the investment using the equity method because it has significant influence in the undivided interest of those oil and gas blocks.

The movement of investments in oil and gas block are as follows:

	March 31, 2019 (unaudited)					
	Beginning balance	Addition	Adjustment	Transfer	Recovery/ (impairment) in value	Ending balance
Cost	1,556,487	-	3,457	-	(76,354)	1,483,590
Accumulated amortization	(532,250)	(25,536)	-	-	-	(557,786)
Net book value	**1,024,237**	**(25,536)**	**3,457**	**-**	**(76,354)**	**925,804**

12. LONG-TERM INVESTMENTS (continued)

a. Investment in oil and gas block (continued)

The movement of investments in oil and gas block are as follows (continued):

	December 31, 2018					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,614,965	-	96,295	-	(154,773)	1,556,487
Accumulated amortization	(387,778)	(144,472)	-	-	-	(532,250)
Net book value	**1,227,187**	**(144,472)**	**96,295**	**-**	**(154,773)**	**1,024,237**

	December 31, 2017					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,698,348	-	(113)	-	(83,270)	1,614,965
Accumulated amortization	(271,337)	(116,441)	-	-	-	(387,778)
Net book value	**1,427,011**	**(116,441)**	**(113)**	**-**	**(83,270)**	**1,227,187**

	December 31, 2016					
	Beginning balance	Addition	Adjustment	Transfer	Recovery (impairment) in value	Ending balance
Cost	1,632,706	12,269	(60,917)	-	114,290	1,698,348
Accumulated amortization	(156,861)	(114,476)	-	-	-	(271,337)
Net book value	**1,475,845**	**(102,207)**	**(60,917)**	**-**	**114,290**	**1,427,011**

b. Investments in associates

The movement of investments in associates are as follows:

	March 31, 2019 (unaudited)							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- Pacific Petroleum & Trading Co. Ltd.	50.00%	48,038	-	-	598	-	-	48,636
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	82,005	-	1,980	(14,027)	-	-	69,958
		130,043	-	1,980	(13,429)	-	-	118,594
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	279,219	-	-	4,693	-	-	283,912
- PT Asuransi Samsung Tugu	19.50%	9,069	-	-	142	-	(15)	9,196
- Seplat Petroleum Development Company Plc, Nigeria	21.37%	224,548	-	-	7,227	-	-	231,775
Others	19.70%-50%	82,967	-	-	(167)	-	-	82,800
		595,803	-	-	11,895	-	(15)	607,683
Total investments in associates		**725,846**	**-**	**1,980**	**(1,534)**	**-**	**(15)**	**726,277**

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

The movement of investments in associates are as follows (continued):

	December 31, 2018							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- Pacific Petroleum & Trading Co. Ltd.	50.00%	35,489	-	-	12,549	-	-	48,038
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	151,937	-	-	(69,932)	-	-	82,005
		187,426	-	-	(57,383)	-	-	130,043
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	240,437	-	2	38,780	-	-	279,219
- PT Asuransi Samsung Tugu	19.50%	8,741	-	19	434	(125)	-	9,069
- Seplat Petroleum Development Company Plc, Nigeria	20.46%	92,440	-	68,043	76,124	(12,059)	-	224,548
- PT Gas Energi Jambi [c)]	40.00%	-	-	-	-	-	-	-
- Others	19.67%-50.00%	54,650	27,458	2,298	(1,439)	-	-	82,967
		396,268	27,458	70,362	113,899	(12,184)	-	595,803
Total investments in associates		**583,694**	**27,458**	**70,362**	**56,516**	**(12,184)**	**-**	**725,846**

	December 31, 2017							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- Pacific Petroleum & Trading Co. Ltd.	50.00%	32,499	-	1,516	2,616	(1,142)	-	35,489
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	204,907	-	-	(52,970)	-	-	151,937
		237,406	-	1,516	(50,354)	(1,142)	-	187,426
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	195,083	-	-	45,354	-	-	240,437
- PT Tugu Reasuransi Indonesia [a)]	33.01%	29,849	-	(29,849)	-	-	-	-
- PT Asuransi Samsung Tugu	19.50%	8,290	-	(19)	648	(178)	-	8,741
- Etablissements Maurel et Prom SA [b)] (Notes 4c)	72.65%	227,222	-	(227,222)	-	-	-	-
- Seplat Petroleum Development Company Plc, Nigeria	21.37%	-	92,440	-	-	-	-	92,440
- PT Gas Energi Jambi [c)]	40.00%	-	-	-	-	-	-	-
- Others	19.67%-50.00%	-	54,650	-	-	-	-	54,650
		460,444	147,090	(257,090)	46,002	(178)	-	396,268
Total investments in associates		**697,850**	**147,090**	**(255,574)**	**(4,352)**	**(1,320)**	**-**	**583,694**

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

The movement of investments in associates are as follows (continued):

	December 31, 2016							
	Percentage of ownership	Beginning balance	Additions (deduction)	Other changes	Share in net income/ (loss)	Dividends	Recovery (impairment) in value	Ending balance
The Company								
- Pacific Petroleum & Trading Co. Ltd.	50.00%	29,179	-	2,720	1,966	(1,366)	-	32,499
- Korea Indonesia Petroleum Co. Ltd. Labuan [d]	45.00%	1,178	(434)	(642)	(102)	-	-	-
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	48.59%	259,416	-	-	(54,509)	-	-	204,907
		289,773	(434)	2,078	(52,645)	(1,366)	-	237,406
Indirect investments in shares of associates								
- PT Donggi Senoro LNG	29.00%	176,831	-	-	18,252	-	-	195,083
- PT Tugu Reasuransi Indonesia	24.47%	24,411	-	2,167	5,444	(2,173)	-	29,849
- PT Asuransi Samsung Tugu	19.50%	7,697	-	(85)	893	(215)	-	8,290
- Etablissements Maurel et Prom SA [b] (Notes 4c)	24.53%	-	227,222	-	-	-	-	227,222
- PT Gas Energi Jambi [c]	40.00%	-	-	-	-	-	-	-
		208,939	227,222	2,082	24,589	(2,388)	-	460,444
Total investments in associates		**498,712**	**226,788**	**4,160**	**(28,056)**	**(3,754)**	**-**	**697,850**

[a] In 2017, the Group has control over PT Tugu Reasuransi Indonesia ("TRI") and consolidates its financial statements.
[b] On February 15, 2017, PT Pertamina Internasional Eksplorasi & Produksi had a 72.65% ownership interest in Etablissements Maurel et Prom SA and consolidates its financial instrument.
[c] PGN has ownership interest in PT Gas Energi Jambi ("GEJ") by 40,00% from 2015, GEJ suffered loss.
[d] In 2016, the Company sold its shares in Korea Indonesia Petroleum Co. Ltd., Labuan.

Management believes that the provision for decline in value of investments in associates is adequate to cover possible losses that may arise from declining in value.

12. LONG-TERM INVESTMENTS (continued)

b. Investments in associates (continued)

The Group's share of the results of its principal associates and their aggregated assets (including goodwill) and liabilities, are as follows:

	Country of Incorporation	Assets	Liabilities	Revenues	Profit (loss)	Percentage of ownership
March 31, 2019 (unaudited)						
- Pacific Petroleum & Trading Co. Ltd.	Japan	101,182	(19,951)	108,454	1,080	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	852,429	(708,450)	18,242	(28,870)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,685,285	(1,692,324)	336,205	16,182	29.00%
- PT Asuransi Samsung Tugu	Indonesia	60,962	(30,309)	1,367	472	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,578,113	(948,507)	143,651	32,676	20.46%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%
December 31, 2018						
- Pacific Petroleum & Trading Co. Ltd.	Japan	118,983	(30,486)	731,189	25,098	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	866,155	(697,385)	65,136	(141,991)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,646,556	(1,669,778)	1,174,024	133,726	29.00%
- PT Asuransi Samsung Tugu	Indonesia	61,997	(31,766)	9,046	1,446	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,526,565	(925,680)	746,140	146,576	20.46%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%
December 31, 2017						
- Pacific Petroleum & Trading Co. Ltd.	Japan	153,471	(82,496)	692,966	5,232	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	601,445	(1,045,454)	59,574	(50,519)	48.59%
- PT Donggi Senoro LNG	Indonesia	2,466,693	(1,627,338)	998,208	155,704	29.00%
- PT Asuransi Samsung Tugu	Indonesia	55,775	(36,791)	11,161	2,163	19.50%
- Seplat Petroleum Development Company Plc, Nigeria	Nigeria	2,207,964	(975,232)	371,413	(3,307)	21.37%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%
December 31, 2016						
- Pacific Petroleum & Trading Co. Ltd.	Japan	135,085	(70,089)	524,180	3,932	50.00%
- PT Trans-Pacific Petrochemical Indotama ("TPPI")	Indonesia	604,629	(996,212)	42,935	(53,421)	48.59%
- Korea Indonesia Petroleum Co. Ltd., Labuan	Malaysia	2,447	(62)	-	(228)	45.00%
- PT Donggi Senoro LNG	Indonesia	2,454,345	(1,774,286)	755,295	73,038	29.00%
- PT Tugu Reasuransi Indonesia	Indonesia	202,633	(124,060)	107,491	14,456	24.47%
- PT Asuransi Samsung Tugu	Indonesia	62,071	(34,436)	10,798	2,977	19.50%
- Etablissements Maurel et Prom SA [a] (Notes 4c)	France	2,443,992	(1,348,198)	149,588	(38,565)	24.53%
- PT Gas Energi Jambi	Indonesia	41	(653)	-	-	40.00%

c. Investment in bonds

As of March 31, 2019 and December 31, 2018, 2017, and 2016, investment in bonds represents investment in bonds issued by PT Trans-Pacific Petrochemical Indotama.

12. LONG-TERM INVESTMENTS (continued)

d. Investment in joint ventures

The movements of investments in joint ventures are as follows:

	March 31, 2019 (unaudited)							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	89,976	(23,100)	-	5,062	-	-	71,938
- PT Patra SK	35.00%	62,406	-	(30)	1,365	-	-	63,741
- PT Indo Thai Trading	51.00%	7,070	-	(22)	478	-	-	7,526
- PT Perta Daya Gas	65.00%	3,734	-	-	845	-	-	4,579
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	407	-	-	-	-	-	407
- PT Elnusa CGGVeritas Seismic	20.96%	-	-	-	-	-	-	-
- PT Transportasi Gas Indonesia	59.87%	202,743	-	(998)	7,265	-	-	209,010
- PT Permata Karya Jasa	60.00%	3.586	-	-	295	-	-	3,881
Total investments in joint venture		**369,922**	**(23,100)**	**(1,050)**	**15,310**	**-**	**-**	**361,082**

	December 31, 2018							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	91,173	-	32	21,871	(23,100)	-	89,976
- PT Patra SK	35.00%	65,769	-	-	5,387	(8,750)	-	62,406
- PT Indo Thai Trading	51.00%	6,281	790	(791)	790	-	-	7,070
- PT Perta Daya Gas	65.00%	1,683	-	28	2,023	-	-	3,734
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	407	-	-	-	-	-	407
- PT Elnusa CGGVeritas Seismic	20.96%	-	-	-	-	-	-	-
- PT Transportasi Gas Indonesia	59.87%	281,700	-	(1,013)	27,814	(105,758)	-	202,743
- Unimar L.L.C *)	50.00%	10,392	(7,176)	(1,657)	6,941	(8,500)	-	-
- PT Permata Karya Jasa	60.00%	-	2,416	-	1,382	(212)	-	3,586
Total investments in joint ventures		**457,405**	**(3,970)**	**(3,401)**	**66,208**	**(146,320)**	**-**	**369,922**

*) Unimar L.L.C 11,25% participating interest in old Sanga-sanga PSC which expired on August 8, 2018.

	December 31, 2017							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Perta Samtan Gas	66.00%	79,383	-	7,355	17,635	(13,200)	-	91,173
- PT Patra SK	35.00%	68,919	-	(26)	3,876	(7,000)	-	65,769
- PT Indo Thai Trading	51.00%	4,815	-	(2)	1,468	-	-	6,281
- PT Perta Daya Gas	65.00%	1,403	-	(111)	391	-	-	1,683
- PT Pertamina Rosneft Pengolahan dan Petrokimia	55.00%	-	407	-	-	-	-	407
- PT Elnusa CGGVeritas Seismic	20.96%	-	-	-	-	-	-	-
- PT Transportasi Gas Indonesia	59.87%	281,167	-	-	26,072	(25,539)	-	281,700
- Unimar L.L.C	50.00%	45,069	-	-	(7,177)	(27,500)	-	10,392
Total investments in joint ventures		**480,756**	**407**	**7,216**	**42,265**	**(73,239)**	**-**	**457,405**

12. LONG-TERM INVESTMENTS (continued)

d. Investment in joint ventures (continued)

The movements of investments in joint ventures are as follows (continued):

	December 31, 2016							
	Percentage of ownership	Beginning balance	Additional investment	Other changes	Share in net income (loss)	Dividends	Recovery (impairment) in value	Ending balance
Indirect investments in joint ventures								
- PT Patra SK	35.00%	64,538	-	(13)	4,394	-	-	68,919
- PT Indo Thai Trading	51.00%	3,711	-	-	1,104	-	-	4,815
- PT Perta Samtan Gas	66.00%	77,368	-	-	5,513	(3,498)	-	79,383
- PT Perta Daya Gas	65.00%	1,301	-	-	102	-	-	1,403
- PT Elnusa CGGVeritas Seismic	20.96%	-	-	-		-	-	-
- PT Transportasi Gas Indonesia	59.87%	278,516	-		26,357	(23,706)	-	281,167
- Unimar L.L.C	50.00%	-	53,724	11,074	(1,729)	(18,000)	-	45,069
Total investments in joint ventures		**425,434**	**53,724**	**11,061**	**35,741**	**(45,204)**	**-**	**480,756**

The Group's share of the results of its principal joint ventures and their aggregated assets (including goodwill) and liabilities are as follows:

	Country of Incorporation	Assets	Liabilities	Revenues	Profit (loss)	Percentage ownership
March 31, 2019 (unaudited)						
- PT Patra SK	Indonesia	248,043	(65,927)	74,981	3,899	35.00%
- PT Perta Samtan Gas	Indonesia	164,605	(47,771)	54,990	7,671	66.00%
- PT Perta Daya Gas	Indonesia	47,101	(39,367)	6,165	1,300	65.00%
- PT Indo Thai Trading	Indonesia	28,738	(13,981)	33,580	895	51.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	513	-	-	20	20.96%
- PT Transportasi Gas Indonesia	Indonesia	442,302	(91,198)	37,904	12,136	59.87%
- PT Permata Karya Jasa*	Indonesia	5,423	(1,155)	2,448	436	60.00%
December 31, 2018						
- PT Patra SK	Indonesia	232,842	(54,539)	341,114	15,391	35.00%
- PT Perta Samtan Gas	Indonesia	166,010	(29,683)	121,802	33,187	66.00%
- PT Perta Daya Gas	Indonesia	48,618	(42,873)	12,497	3,113	65.00%
- PT Indo Thai Trading	Indonesia	35,332	(21,470)	184,779	1,549	51.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	511	-	-	3	20.96%
- PT Transportasi Gas Indonesia	Indonesia	735,029	(96,391)	153,413	46,458	59.87%
- Unimar L.L.C	USA	33,740	(19,387)	43,918	13,881	28.48%
- PT Permata Karya Jasa*	Indonesia	6,308	(2,040)	16,301	1,383	60.00%
December 31, 2017						
- PT Patra SK	Indonesia	244,717	(59,696)	259,596	11,072	35.00%
- PT Perta Samtan Gas	Indonesia	180,172	(42,032)	106,950	26,720	66.00%
- PT Perta Daya Gas	Indonesia	53,219	(50,630)	12,469	602	65.00%
- PT Indo Thai Trading	Indonesia	31,994	(19,369)	156,716	2,869	51.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	515	-	-	-	20.96%
- PT Transportasi Gas Indonesia	Indonesia	557,875	(87,357)	151,625	43,548	59.87%
- Unimar L.L.C	USA	49,370	(31,899)	61,993	(9,991)	50.00%
- PT Pertamina Rosneft Pengolahan dan Petrokimia	Indonesia	739	-	-	-	55.00%
December 31, 2016						
- PT Patra SK	Indonesia	239,169	(42,256)	213,705	12,553	35.00%
- PT Indo Thai Trading	Indonesia	18,885	(9,445)	116,865	2,164	51.00%
- PT Perta Samtan Gas	Indonesia	179,326	(47,852)	73,617	8,353	66.00%
- PT Perta Daya Gas	Indonesia	59,460	(57,473)	12,842	157	65.00%
- PT Elnusa CGGVeritas Seismic	Indonesia	522	-	-	-	20.96%
- PT Transportasi Gas Indonesia	Indonesia	618,630	(149,001)	158,719	44,024	59.87%
- Unimar L.L.C	USA	109,733	(27,270)	14,435	(3,458)	50.00%

* Note 1b.iii

12. LONG-TERM INVESTMENTS (continued)

e. Investment properties

	March 31, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	266,911	-	-	8,360	275,271
Buildings	42,102	-	-	(186)	41,916
Total historical cost	309,013	-	-	8,174	317,187
Accumulated depreciation:					
Buildings	(28,345)	(465)	-	(204)	(29,014)
Net book value	**280,668**				**288,173**

	December 31, 2018				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	269,226	1,074	(17,368)	13,979	266,911
Buildings	43,287	1,217	-	(2,402)	42,102
Total historical cost	312,513	2,291	(17,368)	11,577	309,013
Accumulated depreciation:					
Buildings	(28,159)	(2,058)	-	1,872	(28,345)
Net book value	**284,354**				**280,668**

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	288,314	-	-	(19,088)	269,226
Buildings	43,042	-	-	245	43,287
Total historical cost	331,356	-	-	(18,843)	312,513
Accumulated depreciation:					
Buildings	(26,983)	(2,301)	-	1,125	(28,159)
Net book value	**304,373**				**284,354**

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassi-fications	Ending balance
Historical cost:					
Land and land rights	265,358	1,018	-	21,938	288,314
Buildings	29,095	-	-	13,947	43,042
Total historical cost	294,453	1,018	-	35,885	331,356
Accumulated depreciation:					
Buildings	(19,301)	(973)	-	(6,709)	(26,983)
Net book value	**275,152**				**304,373**

Depreciation expenses for the three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016 with respect to such investment properties amounted to US$465, US$2,058, US$2,301 and US$973, respectively (Note 37).

12. LONG-TERM INVESTMENTS (continued)

e. Investment properties (continued)

As of March 31, 2019, all of the Group's investment properties, except land and land rights, were insured against fire and other possible risks (Note 13).

As of March 31, 2019, and December 31, 2018, 2017, and 2016, management has estimated fair values of the investment properties to be US$1,384,415, US$1,803,218, US$1,503,088, and US$2,068,793, respectively.

Rental income from investment properties recognized for the three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016 amounted to US$19,991, US$26,588, US$11,792, and US$29,836 respectively.

Based on the Group management's review, there were no events or changes in circumstances which indicated impairment in the value of investment properties as of March 31, 2019, and December 31, 2018, 2017, and 2016.

f. Investments in shares of stock

	Percentage of ownership				Balance			
	March 31, 2019 (unaudited)	December 31,			March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016		2018	2017	2016
The Company								
- PT Seamless Pipe Indonesia Jaya	4.97%	4.97%	10.40%	10.40%	25,026	25,026	25,026	25,026
- PT Arun NGL [a)]	100.00%	100.00%	100.00%	85.00%	170	170	170	170
- PT Badak NGL [b)]	55.00%	55.00%	55.00%	55.00%	149	149	149	149
					25,345	25,345	25,345	25,345
Subsidiaries								
- PT Staco Jasapratama Indonesia	4.46%	4.46%	4.46%	4.46%	751	751	751	751
- PT Marga Raya Jawa Tol	6.86%	6.86%	6.86%	6.86%	2,690	2,690	2,690	2,690
- PT Trans Javagas Pipeline	10.00%	10.00%	10.00%	10.00%	739	739	739	739
- PT Asuransi Maipark Indonesia	7.31%	7.31%	7.31%	7.31%	604	604	604	604
- PT Bhakti Patra Nusantara	4.11%	4.11%	4.11%	4.11%	77	77	77	77
- PT Banten Gas Sinergy	0.14%	0.14%	0.14%	0.14%	3	3	3	3
					4,864	4,864	4,864	4,864
Total					**30,209**	**30,209**	**30,209**	**30,209**
Provision for impairment					(23,917)	(23,917)	(23,917)	(23,917)
Net					**6,292**	**6,292**	**6,292**	**6,292**

[a)] in liquidation process
[b)] refer to note 2d

The Group classified its investments in shares of stock as available-for-sale at cost because the Company, in subtance, does not control those companies. These investments are measured at cost since their fair values cannot be measured reliably.

The Group did not recognize its share on the changes in the joint ventures entities' net assets arising from other comprehensive income since the amounts are not material.

g. Other financial assets

As of March 31, 2019, and December 31, 2018, 2017, and 2016, other financial assets mainly represent investment in bonds owned by PT Asuransi Tugu Pratama Indonesia (formerly PT Tugu Pratama Indonesia).

13. FIXED ASSETS

	March 31, 2019 (unaudited)					
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Translations	Ending balance
Acquisition cost						
Direct acquisition:						
Land and land rights	1,705,095	656	-	2	1,915	1,707,668
Tanks, pipeline installations and other equipment	9,322,018	1,267	-	(66,451)	574	9,257,408
Refineries	4,265,934	-	-	12	17	4,265,963
Buildings	1,281,451	318	-	(25,533)	2,196	1,258,432
Ships and aircrafts	2,096,335	306	-	14,066	3,853	2,114,560
Moveable assets	1,633,638	2,131	-	50,613	6,209	1,692,591
Assets under construction	2,129,917	169,637	(1,470)	(9,989)	1,848	2,289,943
Sub-total	22,434,388	174,315	(1,470)	(37,280)	16,612	22,586,565
Finance lease assets:						
Land rights	-	-	-	-	-	-
Buildings	205,737	-	-	-	-	205,737
Tanks, pipelines installations and other equipment	414,634	-	-	(34,785)	-	379,849
Moveable assets	167,015	-	-	102	403	167,520
Sub-total	787,386	-	-	(34,683)	403	753,106
Total acquisition cost	**23,221,774**	**174,315**	**(1,470)**	**(71,963)**	**17,015**	**23,339,671**
Accumulated depreciation						
Direct acquisition:						
Land rights	(212)	-	-	-	(25)	(237)
Tanks, pipeline installation and other equipment	(4,834,321)	(93,693)	-	(94,934)	(320)	(5,023,268)
Refineries	(2,598,926)	(63,244)	-	-	481	(2,661,689)
Buildings	(526,815)	(15,296)	-	(14,860)	(775)	(557,746)
Ships and aircrafts	(813,091)	(28,577)	-	-	(840)	(842,508)
Moveable assets	(986,804)	(29,174)	-	21,372	(3,295)	(997,901)
Sub-total	(9,760,169)	(229,984)	-	(88,422)	(4,774)	(10,083,349)
Finance lease assets:						
Land rights	-	-	-	-	-	-
Buildings	(161,389)	(4,937)	-	-	-	(166,326)
Tanks, pipeline installations and other equipment	(249,815)	(8,890)	-	2,324	-	(256,381)
Moveable assets	(136,838)	(1,446)	-	(28)	(226)	(138,538)
Sub-total	(548,042)	(15,273)	-	2,296	(226)	(561,245)
Total accumulated depreciation	**(10,308,211)**	**(245,257)**	**-**	**(86,126)**	**(5,000)**	**(10,644,594)**
Provision for Impairment	(54,289)	-	-	-	(11)	(54,300)
Net book value	**12,859,274**					**12,640,777**

13. FIXED ASSETS (continued)

	December 31, 2018					
	Beginning balance	Additions	Deduction	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost						
Direct acquisition:						
Land and land rights	1,702,277	3,034	-	5,618	(5,834)	1,705,095
Tanks, pipeline installations and other equipment	9,168,847	28,693	(569)	131,485	(6,438)	9,322,018
Refineries	4,022,746	145,518	-	97,740	(70)	4,265,934
Buildings	1,200,885	20,252	(367)	70,994	(10,313)	1,281,451
Ships and aircrafts	2,015,720	120,523	-	(26,626)	(13,282)	2,096,335
Moveable assets	1,624,785	36,722	(5,875)	7,713	(29,707)	1,633,638
Assets under construction	1,446,340	1,083,618	-	(397,603)	(2,438)	2,129,917
Sub-total	21,181,600	1,438,360	(6,811)	(110,679)	(68,082)	22,434,388
Finance lease assets:						
Land rights	157,605	-	-	(155,364)	(2,241)	-
Buildings	83,987	-	-	121,750	-	205,737
Tanks, pipeline installations and other equipment	369,534	44,097	-	1,003	-	414,634
Moveable assets	156,432	10,707	-	-	(124)	167,015
Sub-total	767,558	54,804	-	(32,611)	(2,365)	787,386
Total acquisition cost	**21,949,158**	**1,493,164**	**(6,811)**	**(143,290)**	**(70,447)**	**23,221,774**
Accumulated depreciation						
Direct acquisition:						
Land rights	(876)	-	-	-	664	(212)
Tanks, pipeline installations and other equipment	(4,393,822)	(504,253)	42	58,559	5,153	(4,834,321)
Refineries	(2,349,134)	(249,586)	-	(307)	101	(2,598,926)
Buildings	(477,017)	(52,430)	271	(1,435)	3,796	(526,815)
Ships and aircrafts	(775,835)	(105,264)	-	65,138	2,870	(813,091)
Moveable assets	(969,682)	(103,113)	5,697	61,156	19,138	(986,804)
Sub-total	(8,966,366)	(1,014,646)	6,010	183,111	31,722	(9,760,169)
Finance lease assets:						
Land rights	(82,872)	(6,070)	-	88,942	-	-
Buildings	(58,902)	(14,272)	-	(88,215)	-	(161,389)
Tanks, pipeline installations and other equipment	(210,786)	(38,302)	-	(727)	-	(249,815)
Moveable assets	(133,666)	(7,877)	-	4,628	77	(136,838)
Sub-total	(486,226)	(66,521)	-	4,628	77	(548,042)
Total accumulated depreciation	**(9,452,592)**	**(1,081,167)**	**6,010**	**187,739**	**31,799**	**(10,308,211)**
Provision for impairment	(57,055)	-	2,719	-	47	(54,289)
Net book value	**12,439,511**					**12,859,274**

13. FIXED ASSETS (continued)

	December 31, 2017					
	Beginning balance	Additions	Deduction	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost						
Direct acquisition:						
Land and land rights	1,663,116	29,716	-	10,259	(814)	1,702,277
Tanks, pipeline installations and other equipment	8,226,598	156,997	(1,855)	787,473	(366)	9,168,847
Refineries	3,815,932	175,395	(349)	31,774	(6)	4,022,746
Buildings	1,003,055	16,298	(1,984)	193,110	(9,594)	1,200,885
Ships and aircrafts	1,894,266	52,838	-	70,460	(1,844)	2,015,720
Moveable assets	1,563,969	86,287	(7,203)	(29,853)	11,585	1,624,785
Assets under construction	1,792,241	999,558	(12,896)	(1,332,310)	(253)	1,446,340
Sub-total	19,959,177	1,517,089	(24,287)	(269,087)	(1,292)	21,181,600
Finance lease assets:						
Land rights	122,815	-	-	35,216	(426)	157,605
Buildings	83,987	-	-	-	-	83,987
Tanks, pipeline installations and other equipment	305,567	63,967	-	-	-	369,534
Moveable assets	152,167	6,498	-	(1,740)	(493)	156,432
Sub-total	664,536	70,465	-	33,476	(919)	767,558
Total acquisition cost	**20,623,713**	**1,587,554**	**(24,287)**	**(235,611)**	**(2,211)**	**21,949,158**
Accumulated depreciation						
Direct acquisition:						
Land rights	(697)	-	-	(181)	2	(876)
Tanks, pipeline installations and other equipment	(3,883,879)	(544,907)	676	34,121	167	(4,393,822)
Refineries	(2,139,241)	(223,626)	-	13,722	11	(2,349,134)
Buildings	(426,461)	(59,431)	492	8,136	247	(477,017)
Ships and aircrafts	(675,211)	(101,882)	-	849	409	(775,835)
Moveable assets	(883,826)	(106,150)	4,229	21,281	(5,216)	(969,682)
Sub-total	(8,009,315)	(1,035,996)	5,397	77,928	(4,380)	(8,966,366)
Finance lease assets:						
Land rights	(70,578)	(12,294)	-	-	-	(82,872)
Buildings	(50,506)	(8,396)	-	-	-	(58,902)
Tanks, pipeline installations and other equipment	(165,624)	(34,098)	-	(11,064)	-	(210,786)
Moveable assets	(121,208)	(9,216)	-	(4,432)	1,190	(133,666)
Sub-total	(407,916)	(64,004)	-	(15,496)	1,190	(486,226)
Total accumulated depreciation	**(8,417,231)**	**(1,100,000)**	**5,397**	**62,432**	**(3,190)**	**(9,452,592)**
Provision for impairment	(49,697)	(7,364)	-	-	6	(57,055)
Net book value	**12,156,785**					**12,439,511**

13. FIXED ASSETS (continued)

	December 31, 2016					
	Beginning balance	Additions	Deductions	Transfer/ Reclassification	Translation	Ending balance
Acquisition cost						
Direct acquisition:						
Land and land rights	1,113,305	3,237	(939)	544,045	3,468	1,663,116
Tanks, pipeline installations and other equipment	7,015,411	12,777	(11,277)	1,208,973	714	8,226,598
Refineries	4,487,794	-	-	(671,900)	38	3,815,932
Buildings	841,550	18,364	(20,161)	156,743	6,559	1,003,055
Ships and aircrafts	1,800,419	41,322	-	49,316	3,209	1,894,266
Moveable assets	1,381,379	101,011	(15,858)	97,441	(4)	1,563,969
Assets under construction	1,939,028	986,629	(33,639)	(1,099,905)	128	1,792,241
Sub-total	18,578,886	1,163,340	(81,874)	284,713	14,112	19,959,177
Finance lease assets:						
Land rights	122,815	-	-	-	-	122,815
Buildings	83,987	-	-	-	-	83,987
Tanks, pipeline installations and other equipment	272,691	32,876	-	-	-	305,567
Moveable assets	190,330	4,514	(202)	(42,254)	(221)	152,167
Sub-total	669,823	37,390	(202)	(42,254)	(221)	664,536
Total acquisition cost	**19,248,709**	**1,200,730**	**(82,076)**	**242,459**	**13,891**	**20,623,713**
Accumulated depreciation						
Direct acquisition:						
Land rights	(504)	(188)	-	-	(5)	(697)
Tanks, pipeline installations and other equipment	(3,025,001)	(391,058)	548	(467,954)	(414)	(3,883,879)
Refineries	(1,937,916)	(225,810)	-	24,511	(26)	(2,139,241)
Buildings	(388,353)	(43,391)	10,546	(5,536)	273	(426,461)
Ships and aircrafts	(675,123)	(96,221)	-	96,723	(590)	(675,211)
Moveable assets	(770,756)	(170,185)	11,433	51,518	(5,836)	(883,826)
Sub-total	(6,797,653)	(926,853)	22,527	(300,738)	(6,598)	(8,009,315)
Finance lease assets:						
Land rights	(58,182)	(12,396)	-	-	-	(70,578)
Buildings	(42,088)	(8,418)	-	-	-	(50,506)
Tanks, pipeline installations and other equipment	(138,503)	(27,121)	-	-	-	(165,624)
Moveable assets	(107,256)	(25,064)	-	6,915	4,197	(121,208)
Sub-total	(346,029)	(72,999)	-	6,915	4,197	(407,916)
Total accumulated depreciation	**(7,143,682)**	**(999,852)**	**22,527**	**(293,823)**	**(2,401)**	**(8,417,231)**
Provision for impairment	(44,354)	(7,151)	-	1,808	-	(49,697)
Net book value	**12,060,673**					**12,156,785**

13. FIXED ASSETS (continued)

The allocation of depreciation expenses are as follows:

	For the three-month period ended March 31, 2019 (unaudited)	For the years ended December 31,		
		2018	2017	2016
Cost of goods sold (Note 32)	125,827	566,412	551,911	501,823
Expenses from other operating activities (Note 35)	23,523	88,405	84,636	77,454
Selling and marketing expenses (Note 36)	78,998	328,695	362,241	313,688
General and administrative expenses (Note 37)	16,909	97,655	101,212	106,887
Total	**245,257**	**1,081,167**	**1,100,000**	**999,852**

As of March 31, 2019, the Group owned parcels of land at various locations in Indonesia with Building Rights Title ("HGB") ranging from 20-30 years. Some of the HGBs are near their expiration dates. Management believes that those HGB licenses can be extended upon their expirations.

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the Group's inventories, investment properties, fixed assets, and oil & gas and geothermal properties, except for land and land rights (Notes 10,12, 13, and 14), were insured against fire and other possible risks for a total insurance coverage of US$53,642,273, and US$53,391,900, US$50,430,767 and US$46,056,456 respectively.

Management believes that the insurance coverage is adequate to cover any possible losses that may arise in relation to the insured assets.

Certain fixed assets were pledged as collateral for certain subsidiary long term loans (Note 20a).

Interest capitalized as part of fixed assets for the three-month periods ended March 31, 2019, and the years ended December 31, 2018, 2017, and 2016 amounted to US$1,704, and US$31,500, US$25,611, and US$16,689 respectively.

Management believes that the provision for impairment in the value of fixed assets as of March 31, 2019, and December 31, 2018, 2017, and 2016 is adequate to cover any possible losses from impairment of fixed assets.

Assets under construction as of March 31, 2019, and December 31, 2018, 2017, and 2016 consists of refineries, buildings, vessels, installations and moveable assets.

14. OIL AND GAS AND GEOTHERMAL PROPERTIES

	March 31, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost					
Direct acquisition:					
Land and land rights	18,281	-	-	-	18,281
Oil and gas wells	15,461,845	20,583	-	110,590	15,593,018
Geothermal wells	759,351	-	-	-	759,351
Installations	7,675,508	17,827	(169)	19,231	7,712,397
LPG plants	1,538,366	-	-	-	1,538,366
Buildings	198,613	-	-	1,208	199,821
Moveable assets	418,511	-	-	5,494	424,005
Sub-total	26,070,475	38,410	(169)	136,523	26,245,239
Assets under construction					
Exploratory and evaluation wells	1,380,730	172,816	-	22,368	1,575,914
Development wells	2,423,499	283,310	-	(205,921)	2,500,888
Sub-total	3,804,229	456,126	-	(183,553)	4,076,802
Finance lease assets:					
Installations	4,672	-	-	-	4,672
LPG plants	12,501	-	-	-	12,501
Buildings	19,939	-	-	-	19,939
Moveable assets	195,595	-	-	-	195,595
Sub-total	232,707	-	-	-	232,707
Total acquisition cost	**30,107,411**	**494,536**	**(169)**	**(47,030)**	**30,554,748**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	March 31, 2019 (unaudited)				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization					
Direct acquisition:					
Oil and gas wells	(7,076,161)	(318,914)	-	14,802	(7,380,273)
Geothermal wells	(152,127)	(9,857)	-	-	(161,984)
Installations	(2,717,802)	(126,087)	-	-	(2,843,889)
LPG plants	(293,601)	(20,024)	-	-	(313,625)
Buildings	(48,441)	(3,087)	-	-	(51,528)
Moveable assets	(244,360)	(8,179)	-	-	(252,539)
Sub-total	(10,532,492)	(486,148)	-	14,802	(11,003,838)
Finance lease assets:					
Installations	(18,723)	(522)	-	-	(19,245)
LPG plants	(5,777)	-	-	-	(5,777)
Buildings	(18,522)	(61)	-	-	(18,583)
Moveable assets	(181,398)	(5)	-	-	(181,403)
Sub-total	(224,420)	(588)	-	-	(225,008)
Total accumulated depreciation, depletion and amortization	**(10,756,912)**	**(486,736)**	**-**	**14,802**	**(11,228,846)**
Provision for impairment	(736,213)	(46,504)	-	(1,338)	(784,055)
Net book values	**18,614,286**				**18,541,847**

	December 31, 2018				
	Beginning Balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost					
Direct acquisition:					
Land and land rights	18,243	-	-	38	18,281
Oil and gas wells	13,915,574	1,116,330	(107,073)	537,014	15,461,845
Geothermal wells	671,595	4,671	-	83,085	759,351
Installations	7,213,878	109,761	(1,195)	353,064	7,675,508
LPG plants	1,538,366	-	-	-	1,538,366
Buildings	173,184	1,152	-	24,277	198,613
Moveable assets	346,955	39,034	-	32,522	418,511
Sub-total	23,877,795	1,270,948	(108,268)	1,030,000	26,070,475
Assets under construction					
Exploratory and evaluation wells	1,326,425	606,380	(120,381)	(431,694)	1,380,730
Development wells	2,096,876	1,163,019	(4,519)	(831,877)	2,423,499
Sub-total	3,423,301	1,769,399	(124,900)	(1,263,571)	3,804,229
Finance lease assets:					
Installations	4,672	-	-	-	4,672
LPG plants	12,501	-	-	-	12,501
Buildings	19,939	-	-	-	19,939
Moveable assets	195,595	-	-	-	195,595
Sub-total	232,707	-	-	-	232,707
Total acquisition cost	**27,533,803**	**3,040,347**	**(233,168)**	**(233,571)**	**30,107,411**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2018				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization					
Direct acquisition:					
Oil and gas wells	(6,096,976)	(965,091)	38,038	(52,132)	(7,076,161)
Geothermal wells	(113,904)	(38,223)	-	-	(152,127)
Installations	(2,121,664)	(586,590)	-	(9,548)	(2,717,802)
LPG plants	(179,681)	(113,920)	-	-	(293,601)
Buildings	(36,698)	(11,743)	-	-	(48,441)
Moveable assets	(214,002)	(30,358)	-	-	(244,360)
Sub-total	(8,762,925)	(1,745,925)	38,038	(61,680)	(10,532,492)
Finance lease assets:					
Installations	(16,695)	(2,028)	-	-	(18,723)
LPG plants	(5,469)	(308)	-	-	(5,777)
Buildings	(18,198)	(324)	-	-	(18,522)
Moveable assets	(181,118)	(280)	-	-	(181,398)
Sub-total	(221,480)	(2,940)	-	-	(224,420)
Total accumulated depreciation, depletion and amortization	**(8,984,405)**	**(1,748,865)**	**38,038**	**(61,680)**	**(10,756,912)**
Provision for impairment	(518,024)	(218,189)	-	-	(736,213)
Net book values	**18,031,374**				**18,614,286**

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost					
Direct acquisition:					
Land and land rights	17,651	-	-	592	18,243
Oil and gas wells	10,936,067	2,030,494	(172,042)	1,121,055	13,915,574
Geothermal wells	473,810	-	-	197,785	671,595
Installations	6,345,909	138,748	(144)	729,365	7,213,878
LPG plants	1,435,050	-	-	103,316	1,538,366
Buildings	139,738	2,054	-	31,392	173,184
Moveable assets	306,208	9,942	-	30,805	346,955
Sub-total	19,654,433	2,181,238	(172,186)	2,214,310	23,877,795
Assets under construction					
Exploratory and evaluation wells	1,851,229	463,671	(85,882)	(902,593)	1,326,425
Development wells	1,769,156	1,190,713	-	(862,993)	2,096,876
Sub-total	3,620,385	1,654,384	(85,882)	(1,765,586)	3,423,301
Finance lease assets:					
Installations	21,260	-	(16,588)	-	4,672
LPG plants	28,163	-	-	(15,662)	12,501
Buildings	19,962	-	-	(23)	19,939
Moveable assets	195,572	-	-	23	195,595
Sub-total	264,957	-	(16,588)	(15,662)	232,707
Total acquisition cost	**23,539,775**	**3,835,622**	**(274,656)**	**433,062**	**27,533,803**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2017				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization					
Direct acquisition:					
Oil and gas wells	(4,582,073)	(914,618)	103,496	(703,781)	(6,096,976)
Geothermal wells	(81,462)	(32,442)	-	-	(113,904)
Installations	(1,592,282)	(529,382)	-	-	(2,121,664)
LPG plants	(105,817)	(58,200)	-	(15,664)	(179,681)
Buildings	(26,761)	(9,937)	-	-	(36,698)
Moveable assets	(176,852)	(37,150)	-	-	(214,002)
Sub-total	(6,565,247)	(1,581,729)	103,496	(719,445)	(8,762,925)
Finance lease assets:					
Installations	(31,060)	(2,223)	16,588	-	(16,695)
LPG plants	(20,517)	(617)	-	15,665	(5,469)
Buildings	(17,787)	(411)	-	-	(18,198)
Moveable assets	(180,831)	(287)	-	-	(181,118)
Sub-total	(250,195)	(3,538)	16,588	15,665	(221,480)
Total accumulated Depreciation, depletion and amortization	**(6,815,442)**	**(1,585,267)**	**120,084**	**(703,780)**	**(8,984,405)**
Provision for impairment	(326,671)	(234,614)	43,261	-	(518,024)
Net book values	**16,397,662**				**18,031,374**

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Acquisition cost					
Direct acquisition:					
Land and land rights	13,534	-	-	4,117	17,651
Oil and gas wells	10,436,456	2,700	(129,637)	626,548	10,936,067
Geothermal wells	220,559	-	-	253,251	473,810
Installations	4,873,154	294,576	(1,400)	1,179,579	6,345,909
LPG plants	1,297,778	-	-	137,272	1,435,050
Buildings	79,319	-	-	60,419	139,738
Moveable assets	262,695	8	-	43,505	306,208
Sub-total	17,183,495	297,284	(131,037)	2,304,691	19,654,433
Assets under construction					
Exploratory and evaluation wells	2,275,234	973,555	(22,437)	(1,375,123)	1,851,229
Development wells	2,047,230	541,176	(25,091)	(794,159)	1,769,156
Sub-total	4,322,464	1,514,731	(47,528)	(2,169,282)	3,620,385
Finance lease assets:					
Installations	74,804	-	(15,977)	(37,567)	21,260
LPG plants	44,218	-	(6,591)	(9,464)	28,163
Buildings	19,962	-	-	-	19,962
Moveable assets	195,572	-	-	-	195,572
Sub-total	334,556	-	(22,568)	(47,031)	264,957
Total acquisition cost	**21,840,515**	**1,812,015**	**(201,133)**	**88,378**	**23,539,775**

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

	December 31, 2016				
	Beginning balance	Additions	Deductions	Transfers/ Reclassifications	Ending balance
Accumulated depreciation, depletion and amortization					
Direct acquisition:					
Oil and gas wells	(3,531,941)	(1,053,549)	43,899	(40,482)	(4,582,073)
Geothermal wells	(62,993)	(18,469)	-	-	(81,462)
Installations	(1,131,437)	(366,024)	105	(94,926)	(1,592,282)
LPG plants	(37,789)	(68,028)	-	-	(105,817)
Buildings	(19,611)	(7,150)	-	-	(26,761)
Moveable assets	(141,194)	(35,658)	-	-	(176,852)
Sub-total	(4,924,965)	(1,548,878)	44,004	(135,408)	(6,565,247)
Finance lease assets:					
Installations	(242,247)	(22,645)	15,977	217,855	(31,060)
LPG plants	(35,955)	(616)	6,591	9,463	(20,517)
Buildings	(17,289)	(498)	-	-	(17,787)
Moveable assets	(241)	(302)	-	(180,288)	(180,831)
Sub-total	(295,732)	(24,061)	22,568	47,030	(250,195)
Total accumulated depreciation, depletion and amortization	**(5,220,697)**	**(1,572,939)**	**66,572**	**(88,378)**	**(6,815,442)**
Provision for impairment	(140,055)	(186,616)	-	-	(326,671)
Net book values	**16,479,763**				**16,397,662**

The allocation of depreciation, depletion and amortization expenses are as as follows:

	For the three-month period ended March 31, 2019 (unaudited)	For the years ended December 31,		
		2018	2017	2016
Upstream production and lifting costs (Note 33)	484,736	1,741,040	1,578,988	1,568,663
General and administrative expenses (Note 37)	2,000	7,825	6,279	4,276
Total	**486,736**	**1,748,865**	**1,585,267**	**1,572,939**

As of March 31, 2019, and December 31, 2018, 2017, and 2016, all of the PGE's, PEP, and PGN geothermal properties, except land and land rights, were insured against fire and other possible risks (Note 13).

Management believes that the insurance coverage is adequate to cover any possible losses that may arise in relation to the insured oil and gas and geothermal properties.

PGE's interest was capitalized as part of geothermal properties amounted to US$6,416, and US$24,885, US$32,338 and US$33,098 as of March 31, 2019, and December 31, 2018, 2017, and 2016, respectively.

The increase in the value of oil and gas wells in 2018 and 2017 respectively, resulted from the payment of the Block Rokan signature bonus (Note 4g) and the consolidation of Maurel et Prom's Etablissements.

Impairment of oil and gas properties
Management performed impairment testing of all Blocks due to external indication from the oil price trends. Management has performed technical and commercial evaluations based on the result of recent production. Management evaluates the commercial and technical aspects based on the current price conditions and production.

14. OIL AND GAS AND GEOTHERMAL PROPERTIES (continued)

Estimated recoverable amounts and book values of the oil and gas properties impaired as of March 31, 2019, and December 31, 2018, 2017, and 2016 are as follows:

	March 31, 2019 (unaudited)				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	853,633	852,672	(961)	-	(961)
PIEP and its subsidiaries	657,479	704,944	47,465	-	47,465
Net book value	**1,511,113**	**1,557,616**	**46,504**	**-**	**46,504**

	December 31, 2018				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	173,488	366,793	193,305	-	193,305
Pertamina EP Cepu ADK	55,046	53,708	(1,338)	-	(1,338)
PT PGN and its subsidiaries	872,528	898,750	26,222	-	26,222
Net book value	**1,101,062**	**1,319,251**	**218,189**	**-**	**218,189**

	December 31, 2017				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	856,112	1,097,805	241,693	6,890	234,803
PIEP and its subsidiaries	740,580	708,003	(32,577)	-	(32,577)
Pertamina EP Cepu	58,888	-	(58,888)	-	(58,888)
Pertamina EP Cepu ADK	8,817	63,864	55,047	-	55,047
PT PGN and its subsidiaries	842,735	835,703	(7,032)	-	(7,032)
Net book value	**2,507,132**	**2,705,375**	**198,243**	**6,890**	**191,353**

	December 31, 2016				
	Estimated recoverable amount	Book value	Estimated impairment loss (recovery)	Impairment loss (recovery) on goodwill	Impairment loss (recovery) in oil and gas and geothermal properties
PHE and its subsidiaries	195,539	249,976	54,437	-	54,437
PIEP and its subsidiaries	799,761	972,115	172,354	136,264	36,090
Pertamina EP Cepu	-	58,888	58,888	-	58,888
PT PGN and its subsidiaries	802,565	839,766	37,201	-	37,201
Net book value	**1,797,865**	**2,120,745**	**322,880**	**136,264**	**186,616**

15. OTHER NON-CURRENT ASSETS

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Restricted funds	949,031	915,221	867,332	635,747
Government contributed assets pending final clarification of status (Note 26)	401,120	401,120	1,361	-
Finance Lease Receivables	226,074	200,770	208,908	222,589
Advances to vendors	131,288	133,406	217,704	71,773
Other receivables - third parties	86,568	80,287	243,786	135,481
Goodwill	53,807	53,807	53,807	60,697
Other receivables related parties (Note 41b)	43,898	64,907	80,349	86,232
Long-term employee receivables	36,114	37,530	45,652	39,828
Assets held but not used for operation	23,441	23,454	24,819	10,210
Land rights costs	18,657	18,917	21,653	21,837
Intangible assets	13,841	13,711	17,771	18,039
Deferred charges	13,536	17,256	92,834	57,864
Prepaid expenses	10,758	65,319	31,601	41,422
Non-free and non-clear assets	1,837	1,837	1,837	1,837
Post-employment benefits	10,185	11,589	9,181	24,695
Others	66,340	46,202	58,875	8,613
Total	**2,086,495**	**2,085,333**	**1,977,470**	**1,436,864**

a. Restricted funds

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
US Dollar accounts				
Government-related entities				
- BRI	286,881	286,789	252,149	225,922
- BNI	50,860	50,016	-	-
- Bank Mandiri	14,732	14,030	47,038	39,290
Third parties				
- JP Morgan	31,087	31,087	24,661	-
- Others	1,191	540	-	-
	384,751	382,462	323,848	265,212
Rupiah accounts				
Government-related entities				
- BRI	300,603	290,500	296,096	212,064
- Bank Mandiri	253,092	233,993	238,692	157,564
- BNI	1,557	840	899	907
- BJB	351	-	-	-
- BTN	351	-	-	-
- BRI Agro	75	-	-	-
Third parties				
- Others	8,251	7,426	7,797	-
	564,280	532,759	543,484	370,535
Total	**949,031**	**915,221**	**867,332**	**635,747**

In accordance with SKK Migas instructions, as of March 31, 2019, and December 31, 2018, 2017, and 2016 PT Pertamina EP deposited for decommissioning funds, site restoration, and other related activities in a joint bank account held by SKK Migas and PT Pertamina EP in BRI and Mandiri in the amounts of US$275,660, US$ 275,660, US$252,501 and US$223,984, respectively. PIEP for PT Pertamina Malaysia EP (“PMEP”) deposited funds for decommissioning, site restoration and other related activities in a joint bank account as of March 31, 2019 and December 31, 2018 in the amount of US$31,087 and US$31,087, respectively.

The Company has created reserves fund for past service liabilities to employees as of March 31, 2019, and December 31, 2018, 2017, and 2016 amounting to Rp7,647,817 million (equivalent to US$536,915), Rp7,534,125 million (equivalent to US$520,277), Rp7,185,952 million (equivalent to US$530,407), and Rp4,911,848 million (equivalent to US$365,574), respectively.

15. OTHER NON-CURRENT ASSETS (continued)

a. Restricted funds (continued)

As of March 31, 2019, and December 31, 2018, 2017, and 2016, restrained fund for Partnership Program amounting to Rp12,174 million (equivalent to US$855), Rp12,174 million (equivalent to US$840), Rp12,174 million (equivalent to US$899), and Rp12,174 million (equivalent to US$907), respectively.

As of March 31, 2019, restrained fund for Community Development Program amounting to Rp112,342 million (equivalent to US$7,887).

Included in restricted cash are time deposits which are used as bank guarantees for operational working contracts in PT Pertamina Bina Medika, and PIEP.

b. Finance lease receivables

This account represents the non-current portion of the finance lease receivables from lease arrangement between PT Kalimantan Jawa Gas ("KJG"), PGN's subsidiaries, and PT Perusahaan Listrik Negara ("PLN") (Persero) in relation to KJG's subsea pipelines and onshore receiving facility on land (Gas Transport Agreement ("GTA") Kalija 1 which is classified as a finance lease transaction.

c. Advances to vendors - net

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Advances to vendors	163,992	166,110	250,408	104,477
Provision for impairment	(32,704)	(32,704)	(32,704)	(32,704)
Net	**131,288**	**133,406**	**217,704**	**71,773**

The Company has recognized a provision for impairment to reduce an advance to vendor for oil tanker construction contract with capacity of 30,000 LTDW between the Company and Zhejiang Chenye Shipbuilding Co. Ltd. Management believes that the provision for impairment is adequate to cover possible losses.

d. Goodwill

	Beginning balance	Addition	Deduction	Ending balance
March 31, 2019 (unaudited)				
PHE ONWJ	53,337	-	-	53,337
PHE Nunukan Company	415	-	-	415
PGN and its subsidiaries	55	-	-	55
Total	**53,807**	**-**	**-**	**53,807**
December 31, 2018				
PHE ONWJ	53,337	-	-	53,337
PHE Nunukan Company	415	-	-	415
PGN and its subsidiaries	55	-	-	55
Total	**53,807**	**-**	**-**	**53,807**
December 31, 2017				
PHE ONWJ	53,337	-	-	53,337
PHE Tuban	4,538	-	(4,538)	-
PGN and its subsidiaries	55	-	-	55
Others	2,767	-	(2,352)	415
Total	**60,697**	**-**	**(6,890)**	**53,807**
December 31, 2016				
COPAL	136,264	-	(136,264)	-
PHE ONWJ	53,337	-	-	53,337
PHE Tuban	4,538	-	-	4,538
PGN and its subsidiaries	55	-	-	55
Others	2,767	-	-	2,767
Total	**196,961**	**-**	**(136,264)**	**60,697**

15. OTHER NON-CURRENT ASSETS (continued)

d. Goodwill (continued)

The goodwill is allocated to the Company's Cash Generating Unit ("CGU") identified.

The Group calculated the recoverable amounts based on fair value less cost to sell model which provides a higher value than the value-in-use calculation. The fair value less cost to sell was determined by using a post-tax discounted cash flows ("DCF") calculation.

The cash flows projections are based on production and development forecast approved by management covering the estimated period of contract including contract extension and future investments to increase output. The period of projections ranges from 3-30 years.

ONWJ, PHE Tuban and Other
The Group acquired PT Medco E&P Tuban (subsequently changed its name to PT PHE Tuban) in 2008 and BP West Java Ltd., (subsequently changed its name to ONWJ Ltd.) in 2009, PT PHE Oil and Gas ("PHE OG") and other acquisition in 2013. The Group has recorded an impairment in the value of goodwill in 2018 amounted to nill and 2017 amounting to US$4,538 and US$2,352 (Note 39), from the PHE Blok Tuban and Ambalat Block, respectively to the carrying value of PHE OG.

PGN and its subsidiaries
In 2013, PT PGAS Telekomunikasi Nusantara ("PGASKOM"), a subsidiary of PGN, acquired 100% equity interest of PT Telemedia Dinamika Sarana ("TDS") with consideration paid amounting to Rp675 million (or equivalent to US$55). PGASKOM recognized goodwill from this acquisition amounting to US$55.

COPAL
Effective on November 27, 2013, the Company acquired 100% shares of COPAL from Burlington Resources International Holdings LLC with consideration paid of US$1,669,892. COPAL is a corporation domiciled in the Caymand Island and hold 65% participating interest in Block 405a Algeria. The Company recognized goodwill from this acquisition in the amount of US$556,703. As of January 1, 2016/December 31, 2015, the Group has recorded impairment loss on COPAL goodwill with total cumulative amount of US$420,439.

The Group has recorded impairment losses on goodwill for the year ended December 31, 2017 and 2016 amounting to US$6,890 from PHE (Block Tuban and Block Ambalat) and US$136,264 from COPAL, respectively.

The key assumption relates to oil and gas price, was projected based on expectation of market development given the volatility in oil prices. The discount rate used reflects risk relating to the relevant oil and gas industry and considering risks of individual country of operations.

Key assumptions used for the basis of the impairment test on March 31, 2019 are as follows:

	Assumptions 2019				
	2019 (unaudited)	2020	2021	2022	2023
Projected ICP	US$64.10	US$66.70	US$65.00	US$64.50	US$61.60
Projected Brent	US$67.50	US$70.00	US$68.40	US$67.80	US$65.00

Then increases (decreases) by (US$2.90) - US$2.60 per annum for ICP and (US$2.80) - US$2.50 per annum for Brent

Gas price	Based on the gas sales agreement
Discount rate	6.79%-10.97%

Management believes the goodwill impairment is sufficient based on the result of the impairment testing.

e. Non-free and non-clear assets - net

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Non-free and non-clear assets	112,237	112,237	112,237	112,237
Provision for impairment	(110,400)	(110,400)	(110,400)	(110,400)
Net	**1,837**	**1,837**	**1,837**	**1,837**

15. OTHER NON-CURRENT ASSETS (continued)

e. Non-free and non-clear assets - net (continued)

Non-free and non-clear assets represent land plots located in Teluk Semangka, Lampung and certain assets located in other areas where, as of the date of the completion of these consolidated financial statements, the documentation and rights of the Company were still subject to completion of the legal and settlement processes to allow the Company to fully utilize such assets.

The Company has recognized a provision for impairment to reduce the value of such assets to their recoverable amounts. Management believes that the provision for impairment is adequate.

16. SHORT-TERM LOANS

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Government-related entities (Note 41)				
- Bank Mandiri	1,110,687	1,705,709	166,151	41,937
- BRI	753,287	820,154	189,027	4,434
- BNI	385,410	638,751	340	412
- Others (each bellow US$10,000)	153	110	-	726
Third parties				
- The Bank of Tokyo Mitsubishi UFJ, Ltd. (“BOTM”)	329,281	-	-	-
- PT Bank Mizuho Indonesia	203,272	203,272	10,000	-
- PT ANZ Panin Bank	139,491	139,491	-	-
- PT Bank Sumitomo Mitsui Indonesia	120,000	145,368	-	50,000
- Sumitomo Mitsui Banking Corporation	114,934	97,016	10,000	6,425
- The Hongkong and Shanghai Banking Corp (“HSBC”)	106,244	67,075	-	-
- Citibank,N.A	100,798	145,344	-	-
- Deutsche Bank AG	93,970	93,970	32,285	39,761
- PT Bank UOB Indonesia	77,158	-	10,000	10,000
- PT Bank DBS Indonesia	68,919	86,842	-	50,952
- PT Bank Permata Tbk	59,804	59,804	-	-
- PT Bank ICBC Indonesia	7,649	23,974	27,292	25,642
- PT Bank CIMB Niaga	-	-	5,735	-
- BNP Paribas	-	-	1,329	-
- BCA	-	118,934	-	4
- Others (each bellow US$10,000)	340	1,221	720	-
Total	**3,671,397**	**4,347,035**	**452,879**	**230,293**

Other information relating to the Group’s short-term bank loan facilities as of March 31, 2019 are as follows:

Lenders	Expiration date
Bank Mandiri	September 19, 2019
BNI	June 14, 2019
BRI	November 25, 2019
The Bank of Tokyo-Mitsubishi UFJ, Ltd. (“BOTM”)	November 25, 2019
Citibank, N.A.	May 8, 2019
PT Bank UOB Indonesia	September 23, 2018
BNI Syariah	May 31, 2019
PT Bank Mizuho Indonesia	September 25, 2019
PT Bank Sumitomo Mitsui Indonesia	October 31, 2019
Sumitomo Mitsui Banking Corporation	June 26, 2019
PT ANZ Panin Bank Indonesia Tbk	June 17, 2019
PT Bank Permata Tbk	May 10, 2019
PT Bank DBS Indonesia	July 5, 2019
Deutsche Bank AG	June 19, 2019
The Hongkong and Shanghai Banking Group (“HSBC”)	September 17, 2019
PT Bank Danamon Indonesia Tbk	December 31, 2019
PT Bank ICBC Indonesia	December 31, 2019

Interest rates charged are based on market rates (e.g. Singapore Interbank Offered Rate (“SIBOR”) or London Interbank Offered Rate (“LIBOR”)) plus certain percentage depending on negotiation at drawdown.

16. SHORT-TERM LOANS (continued)

The interest rates on short-term loans for the three-month periods ended March 31, 2019 and for the years ended December 31, 2018, 2017, and 2016 are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
US dollar	2.98%-3.71%	2.76%-3.71%	1.42%-2.52%	1.44%-1.65%
Rupiah	7.25%-12.00%	7.25%-11.50%	6.40%-12.50%	5.19%-12.75%

The funds received from short-term loans are to be used for working capital purposes.

17. TRADE PAYABLES - THIRD PARTIES

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
US dollar	2,744,568	3,215,103	3,719,566	3,050,556
Rupiah	485,902	374,194	152,548	213,848
Others	6,064	8,480	28,007	26,261
Total	**3,236,534**	**3,597,777**	**3,900,121**	**3,290,665**

The Group's trade payables are mainly related to purchases of crude oil, natural gas and petroleum products.

18. DUE TO THE GOVERNMENT

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
The Company:				
Conversion account (amount due to the Government for its share in the Indonesian crude oil production supplied to the Company's refineries)	1,456,127	961,481	749,956	586,171
Ulubelu and Lahendong geothermal project loan	253,310	253,310	252,123	200,777
Lumut Balai geothermal project loan	89,207	84,594	47,590	36,798
The Government's share in the domestic natural gas sales including its share of Indonesian gas production	26,900	36,889	30,674	29,470
Payable for purchase of the Government's share in the LPG production	4,370	11,358	8,826	5,939
Ngurah Rai Airport refuelling facility construction project loan	4,490	4,505	5,152	5,697
Due to BPH Migas for retribution fee from distribution of BBM - non subsidy	-	-	-	4,163
Other liability	-	-	174,907	209,175
Total - Company	**1,834,404**	**1,352,137**	**1,269,228**	**1,078,190**
Subsidiaries:				
PT Pertamina EP				
Government's share of production	29,268	25,764	1,897	15,867
Finance lease liability state-owned assets	86,513	81,815	88,536	90,218
Sub-total	115,781	107,579	90,433	106,085
PT Pertamina Hulu Energi				
Overlifting payables	42,201	37,878	59,678	59,347
PT Pertamina Hulu Indonesia				
Overlifting payables	137,925	109,126	-	-
PT Pertamina EP Cepu				
Overlifting payables	-	-	-	18,875

18. DUE TO THE GOVERNMENT (continued)

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Subsidiaries:				
PT Perusahaan Gas Negara Tbk				
Loan for the construction of gas transmission pipelines from South Sumatera to West Java and distribution pipelines in West Java	344,657	352,971	360,034	362,178
Domestic Gas market development project loan	33,950	36,008	39,996	43,816
Gas transmition and distribution project Phase II project loan	7,126	7,126	11,876	16,627
Total - Subsidiaries	**681,640**	**650,688**	**562,017**	**606,928**
Total consolidated (Note 41)	**2,516,044**	**2,002,825**	**1,831,245**	**1,685,118**
Current portion	**(1,725,693)**	**(1,207,743)**	**(1,050,619)**	**(952,545)**
Non-current portion	**790,351**	**795,082**	**780,626**	**732,573**

a. Conversion account

The conversion account represents the Company's liability to the Government in relation to the shipment of the Government's share of Indonesian crude oil production to the Company's refineries for processing to meet the domestic demand for fuel products. The Government's share in the production of Indonesian crude oil derives from the work area of the PSC Contractor.

The movements of the conversion account are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	961,481	749,956	586,171	341,062
Add:				
Current year's Government share in the Indonesian crude oil production delivered to the Company's refineries during the year	2,701,410	10,289,631	6,819,294	4,726,374
Less:				
Cash settlement	(1,991,946)	(10,029,737)	(6,641,271)	(4,455,821)
Gains on foreign exchange	(214,818)	(48,369)	(14,238)	(25,444)
Ending balance	**1,456,127**	**961,481**	**749,956**	**586,171**

b. Ulubelu and Lahendong Geothermal project loan

For the implementation of Ulubelu and Lahendong Geothermal Clean Energy Investment Project, the Company has obtained loans from the International Bank for Reconstruction and Development ("IBRD") as part of the World Bank Loan.

On December 5, 2011, LA 8082-ID and TF10417-ID were signed by the Government of Indonesia and IBRD with the Company as Executing Agency and PGE as Implementing Agency, with total amount of US$300,000 consisting of LA 8082-ID of US$175,000 and LA TF10417-ID of US$125,000. Interest rate from World Bank is at LIBOR + 0.45% + 0.5% (bank charges) + variance spread annually, while interest rate from Japan International Cooperation Agency ("JICA") is at 0.25% + 0.25%.

Repayment of the loan principal will be on a semi-annual basis, on April 10 and October 10, LA-8082-ID, from October 10, 2020 until October 10, 2035 and LA TF10417-ID, from October 10, 2021 until April 10, 2051.

18. DUE TO THE GOVERNMENT (continued)

b. Ulubelu and Lahendong Geothermal project loan (continued)

The following are the oustanding loan balances as of March 31, 2019 and December 31, 2018, 2017, and 2016:

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
LA 8082-ID	129,044	129,044	131,055	108,947
LA TF10417-ID	124,266	124,266	121,068	91,830
Total	**253,310**	**253,310**	**252,123**	**200,777**

c. Lumut Balai Geothermal project loan

On March 29, 2011, the Loan Agreement ("LA") IP-557 was signed between the Government of Indonesia, represented by the Director General of Debt Management, Ministry of Finance, and JICA, represented by the Chief Representative of JICA, with the Company as Executing Agency and PGE as Implementing Agency. The amount of the loan facility is ¥26,966,000,000 (full amount) with drawing period of eight years from the effective date with effective interest rates at 0.3% p.a plus 0.3% p.a and 0.01% p.a plus 0.01% p.a, respectively.

Repayment of the loan principal will be on a semi-annual basis, on March 20, and September 20, commencing on March 20, 2021 to March 2051. The outstanding loan balance as of March 31, 2019, and December 2018, 2017, and 2016 amounted to ¥9,883,692,974, ¥9,343,033,479, ¥5,363,082,289, and ¥4,284,146,996 (full amount), respectively or equivalent to US$89,207, US$84,594, US$47,590, and US$36,798, respectively.

d. Ngurah Rai Airport refueling facility construction project loan

On May 7, 2007, the Government channelled a loan amounting to ¥1,172,872,837 (full amount) from the Overseas Economic Cooperation Fund Japan to the Company in relation to the construction of the Ngurah Rai Airport refuelling facility in accordance with the loan agreement dated November 29, 1994.

The loan is repayable in 36 semi-annual installments commencing in May 2007 through November 2024, and is subject to interest at the rate of 3.1% per annum. The outstanding loan balance as of March 31, 2019 and December 31, 2018, 2017, and 2016 amounted to ¥497,492,834, ¥497,492,834, ¥580,408,306, and ¥663,323,781 (full amount), respectively, or equivalent to US$4,490, US$4,505, US$5,152, and US$5,697, respectively.

e. Other liability

In 2017, the Company recorded reimbursement of disparity in price of JBKP Premium in 2016, which resulted in additional revenue amounting to Rp2.37 trillion (equivalent to US$174,907 as of December 31, 2017 and US$209,175 as of December 31, 2016) (value before VAT and PBBKB) in accordance with LHP BPK No. 39/AUDITAMA VII/PDTT/11/2017 dated November 13, 2017.

On June 8, 2018, the Government through MoF issued a letter Number S-100/MK.2/2018 regarding Submission of Settlement of Follow-Up Recommendations of the BPK RI in LHP on Central Government Financial Reports ("LKPP") and State General Treasurer Financial Reports (" LKBUN ") in 2015-2017 and LHP for Examinations with Specific Purpose at the Ministry of Finance in 2015-2016, stated that the excess revenue due to price disparity in 2016 JBKP Premium sales was recognized as excess revenue for the Company. This resulted in an amount of Rp2.37 trillion (equivalent to US$178,070) which was previously recorded as due to the Government that corrected to other operating activities revenue in 2018 (Note 31).

f. Finance lease liability involving state-owned assets utilized by PT Pertamina EP

In accordance with the Minister of Finance Decree dated May 2, 2008, assets previously owned by the former Pertamina Entity which have not been recognized in the opening balance sheet of the Company, represent state-owned assets ("BMN"), the control of which is exercised by the Directorate General of State Assets.

On September 20, 2016, the State Property Lease Agreements between the Ministry of Finance of the Republic of Indonesia with PT Pertamina EP No. PRJ-3-MK.6/2016 and No. 1307/EP0000/2016-S0 have been signed. With the signing of the agreements, management believes that the property lease payable for unutilized BMN, will not be charged by the Government since it was not included as part of the scope of the agreements. Therefore, in 2016, PT Pertamina EP made correction to the BMN lease payable for BMN which are not used by PT Pertamina EP.

18. DUE TO THE GOVERNMENT (continued)

f. Finance lease liability involving state-owned assets utilized by PT Pertamina EP (continued)

The following table represents the finance lease payables to BMN that include installations, buildings, and moveable equipment utilized in the PT Pertamina EP's oil and gas operations:

Lessor	Type of asset	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
The Ministry of Finance	Installation assets, buildings and moveable assets	86,513	81,815	88,536	90,218
Less current portion		(4,884)	(1,180)	(1,087)	(944)
Non-current portion		**81,629**	**80,635**	**87,449**	**89,274**

Future minimum lease payments as of March 31, 2019, and December 31, 2018, 2017, and 2016, are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Within one year	14,548	14,310	15,295	15,423
More than one year but not more than five years	72,738	71,550	76,475	77,112
More than five years	156,387	153,832	179,716	196,637
Total	243,673	239,692	271,486	289,172
Less interest	(157,160)	(157,877)	(182,950)	(198,954)
Net	86,513	81,815	88,536	90,218
Current portion	(4,884)	(1,180)	(1,087)	(944)
Non-current portion	**81,629**	**80,635**	**87,449**	**89,274**

g. Overlifting payables

The overlifting payables represent subsidiaries' payable to SKK Migas as a result of subsidiaries' actual lifting crude oil and gas being higher than their entitlements for the respective year.

h. Loans for the construction of gas transmission pipelines from South Sumatera to West Java and distribution pipelines in West Java

On March 27, 2003, Japan Bank for International Cooperation ("JBIC") agreed to provide loans to the Government with a total amount equivalent to ¥49,088,000,000 (full amount) to assist the Government in financing the construction of a gas transmission pipeline network from South Sumatra to Java West and distribution pipelines in West Java.

On May 28, 2003, PGN and the Government entered into a Loan Forwarding Agreement No. SLA1156 / DP3 / 2003, where the Government continues this loan from JBIC with a total not exceeding ¥49,088,000,000 (full amount) to PGN.

The loan principal is repayable on semi-annually basis on March 20 and September 15 starting from March 20, 2013 to March 20, 2043. The loan balance as of March 31, 2019, and December 31, 2018, 2017, and 2016 amounted to ¥38,186,297,299, ¥38,983,847,840, ¥40,554,284,480, and ¥42,164,627,000 (full amounts), respectively or equivalent to US$344,657, US$352,971, US$360,034, and US$362,178, respectively.

18. DUE TO THE GOVERNMENT (continued)

i. Domestic Gas market development project loan

Based on the loan agreement dated February 7, 2006, IBRD agreed to provide loan facility to the Government an aggregate amount equivalent to US$80,000 to assist the Government in financing the Domestic Gas Market Development Project.

On April 3, 2006, PGN and the Government entered into the related Subsidiary Loan Agreement, which provides for the Government's relending of the IBRD loan proceeds of US$80,000 to PGN, which shall undertake the Project.

On November 14, 2013, PGN obtained Letter No. 5-786/PU/2013 from Directorate General of Debt Management, Ministry of Finance of the Republic of Indonesia, regarding the approval for the cancellation of the remaining IBRD SLA 1201 loan amounting to US$7,616 starting on February 1, 2013.

The loan principal is repayable on semi-annually basis on February 15, and August 15 starting from April 3, 2006 to February 15, 2026. The loan balance as of March 31, 2019 and December 31, 2018, 2017, and 2016 US$33,950, US$36,008, US$39,996, and US$43,816.

j. Gas transmition and distribution project Phase II project loan

On September 15, 2000, PGN and the Government entered into a Loan Agreement, which provides for the Government's relending of the EIB loan proceeds not exceeding EUR€70,000,000 (full amount) or equivalent to US$54,633 to PGN as part of the financing of the Gas Transmission and Distribution Project Phase II.

Under the Loan Agreement, PGN undertakes among other things, that it shall maintain certain financial covenants for each reporting year-end such as debt to equity ratio of maximum 2:1.

As of March 31, 2019 and December 31, 2018, 2017, and 2016 PGN has complied with all financial ratios required to be maintained under the loan agreements.

Payments towards the principal is done semi-annually on June 15, and December 15. Payment started from December 15, 2015 until June 15, 2020. The loan balances as of March 31, 2019 and December 31, 2018, 2017, and 2016 amounted to US$7,126, US$7,126, US$11,876, and US$16,627, respectively.

19. ACCRUED EXPENSES

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Suppliers and contractors	1,179,890	1,069,409	1,040,540	805,803
Bonuses, incentives and salaries	360,201	441,536	460,779	398,874
Estimated owned retention claim	305,321	286,508	190,458	123,423
Interest on loans	269,729	105,062	68,109	66,120
Employee benefit liabilities due within one year (Note 22b)	230,353	232,994	260,010	202,392
Total	**2,345,494**	**2,135,509**	**2,019,896**	**1,596,612**

20. LONG-TERM LIABILITIES

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Bank loans:				
Government-related entities	178,540	179,361	174,638	211,074
Third parties	1,758,528	1,891,264	2,100,822	3,028,748
	1,937,068	2,070,625	2,275,460	3,239,822
Issuance costs - net	(5,201)	(4,775)	(6,838)	(13,199)
Total bank loans - net	1,931,867	2,065,850	2,268,622	3,226,623
Finance leases	143,347	160,027	207,104	212,486
Total long-term liabilities	**2,075,214**	**2,225,877**	**2,475,726**	**3,439,109**
Current portion	**(423,322)**	**(420,577)**	**(365,959)**	**(722,200)**
Long-term liabilities - net of current portion	**1,651,892**	**1,805,300**	**2,109,767**	**2,716,909**

20. LONG-TERM LIABILITIES (continued)

Annual interest rates on bank loans for the three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016 are as follows:

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Rupiah	2.35%-13.00%	2.35%-13.00%	7.25%-13.00%	9.00%-12.50%
US dollar	1.37%-5.60%	1.37%-5.60%	1.37%-3.51%	1.46%-3.20%

a. Bank loans

Details of the Group's syndicated and bank loans as of March 31, 2019, and December 31, 2018, 2017, and 2016 are as follows:

	March 31, 2019 (unaudited)		
	Total	Current	Non-current
Government-related entities			
Bank Mandiri	19,021	11,350	7,671
PT Bank Syariah Mandiri	9,329	1,959	7,370
BRI	115	115	-
PT Bank BNI Syariah	75	48	27
Other financial institution -			
PT Sarana Multi Infrastruktur (Persero)	150,000	-	150,000
Third parties			
BOTM (Syndicated loan)	1,450,910	334,590	1,116,320
Sumitomo Mitsui Banking Corporation	194,150	10,603	183,547
PT Bank Sumitomo Mitsui Indonesia	69.093	12,316	56,777
PT Bank ICBC Indonesia	44,375	-	44,375
Total	**1,937,068**	**370,981**	**1,566,087**

	December 31,								
	2018			2017			2016		
	Total	Current	Non-current	Total	Non-Current	current	Total	Non-Current	current
Government-related entities									
Bank Mandiri	19,753	10,043	9,710	17,463	15,981	1,482	14,996	2,967	12,029
PT Bank Syariah Mandiri	9,330	-	9,330	-	-	-	-	-	-
BNI	-	-	-	2,715	2,449	266	20,127	19,859	268
BRI	181	181	-	1,725	1,532	193	1,218	1,218	-
PT Bank BNI Syariah	97	70	27	359	255	104	297	147	150
Other financial institution -									
PT Multi Sarana Infrastruktur (Persero)	150,000	-	150,000	150,000	-	150,000	150,000	-	150,000
Lembaga Pembiayaan Ekspor Indonesia	-	-	-	2,376	2,376	-	24,436	7,152	17,284
Third parties									
BOTM (Syndicated loan)	1,609,539	333,569	1,275,970	1,935,000	277,547	1,657,453	1,104,412	123,036	981,376
BNP Paribas	-	-	-	-	-	-	768,900	384,050	384,850
Sumitomo Mitsui Banking Corporation	199,318	10,601	188,717	105,575	10,602	94,973	1,117,426	130,000	987,426
PT Bank Sumitomo Mitsui Indonesia	67,407	9,083	58,324	60,247	7,273	52,974	29,518	-	29,518
PT Bank Mizuho Indonesia	-	-	-	-	-	-	2,438	2,438	-
PT Bank ICBC Indonesia	15,000	-	15,000	-	-	-	-	-	-
Others (each below US$10,000)	-	-	-	-	-	-	6,054	5,701	353
Total	**2,070,625**	**363,547**	**1,707,078**	**2,275,460**	**318,015**	**1,957,445**	**3,239,822**	**676,568**	**2,563,254**

20. LONG-TERM LIABILITIES (continued)

a. Bank loans (continued)

Other information on the Group's syndicated and bank loans as of March 31, 2019 is as follows:

Creditors	Repayment schedule
The Company	
Sumitomo Mitsui Banking Corporation (Long-term loan)	Several installments (2016-2025)
Lembaga Keuangan Lainnya	
PT Sarana Multi Infrastruktur (Persero) (Long-term loan)	Several installments (2015-2025)
BOTM (Syndicated loan)	Several installments (2016-2021)
Subsidiaries	
PT Bank BNI Syariah	
PT Pertamina Trans Kontinental	Several installments (2016-2019)
PT Bank Sumitomo Mitsui Indonesia	
PT Pertamina Trans Kontinental	Several installments (2015-2024)
BOTM (Syndicated loan)	
PT Pertamina Trans Kontinental	Several installments (2018-2023)
PT Bank Mandiri (Persero) Tbk	
PT Pelita Air Service	Several installments (2014-2019)
PT Bank Rakyat Indonesia (Persero) Tbk	
PT Pertamina Patra Niaga	Several installments (2016-2019)
BOTM (Syndicated loan)	
PT Pertamina Internasional Eksplorasi dan Produksi	Several installments (2015-2023)
PT Bank Syariah Mandiri	
PT Pertamina International Shipping	Several installments (2018-2025)
PT Bank Mandiri (Persero) Tbk	
PT Pertamina International Shipping	Several installments (2018-2025)
Sumitomo Mitsui Banking Corporation (Synidcated loans)	
PT Perusahaan Gas Negara Tbk	Several installments (2015-2020)
PT Bank ICBC Indonesia	
PT Elnusa Tbk	Several installments (2018-2023)

These bank loans are obtained to finance the capital expenditures of the Company and/or Subsidiaries' projects, general activities and certain costs relating to the agreement.

As specified by the loan agreements, the borrowers are required to comply with certain covenants, such as financial ratio covenants, no substantial change in the general business of the Company and/or Subsidiaries and not entering into mergers.

The certain subsidiaries' long-term bank loans are collateralised by those subsidiaries' receivables (Note 8) and fixed assets (Note 13).

On December 12, 2017, Etablissements Maurel et Prom entered into a syndicated loan agreement with 2 (two) national banks and 7 (seven) overseas banks. The Bank of Tokyo Mitsubishi UFJ, Ltd., Hong Kong Branch acting as Facility Agent. The syndicated loan facility amount is US$600 million bears interest at LIBOR plus 1.5% and shall be repaid on quarterly basis starting March 2020 to December 2023.

Prior to effective date of the above syndicated loan agreement, on December 11, 2017, as required by syndication loan agreement, PIEP, as Sponsor, Maurel et Prom West Africa SA, as Borrower, and The Bank of Tokyo Mitsubishi UFJ, Ltd. Hongkong Branch as Facility Agent, signed the Sponsor Support Agreement. This Agreement stipulates that if the Borrower fails to fulfill its obligations (Borrower Non-Payment), the Borrower must immediately submit the Sponsor Loan Request Notice to the Sponsor, and the Sponsor is obligated to provide funds to the Borrower for all unsettled obligations including outstanding interest payable. On December 11, 2017, the Company has issued a comfort letter as required in the syndicated bank facilities as discussed above, but not consitute a guarantee in respect of the obligation of PIEP under Sponsor Support Agreement and the Company shall not be construed as acting as a guarantor.

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the Group complied with the covenants as required by the loan agreements.

20. LONG-TERM LIABILITIES (continued)

b. Finance leases

This account represents the Group's future minimum lease payments from finance lease transactions for the LPG Filling and Transport Stations ("SPPBEs"), landing craft transports, BBM and LPG truck tankers, computer servers, gas pipeline installations and LPG plants.

Future minimum lease payments as of March 31, 2019 and December 31, 2018, 2017, and 2016 are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Within one year	66,368	84,137	54,407	55,501
Within more than year but not more than five years	85,694	115,474	121,179	161,754
More than five years	41,381	32,487	49,493	15,496
Total	193,443	232,098	225,079	232,751
Less: interest	(50,096)	(72,071)	(17,975)	(20,265)
Net	143,347	160,027	207,104	212,486
Current portion	(53,795)	(58,722)	(50,008)	(50,562)
Non-current portion	**89,552**	**101,305**	**157,096**	**161,924**

21. BONDS PAYABLE

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
The Company:				
Issued in 2011				
Due in 2021	1,000,000	1,000,000	1,000,000	1,000,000
Due in 2041	500,000	500,000	500,000	500,000
Issued in 2012				
Due in 2022	1,242,000	1,242,000	1,242,000	1,242,000
Due in 2042	1,221,590	1,221,590	1,230,000	1,230,000
Issued in 2013				
Due in 2023	1,615,000	1,615,000	1,615,000	1,615,000
Due in 2043	1,433,261	1,433,261	1,462,500	1,462,500
Issued in 2014				
Due in 2044	1,500,000	1,500,000	1,500,000	1,500,000
Issued in 2018				
Due in 2048	750,000	750,000	-	-
Total	**9,261,851**	**9,261,851**	**8,549,500**	**8,549,500**
Discount	(65,722)	(65,722)	(51,180)	(51,180)
Issuance cost	(27,211)	(27,211)	(23,552)	(23,552)
Amortization of discount and issuance cost during the period/year	29,880	28,608	23,679	17,544
Bonds payable owned by subsidiaries:	(58,250)	(62,000)	(68,500)	(55,000)
Total Company	**9,140,548**	**9,135,526**	**8,429,947**	**8,437,312**
Subsidiaries:				
Senior Unsecured Fixed Rate Notes	1,350,000	1,350,000	1,350,000	1,350,000
SEI Global Bonds	625,000	625,000	625,000	-
Discount and Issuance Cost - net	(15,741)	(16,430)	(19,074)	(14,656)
Total Subsidiaries	**1,959,259**	**1,958,570**	**1,955,926**	**1,335,344**
Total bonds payable	**11,099,807**	**11,094,096**	**10,385,873**	**9,772,656**

21. BONDS PAYABLE (continued)

Other information on the Group's bonds payable as of March 31, 2019 is as follows:

	Nominal Issued Amount	Issuance price	Starting date	Maturity date	Trustee	Interest rate
The Company:						
Issued in 2011						
Due in 2021	1,000,000	98.097%	May 23, 2011	May 23, 2021	HSBC Bank USA, N.A	5.25%
Due in 2041	500,000	98.380%	May 27, 2011	May 27, 2041	HSBC Bank USA, N.A	6.50%
Issued in 2012						
Due in 2022	1,250,000	99.414%	May 3, 2012	May 3, 2022	HSBC Bank USA, N.A	4.88%
Due in 2042	1,250,000	98.631%	May 3, 2012	May 3, 2042	HSBC Bank USA, N.A	6.00%
Issued in 2013						
Due in 2023	1,625,000	100.000%	May 20, 2013	May 20, 2023	The Bank of New York Mellon	4.30%
Due in 2043	1,625,000	100.000%	May 20, 2013	May 20, 2043	The Bank of New York Mellon	5.63%
Issued in 2014						
Due in 2044	1,500,000	100.000%	May 30, 2014	May 30, 2044	The Bank of New York Mellon	6.45%
Issued in 2018						
Due in 2048	750,000	98.061%	Nov. 7, 2018	Nov. 7, 2048	The Bank of New York Mellon	6.50%
Subsidiary:						
Issued in 2014						
Due in 2024	1,350,000	99.037%	May 12, 2014	May 16, 2024	The Bank of New York Mellon	5.13%
Issued in 2017						
Due in 2024	625,000	100.000%	April 26, 2017	May 5, 2024	Citicorp International Limited	4.45%

The Company
The Indenture stipulates that:

- No later than 30 days following the occurrence of an event in which the Government of Indonesia ceases to own, directly or indirectly, more than 50% of the voting securities of the Company (Change of Control Triggering Event), the Company may be required to make an offer to repurchase all senior notes outstanding at a purchase price equal to 101% of their principal amount plus accrued and unpaid interest, if any, to the date of repurchase. The senior notes are subject to redemption in whole, at 100% of their principal amount, together with any accrued interest, at the option of the Company at a certain time in the event of certain changes affecting Indonesian taxation.
- Certain covenants include among others: limitation on liens, limitation on sale and lease back transactions and provision of financial statements and other reports.
- The Company complied with the restrictions specified within the agreements with the Trustee.
- The proceeds from senior notes issued were used to partially fund the capital expenditure requirements in the acquisition of new blocks, development of existing blocks, rig purchase and tanker building.

As of March 31, 2019, the Company was rated as Baa2 with a stable outlook by Moody's Investors Service, BBB with a stable outlook by Fitch Ratings and BBB- with a stable outlook by Standard & Poor's ("S&P").

During the three-month periods ended March 31, 2019, no buy back portions of senior bonds by the Company (for the years ended December 31, 2018: US$37,649).

Subsidiary
- Senior unsecured fixed notes
  In relation to these bonds, the Company is restricted in conducting consolidation, merger, transfer, lease or disposal ofa ll or substantially all of its assets.
  Based on moody's investors services, S&P and Fitch Rating the bonds were rated at Baa3, BB+, and BBB-, respectively.
- SEI senior unsecured fixed rate notes
  SEI is not required to make sinking fund payment with respect ot hese bonds.
  Based on moody's investors services, S&P and Fitch Rating the bonds were rated at Ba1, BB+, and BB+, respecitvely.

22. EMPLOYEE BENEFIT LIABILITIES

a. Post-employment benefit plans and other long-term employee benefits

The Company and certain Subsidiaries have post-employment benefit plans and provide other long-term employee benefits as follows:

1. Post-employment benefit plans

(i) Defined benefit plan managed by Dana Pensiun Pertamina

The Company and certain Subsidiaries received approval from the MoF of the Republic of Indonesia in Decision Letter No. S-190/MK.6/1977 dated July 15, 1977 to establish a separate pension fund, Dana Pensiun Pertamina, from which all employees, after serving a qualifying period, are entitled to defined benefits upon retirement, disability or death, and also post-employment medical benefits. The Defined Benefit Plans ("PPMP") cover employees who were hired before year 2005.

(ii) Post-retirement healthcare benefits

The post-retirement healthcare benefits involve the Company's retired employees and their spouses that had minimum 15 years of services and minimum 46 years old.

(iii) Severance and service pay ("PAP")

PAP benefits consist of additional benefits for employees to which they are entitled when they enter the pension age and in the event of permanent disability, death, or voluntary resignation.

2. Other long-term employee benefits plan

The Company provides other long-term employee benefits in the form of pre-retirement benefits ("MPPK"), repatriation costs, annual leave, the Mandiri Guna I Insurance Program and service anniversaries, except for the insurance program benefit.

3. Employees' saving plan

The Company and certain Subsidiaries (collectively referred to as the Participants) operate an Employees' Saving Plan ("TP") in the form of a defined contribution plan, in which the saving will be received by employees at the end of their service period. Until the fiscal year 2015, all contributions made are managed by PT Pertamina Pedeve Indonesia. Effective on October 28, 2016, PT Pertamina Pedeve Indonesia made a decision to restructure and it is no longer in business activities as a venture capital company so that all of available funds are transferred by management to Pension Fund ("DPLK").

b. Provision for employee benefits

The estimated employee benefits obligations of the Company and most of its Subsidiaries as of December 31, 2018, 2017, and 2016, were determined based on the valuation reports of an independent actuary, PT Dayamandiri Dharmakonsilindo, dated January 9, 2019, January 25, 2018, and January 25, 2017, respectively. The estimated employee benefit obligations of the Company and most of its Subsdiaries as of March 31, 2019 were determined by way of extrapolation of the latest actuarial valuation report. The table below presents a summary of the employee benefits obligations reported in the consolidated statements of financial position:

	As of March 31, 2019 (unaudited)	As of December 31, 2018	2017	2016
The Company:				
Pension and other post employment benefits:				
- PPMP	147,593	142,585	200,990	142,326
- Post-retirement healthcare benefits	812,380	786,489	924,654	832,487
- PAP	723,096	718,902	900,396	922,194
- Repatriation costs	5,645	5,423	8,480	8,230
Sub-total	1,688,714	1,653,399	2,034,520	1,905,237

22. EMPLOYEE BENEFITS LIABILITIES (continued)

b. Provision for employee benefits (continued)

	As of March 31, 2019 (unaudited)	As of December 31,		
		2018	2017	2016
Other long-term employee benefits:				
- MPPK	109,346	104,428	129,278	114,778
- Annual leave and service anniversary	11,580	10,035	16,063	12,843
Sub total	120,926	114,463	145,341	127,621
Subsidiaries:				
Pension and other post-employment benefits	325,896	315,515	288,369	228,266
Total Consolidated	**2,135,536**	**2,083,377**	**2,468,230**	**2,261,124**
Current portion (Note 19)	(230,353)	(232,994)	(260,010)	(202,392)
Non-current portion	**1,905,183**	**1,850,383**	**2,208,220**	**2,058,732**

c. Changes in present value of post-employment benefit obligations and fair value of plan assets

The following tables summarize the components of net benefit expense recognized in the statement of profit or loss and other comprehensive income and the funded status and amounts recognized in the statement of financial position for the respective plans for the three-month periods ended March 31, 2019, and the years ended December 31, 2018, 2017, and 2016 are as follows:

i. Post-employment benefit obligations

	March 31, 2019 (unaudited)						
	PPMP						
	Present value of post-employment benefit obligations	Fair value of plan assets	Post-employment benefit obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	674,493	(531,908)	142,585	786,489	718,902	5,423	1,653,399
Current service cost							
Contribution from employee	369	-	369	2,618	11,155	94	14,236
Interest expense (Interest income)	13,848	(11,148)	2,700	17,255	13,435	105	33,495
Sub-total amounts recognized in profit or loss	**14,217**	**(11,148)**	**3,069**	**19,873**	**24,590**	**199**	**47,731**
Benefits paid from plan asset	(16,064)	16,064	-	-	-	-	-
Benefit paid by the Company	-	-	-	(6,974)	(32,414)	(66)	(39,454)
Contribution to plan by the Company	-	(415)	(415)	-	-	-	(415)
Loss on foreign currency exchange	11,236	(8,882)	2,354	12,992	12,018	89	27,453
Ending balance	**683,882**	**(536,289)**	**147,593**	**812,380**	**723,096**	**5,645**	**1,688,714**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefit obligations (continued)

	December 31, 2018						
	PPMP						
	Present value of post-employment benefit obligations	Fair value of plan assets	Post-employment benefit obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	790,740	(589,750)	200,990	924,654	900,396	8,480	2,034,520
Current service cost							
(Contribution from employee)	3,935	(1,057)	2,878	27,061	48,428	405	78,772
Interest expense							
(Interest income)	55,823	(42,502)	13,321	67,111	50,139	542	131,113
Sub-total amounts recognized in profit or loss	**59,758**	**(43,559)**	**16,199**	**94,172**	**98,567**	**947**	**209,885**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	(67,025)	36,386	(30,639)	(256,537)	(85,986)	(676)	(373,838)
Experience adjustments	2,452	-	2,452	117,720	31,520	(1,715)	149,977
Sub-total expense (income) recognized in other comprehensive income	**(64,573)**	**36,386**	**(28,187)**	**(138,817)**	**(54,466)**	**(2,391)**	**(223,861)**
Benefits paid from plan asset	(61,562)	61,562	-	-	-	-	-
Benefit paid by the Company	-	-	-	(35,241)	(169,620)	(1,107)	(205,968)
Contribution to plan by the Company	-	(34,218)	(34,218)	-	-	-	(34,218)
Loss on foreign currency exchange	(49,870)	37,671	(12,199)	(58,279)	(55,975)	(506)	(126,959)
Ending balance	**674,493**	**(531,908)**	**142,585**	**786,489**	**718,902**	**5,423**	**1,653,399**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefit obligations (continued)

	December 31, 2017						
	PPMP						
	Present value of post-employment benefit obligations	Fair value of plan assets	Post-employment benefit obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	735,775	(593,449)	142,326	832,487	922,194	8,230	1,905,237
Current service cost							
(Contribution from employee)	3,569	(1,266)	2,303	16,809	45,431	534	65,077
Interest expense							
(Interest income)	60,762	(50,168)	10,594	72,036	67,105	654	150,389
Sub-total amounts recognized in profit or loss	**64,331**	**(51,434)**	**12,897**	**88,845**	**112,536**	**1,188**	**215,466**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	80,080	22,798	102,878	166,048	76,914	836	346,676
Experience adjustments	(18,440)	-	(18,440)	(120,215)	(35,473)	(1,111)	(175,239)
Sub-total expense (income) recognized in other comprehensive income	**61,640**	**22,798**	**84,438**	**45,833**	**41,441**	**(275)**	**171,437**
Benefits paid from plan asset	(64,177)	64,177	-	-	-	-	-
Benefit paid by the Company	-	-	-	(34,417)	(168,325)	(590)	(203,332)
Contribution to plan by the Company	-	(36,763)	(36,763)	-	-	-	(36,763)
Loss on foreign currency exchange	(6,829)	4,921	(1,908)	(8,094)	(7,450)	(73)	(17,525)
Ending balance	**790,740**	**(589,750)**	**200,990**	**924,654**	**900,396**	**8,480**	**2,034,520**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

i. Post-employment benefit obligations (continued)

	December 31, 2016						
	PPMP						
	Present value of post-employment benefit obligations	Fair value of plan assets	Post-employment benefit obligations	Post-retirement healthcare benefits	PAP	Repatriation cost	Total
Beginning balance	702,452	(608,993)	93,459	719,791	902,089	8,824	1,724,163
Current service cost							
(Contribution from employee)	4,230	(1,418)	2,812	11,680	45,288	502	60,282
Interest expense							
(Interest income)	64,279	(55,627)	8,652	68,355	77,516	745	155,268
Sub-total amounts recognized in profit or loss	**68,509**	**(57,045)**	**11,464**	**80,035**	**122,804**	**1,247**	**215,550**
Actuarial (gain) loss arising from:							
Changes in financial assumptions	15,564	28,927	44,491	(4,004)	39,711	424	80,622
Experience adjustments	(5,470)	-	(5,470)	45,508	(10,510)	(1,953)	27,575
Sub-total expense (income) recognized in other comprehensive income	**10,094**	**28,927**	**39,021**	**41,504**	**29,201**	**(1,529)**	**108,197**
Benefits paid from plan asset	(63,909)	63,909	-	-	-	-	-
Benefit paid by the Company	-	-	-	(27,171)	(156,042)	(555)	(183,768)
Contribution to plan by the Company	-	(3,667)	(3,667)	-	-	-	(3,667)
Loss on foreign currency exchange	18,629	(16,580)	2,049	18,328	24,142	243	44,762
Ending balance	**735,775**	**(593,449)**	**142,326**	**832,487**	**922,194**	**8,230**	**1,905,237**

On the status of unfunded Defined Benefit Pension Plan ("PPMP") will be settled paid by the Company in accordance with applicable regulations.

The actual return on plan assets as of March 31, 2019 and December 31, 2018, 2017, and 2016 amounted to US$142,207, US$6,116, US$27,369 and US$26,700 respectively.

ii. Other long-term employment benefit

	As of March 31, 2019 (unaudited)		
	MPPK	Annual leave and service anniversary	Total
Beginning balance	104,428	10,035	114,463
Current service cost	1,624	1,305	2,929
Interest cost	2,000	155	2,155
Sub-total benefit cost recognized in the profit or loss	**3,624**	**1,460**	**5,084**
Benefit paid by the Company	(420)	(71)	(491)
Gain on foreign exchange	1,714	156	1,870
Ending balance	**109,346**	**11,580**	**120,926**

22. EMPLOYEE BENEFITS LIABILITIES (continued)

c. Changes in present value of post-employment benefit obligations and fair value of plan assets (continued)

ii. Other long-term employment benefit (continued)

	As of December 31,								
	2018			2017			2016		
	MPPK	Annual leave and service anniver-sary	Total	MPPK	Annual leave and service anniver-sary	Total	MPPK	Annual leave and service anniver-sary	Total
Beginning balance	129,278	16,063	145,341	114,778	12,843	127,621	114,591	13,042	127,633
Current service cost	6,743	3,866	10,609	6,573	7,039	13,612	5,906	5,980	11,886
Past service cost	-	-	-	-	-	-	(304)	(49)	(353)
Interest cost	7,995	802	8,797	8,828	817	9,645	9,699	969	10,668
Actuarial (losses) gain	(18,078)	(3,605)	(21,683)	4,604	864	5,468	2,647	(2,348)	299
Sub-total benefit cost recognized in the profit or loss	**(3,340)**	**1,063**	**(2,277)**	**20,005**	**8,720**	**28,725**	**17,948**	**4,552**	**22,500**
Benefit paid by the Company	(13,453)	(6,138)	(19,591)	(4,367)	(5,353)	(9,720)	(20,850)	(5,106)	(25,956)
(Loss) Gain on foreign exchange	(8,057)	(953)	(9,010)	(1,138)	(147)	(1,285)	3,089	355	3,444
Ending balance	**104,428**	**10,035**	**114,463**	**129,278**	**16,063**	**145,341**	**114,778**	**12,843**	**127,621**

d. Actuarial assumptions

Significant actuarial assumptions applied in the calculation of post-employment benefit obligations and other long-term employment benefits for the Company are as follows:

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Discount rate (per annum):				
- Defined benefits plan administered by Dana Pensiun Pertamina	8.41%	8.41%	7.76%	8.61%
- PAP	8.12%	8.12%	6.44%	7.85%
- Post-retirement healthcare benefits	8.77%	8.77%	7.76%	8.78%
- Repatriation cost	8.29%	8.29%	7.26%	8.57%
- MPPK	8.27%	8.27%	7.07%	8.34%
- Annual leave	7.39%	7.39%	6.35%	7.81%
- Services anniversary	8.30%	8.30%	7.07%	8.50%
Gold Inflation rate (per annum)	8.00%	8.00%	9.00%	9.00%
Salary increases (per annum)	9.50%	9.50%	9.50%	9.50%
Annual medical expense trend (per annum afterwards)	8.00%	8.00%	8.00%	8.00%
Demographic factors:				
- Mortality:	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011	Tabel Mortalitas Indonesia 3-2011 "TMI 3" 2011
- Disability (TMI 3):	0.75% TMI 3	0.75% TMI 3	0.75% TMI 3	0.75% TMI 3
- Resignation:				
Until 20 years of age (per annum)	1%	1%	1%	1%
21-55 years of age (per annum)	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56	reducing linearly to 0% until the age of 56
- Pension	100% at normal retirement age	100% at normal retirement age	100% at normal retirement age	100% at normal retirement age
- Normal retirement age (years)	56 years	56 years	56 years	56 years
- Operational costs of the pension plan:	8% of service cost and 2.11% of benefit payments	8% of service cost and 2.11% of benefit payments	8% of service cost and 2.11% of benefit payments	8% of service cost and 3.5% of benefit payments

22. EMPLOYEE BENEFIT LIABILITIES (continued)

d. Actuarial assumptions (continued)

Investment portfolio of plan assets comprises the following:

	March 31, 2019 (unaudited)		December 31, 2018		2017		2016	
	Investment value	%	Investment value	%	Investment value	%	Investment value	%
Equity instruments	153,862	27%	154,253	29%	171,028	29%	190,834	32%
Debt instruments	245,299	40%	218,082	41%	247,694	42%	256,397	43%
Others	137,130	33%	159,573	30%	171,028	29%	146,218	25%
Total	**536,291**	**100%**	**531,908**	**100%**	**589,750**	**100%**	**593,449**	**100%**

The expected return on plan assets is determined by considering the expected returns from the assets based on current investment policy. Expected yields on fixed interest investments are based on gross redemption yields as of the reporting date. Expected returns on equity and investment properties reflect long-term real rates of return experienced in the respective markets.

Expected contributions to post-employment benefit plans for the three-month periods ended March 31, 2019 and the years ended December 31, 2018, 2017, and 2016, were US$31,685, and US$31,166, US$5,371, and US$5,416, respectively.

The qualitative sensitivity analysis for significant assumptions as of March 31, 2019 is as follows (unaudited):

	Effect on 1% increase to defined benefit obligation	Effect on 1% decrease to defined benefit obligation
Discount rate	(23,459)	23,459
Salary rate	8,497	(8,497)
Healthcare cost trend rate	8,124	(8,124)

The average duration years of the Company's defined benefits plan obligation as of March 31, 2019 and December 31, 2018, 2017, and 2016, are as follows:

	As of March 31, 2019 (unadited)	December 31, 2018	2017	2016
PPMP	14.35	14.35	15.38	15.91
PAP	5.98	5.98	6.71	5.70
Post-retirement healthcare benefits	17.84	17.84	25.57	20.49

The maturity profile of post-employment benefits obligation of the Company as of March 31, 2019 and December 31, 2018, 2017, and 2016, are as follows:

	As of March 31, 2019 (unadited)	December 31, 2018	2017	2016
Within 1 years	270,838	266,405	291,079	262,536
2 - 5 years	805,132	791,955	903,342	855,130
More than 5 years	22,874,445	22,500,076	23,312,066	16,312,066
	23,950,415	**23,558,436**	**24,506,487**	**17,429,732**

Management believes that the estimated liabilities for employee benefits from all of the Group's pension programs, based on the estimated calculation provided by the actuaries, exceed the minimum liability that is required by Labour Law No. 13/2003.

23. PROVISION FOR DECOMMISIONING AND SITE RESTORATION

The movements in the provision for decommissioning and site restoration are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	2,029,735	2,129,337	1,900,093	2,000,069
Addition (deduction) - net	(1,053)	(186,637)	177,746	(182,246)
Accretion expense (Note 38 and 46a)	21,507	87,035	51,498	82,270
Ending balance	**2,050,189**	**2,029,735**	**2,129,337**	**1,900,093**

The addition (deduction) mainly represents the changes in estimate in decommissioning and site restoration which were applied by the Group.

24. NON-CONTROLLING INTERESTS

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
PT Perusahaan Gas Negara Tbk	1,785,815	1,397,957	1,382,334	1,368,449
PT Pertamina Internasional Eksplorasi dan Produksi	332,752	333,294	263,376	-
PT Elnusa Tbk	139,733	134,790	132,956	127,485
PT Asuransi Tugu Pratama Indonesia Tbk (previously PT Tugu Pratama Indonesia)	143,616	143,831	108,797	82,232
Pertamina International Timor S.A.	1,084	1,447	1,086	605
Total	**2,403,000**	**2,011,319**	**1,888,549**	**1,578,771**

25. SHARE CAPITAL, ADVANCE FOR SHARE ISSUANCE AND ADDITIONAL PAID-IN CAPITAL

a. Share capital and advance for share issuance

In accordance with Notarial Deed No. 20 dated September 17, 2003 of Lenny Janis Ishak, S.H., and the decision of MoF through Decision Letter No. 408/KMK.02/2003 (KMK 408) dated September 16, 2003, the Company's authorized capital amounted to Rp200 trillion (full amount), which consists of 200,000,000 ordinary shares with a par value of Rp1,000,000 (full amount) per share of which Rp100 trillion (full amount) has been issued and paid by the Government of the Republic of Indonesia through the transfer of identified net assets from the former Pertamina Entity, including its Subsidiaries and its Joint Ventures.

Based on MoF's Decision Letter No. 23/KMK.06/2008 dated January 30, 2008, regarding the Determination of the Opening Balance Sheet of PT Pertamina (Persero) as of September 17, 2003, the total amount of the Government's equity ownership in the Company is Rp82,57 trillion (full amount). This amount consists of all of the former Pertamina Entity's net assets and net liabilities excluding LNG plants operated by PT Badak Natural Gas Liquefaction and PT Arun Natural Gas Liquefaction, former upstream assets currently operated by PT Pertamina EP, and certain parcels of land and building assets.

The changes in the Company's issued and paid-up share capital from Rp100 trillion to Rp82,57 trillion (equivalent to US$9,809,882) (full amount) were approved at a GMS held on June 15, 2009 and was documented in Notarial Deed No. 11 of Lenny Janis Ishak, S.H. The amendment was documented in Notarial Deed No. 4 dated July 14, 2009 of Lenny Janis Ishak, S.H., and approved by the Minister of Law and Human Rights of the Republic of Indonesia in Decision Letter No. AHU-45429.AH.01.02.Tahun 2009 dated September 14, 2009. The reduction in the Company's issued and paid-up share capital is effective retrospectively as of September 17, 2003.

As of August 1, 2012, there were additional share capital contributions documented in Notarial Deed No. 1 of Lenny Janis Ishak, S.H. in the amount of Rp520.92 billion (full amount) (equivalent to US$55,019) and based on PP No. 13 Year 2012 regarding the Addition to the Government's Capital Contribution to Share Capital of State Enterprise (Persero) PT Pertamina.

25. SHARE CAPITAL, ADVANCE FOR SHARE ISSUANCE AND ADDITIONAL PAID-IN CAPITAL (continued)

a. Share capital and advance for share issuance (continued)

Based on the GMS dated December 14, 2015, the MoSOE approved the capitalization of retained earnings into share capital amounting to Rp50 trillion with 50,000,000 shares (full amount) (equivalent to US$3,552,146).

Subsequently, advances for share issuance was capitalized as an addition to issued and paid-up share capital through Notarial Deed No. 10 dated January 11, 2016 of Lenny Janis Ishak, S.H.

The additional issued and paid-up share capital was reported to the Minister of Law and Human Rights through Receipt of Notification regarding the Amendment of Articles of Association No. AHU-AH.01.3-0003113 dated January 15, 2016.

The increase in the Company's authorized capital from Rp200 trillion to Rp600 trillion (full amount) has been approves by MoSOE as the GMS of the Company through Approval letter No. S-217/MBU/04/2018 dated April 11, 2018 and was documented in Notarial Deed No. 29 dated April 13, 2018 of Aulia Taufani, S.H., and approved by the Minister of Law and Human Rights of the Republic of Indonesia in Decision Letter No. AHU-0052766.AH.01.11.Tahun 2018 dated April 13, 2018 (Note 4a).

As of March 31, 2019, and December 31, 2018, 2017, and 2016, the Company's issued and paid-up share capital were as follows:

Shareholder	Number of isssued and paid-up shares (full amount)	Percentage of ownership	Issued and paid up share capital
March 31, 2019 (unaudited)			
The Government of the Republic of Indonesia	171,227,044	100%	16,191,204
December 31, 2018			
The Government of the Republic of Indonesia	171,227,044	100%	16,191,204
December 31, 2017			
The Government of the Republic of Indonesia	133,090,697	100%	13,417,047
December 31, 2016			
The Government of the Republic of Indonesia	133,090,697	100%	13,417,047

b. Additional paid-in capital

The additional paid-in capital as of March 31, 2019 and December 31, 2018, 2017, and 2016 represent the effect of applying of SFAS 38, Business Combination of Entities Under Common Control (Revised 2012), to recognize the difference between the consideration received/transferred and the amount recorded.

26. GOVERNMENT CONTRIBUTED ASSETS PENDING FINAL CLARIFICATION OF STATUS ("BPYBDS")

a. Refuelling apron installation at Sultan Hasanuddin-Makassar Airport and fuel hydrant facilities at Juanda-Surabaya Airport

Based on Memorandum of Operational Acceptances ("MOACs") No. 05/BA/MKS-HND/XII/2011, No. AU/14525/KEU.1227/XII/2011, No. BA084/F100000/2011-S3 and MOACs No. 005/F00000/2012-S0, No. BA.125 Year 2012, No. 0573/B3/KOBU/IV/2012 from the Ministry of Transportation, the Company obtained management and operation rights of Refuelling Apron Installation at Sultan Hasanuddin Airport-Makassar and Fuel Hydrant Facilities at Juanda Airport-Surabaya, resulting in the balance of this account of Rp12,453 million (equivalent to US$1,361) (Note 15) on December 31, 2017.

26. GOVERNMENT CONTRIBUTED ASSETS PENDING FINAL CLARIFICATION OF STATUS (“BPYBDS”) (continued)

b. Natural gas distribution network ("jargas") for households and gas refueling stations ("SPBG") and supporting infrastructure

As of December 31, 2018, the Company and Secretary General of the Directorate of Oil and Gas of the Ministry of Energy and Mineral Resources as the proxy of budget/goods users have signed the Minutes of Handover of Operations. Use ("BASTO") of State Property ("BMN") in the form of Distribution Network ("Jargas") Natural Gas for Households Number BA-05/C00000/2018-S0 and Gas Filling Stations ("SPBG") and Infrastructure Supporting Number BA-06/C00000/2018-S0. The value of BMN assets in the form of land and non-land assets with categories of operating and non-operating assets is Rp5.8 trillion (equivalent to US$399,759) (Note 15), currently these assets are managed by PT Pertagas Niaga and PGN.

Based on the results of the discussion of the Ministry of Finance, the Ministry of Energy and Mineral Resources, the Financial and Development Supervisory Agency ("BPKP"), and the Company agreed that BASTO was recorded and treated as BPYBDS and recorded in other asset accounts. Based on the results of the review of BPKP assets of Jargas and SPBG with free and clear status, it will be recommended to carry out the State Capital Participation ("PMN") process, while those that do not have free and clear status will be returned to the ESDM Directorate General of Oil and Gas.

27. RETAINED EARNINGS AND INTERIM DIVIDEND

a. General Meeting of Shareholders (“GMS”)

On May 31, 2016, the Company held a GMS for the fiscal year 2015. Based on the minutes of meeting, the shareholders approved, among other, the utilization of 2015 net income of the Company as follows:
- Distribution of dividends amounting to Rp6.8 trillion (equivalent to US$499,449); (Note 46)
- The remaining amount of US$920,771 were reserved to support operations and corporate development.

Based on the GMS decision to approve the 2015 annual report of PT Pertamina (Persero), there was an additional appropriation of retained earnings for partnership program and community development program mounting to Rp57,480 million (equivalent to US$4,222) and Rp57,480 million (equivalent to US$4,222), respectively.

On March 16, 2017, the Company held a GMS for the fiscal year 2016. Based on the minutes of meeting, the shareholder approved, among others, the utilization of 2016 net income of the Company as follows:
- Distribution of dividends amounting to Rp12.1 trillion (equivalent to US$907,383); (Note 46)
- The remaining amount of US$2,239,660 were reserved to support operations and corporate development.

Based on the GMS decision to approve the 2017 Company Workplan and Budget (“RKAP”) of the Company, there was an additional appropriation of retained earnings for community development program amounting to Rp250 billion (equivalent to US$18,707).

On January 17, 2018 based on the GMS decision to approve the 2018 RKAP of the Company, there was an additional appropriation of retained earnings for community development program amounting to Rp275 billion (equivalent to US$19,936).

On May 2, 2018, the Company held a GMS for the fiscal year 2017. Based on the minutes of meeting, the shareholders approved, among other things, the utilization of 2017 net income of the Company as follows:
- Distribution of dividends amounting to Rp8.57 trillion (equivalent to US$614,939); (Note 46)
- The remaining amount of US$1,925,256 were reserved to support operations and corporate development.

On January 23, 2019 based on the GMS decision to approve the 2019 RKAP of the Company, there was an additional appropriation of retained earnings for community development program amounting to Rp124.7 billion (equivalent to US$8,921).

b. Interim dividend

In 2016, the Company paid an interim dividend for 2016 to the Government amounting to Rp500,000 million (full amount) (equivalent to US$37,120) based on a request from the Minister of State-Owned Enterprises to President Director through Letter No. S-719/MBU/12/2016 dated December 6, 2016.

The interim dividend payments in 2016 have been recognized as advances as of December 31, 2016.

28. DOMESTIC SALES OF CRUDE OIL, NATURAL GAS, GEOTHERMAL ENERGY AND OIL PRODUCTS

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Pertamax, Pertamax plus, Pertalite gasoline and Pertadex (diesel oil)	2,641,124	2,940,853	11,215,914	9,794,161	2,388,025
ADO	2,391,210	2,222,795	10,713,543	9,388,019	8,557,555
Natural gas	1,606,548	1,680,621	3,196,038	5,461,178	5,607,942
Premium gasoline	1,216,293	1,047,760	4,509,233	5,429,272	11,488,509
LPG, Petrochemicals, Lubricants and Others	1,057,769	1,236,100	8,201,023	4,313,150	3,618,572
Avtur and Avigas	783,262	893,313	3,955,434	2,990,276	2,356,815
Crude oil	162,464	223,978	917,333	763,281	335,148
Geothermal energy-steam and Electricity	157,426	156,343	645,593	609,610	524,879
IFO/MFO	140,476	146,078	639,575	492,753	450,635
DMO fees - crude oil	130,989	130,989	612,953	400,621	355,699
Kerosene	28,632	32,383	123,894	137,924	144,135
IDO	1,800	2,786	11,978	8,539	13,782
Total	**10,317,993**	**10,713,999**	**44,742,511**	**39,788,784**	**35,841,696**

29. SUBSIDY REIMBURSEMENTS FROM THE GOVERNMENT

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Current year:					
Subsidy reimbursements for 3 kg LPG cylinders (Note 9b)	675,269	792,080	3,496,603	2,977,967	1,817,647
Subsidy reimbursements for certain fuel (BBM) products (Note 9c)	520,120	551,094	2,126,796	595,206	753,250
Subsidy reimbursements for kerosene (Note 9)	17,108	-	16,828	-	-
Sub total	1,212,497	1,343,174	5,640,227	3,573,173	2,570,897
Corrections from govenrment audit for subsidy reimbursements:					
- BBM year 2018 (Note 9c)	-	(149)	(699)	-	-
- LPG year 2018 (Note 9b)	-	(261)	(1,252)	-	-
- BBM year 2017 (Note 9c)	-	-	(147)	-	-
- LPG year 2017 (Note 9b)	-	-	(5,661)	-	-
- BBM year 2016 (Note 9c)	-	-	-	(605)	-
- LPG year 2016 (Note 9b)	-	-	-	(484)	-
- BBM year 2015 (Note 9c)	-	-	-	-	(1,574)
- LPG year 2015 (Note 9b)	-	-	-	-	(479)
Sub total	-	(410)	(7,759)	(1,089)	(2,053)
Total	**1,212,497**	**1,342,764**	**5,632,468**	**3,572,084**	**2,568,844**

Any difference in subsidy reimbursement between the amount recorded in the books and the results of BPK's and other Government body audit is adjusted in the period when the audit report is received.

30. EXPORT OF CRUDE OIL, NATURAL GAS AND OIL PRODUCTS

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Oil products	446,459	237,904	1,811,257	968,882	624,030
Crude oil	269,034	233,114	1,187,824	659,722	172,939
Natural gas	151,841	276,922	637,872	245,677	171,402
Total	**867,334**	**747,940**	**3,636,953**	**1,874,281**	**968,371**

31. REVENUES FROM OTHER OPERATING ACTIVITIES

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Disparity of Selling Price (Notes 9a and 18e)	-	-	3,102,218	-	-
Upstream support services	47,204	52,626	156,869	155,442	113,780
Transport and technical services	45,071	52,031	13,359	8,994	43,024
Shipping services	35,502	26,649	127,010	124,224	186,489
Insurance services	33,571	27,002	84,585	98,870	9,055
Health and hospital services	21,843	19,763	76,607	85,383	71,427
Office and hospitality services	17,056	8,429	26,155	23,656	3,163
Natural gas transport services	17,025	49,448	204,140	151,916	167,313
Human resources provision and development services	16,435	18,280	4,825	2,026	2,850
Regasification services	12,640	2,340	31,108	19,224	9,229
Air transport services	5,549	7,383	18,756	39,137	45,188
Portfolio management services		-	4,962	9,157	23,310
Other services	17,566	61,436	55,613	22,071	15,683
Total	**269,462**	**325,387**	**3,906,207**	**740,100**	**690,511**

32. COST OF GOODS SOLD

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Beginning balance of oil products	(4,218,260)	(3,778,519)	(3,778,519)	(2,990,517)	(3,023,987)
Provision for decline in value of oil products (Note 10)	167,270	92,854	92,854	76,542	225,457
Sub-total	(4,050,990)	(3,685,665)	(3,685,665)	(2,913,975)	(2,798,530)
Production costs:					
- Direct materials	(4,118,384)	(5,034,811)	(20,349,186)	(15,368,304)	(12,946,694)
- Supporting materials	(297,191)	(252,808)	(1,151,033)	(879,291)	(619,075)
- Rent	(167,108)	(47,881)	(286,481)	(717,475)	(721,033)
- Depreciation (Note 13)	(125,827)	(136,462)	(566,412)	(551,911)	(501,823)
- Salaries, wages, and other employee benefits	(86,760)	(138,242)	(452,184)	(503,547)	(418,830)
- Freight and transportation	(32,035)	(26,064)	(124,215)	(112,534)	(27,754)
- Custom and duty	(26,997)	(32,953)	(152,255)	(138,148)	(83,934)
- Utilities, infrastructure and fuel	(21,690)	(115,853)	(484,322)	(441,655)	(373,478)
- Materials and equipment	(13,979)	(16,574)	(84,460)	(98,863)	(118,591)
- Maintenance and repairs	(9,673)	(14,882)	(115,899)	(114,228)	(97,794)
- Business travel	(6,088)	(4,529)	(17,109)	(15,569)	(13,878)
- Professional services	(2,250)	(16,105)	(124,109)	(82,225)	(87,689)
- Others	(9,184)	(15,362)	(99,311)	(71,035)	(65,277)
Sub-total	(4,917,166)	(5,852,526)	(24,006,976)	(19,094,785)	(16,075,850)
Purchases of oil products and others:					
- Imports of other oil products	(1,952,760)	(2,046,815)	(9,230,605)	(7,515,863)	(3,676,290)
- Imports of premium gasoline	(1,028,003)	(825,584)	(4,433,062)	(3,811,785)	(3,735,652)
- Domestic purchases of other oil products	(756,652)	(610,506)	(2,782,989)	(2,340,875)	(2,037,140)
- Purchases of geothermal energy	(309,295)	(320,557)	(1,313,799)	(330,505)	(322,251)
- Imports of ADO	(114,457)	(209,163)	(1,385,810)	(853,533)	(449,225)
Sub-total	(4,161,167)	(4,012,625)	(19,146,265)	(14,852,561)	(10,220,558)
Ending balance of oil products	4,222,598	4,049,925	4,218,260	3,778,519	2,990,517
Provision for decline in value of oil products (Note 10)	(106,421)	(131,127)	(167,270)	(92,854)	(76,542)
Sub-total	4,116,177	3,918,798	4,050,990	3,685,665	2,913,975
Total	**(9,013,146)**	**(9,632,018)**	**(42,787,916)**	**(33,175,656)**	**(26,180,963)**

33. UPSTREAM PRODUCTION AND LIFTING COSTS

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Depreciation, depletion and amortization (Note 14)	(484,736)	(465,121)	(1,741,040)	(1,578,988)	(1,568,663)
Contracts	(203,561)	(270,369)	(734,342)	(373,194)	(353,161)
Salaries, wages and other employee benefits	(136,948)	(123,169)	(618,458)	(419,526)	(439,160)
Materials	(106,535)	(74,689)	(267,437)	(287,612)	(222,310)
Technical Assistance Contracts ("TAC")	(64,279)	(139,443)	(335,532)	(136,609)	(283,400)
Amortization of investment in oil & gas block	(25,536)	(30,875)	(144,472)	(116,441)	(114,476)
Others	(139,309)	(120,397)	(545,235)	(508,837)	(288,830)
Total	**(1,160,904)**	**(1,224,063)**	**(4,386,516)**	**(3,421,207)**	**(3,270,000)**

34. EXPLORATION COSTS

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Seismic, geological and geophysical	(14,720)	(36,967)	(89,680)	(40,000)	(37,826)
Dry hole	-	(13,509)	(112,476)	(74,744)	(43,256)
Others	(11,030)	(13,363)	(65,524)	(50,612)	(28,114)
Total	**(25,750)**	**(63,839)**	**(267,680)**	**(165,356)**	**(109,196)**

35. EXPENSES FROM OTHER OPERATING ACTIVITIES

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Cost of services	(283,299)	(214,860)	(917,123)	(561,688)	(491,304)
Salaries, wages and other employee benefits	(48,229)	(39,362)	(173,585)	(148,022)	(119,522)
Depreciation (Note 13)	(23,523)	(22,086)	(88,405)	(84,636)	(77,454)
Insurance claims	(22,380)	(23,777)	(92,864)	(68,616)	(15,212)
Total	**(377,431)**	**(300,085)**	**(1,271,977)**	**(862,962)**	**(703,492)**

36. SELLING AND MARKETING EXPENSES

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Freight and transportation	(167,083)	(69,507)	(453,664)	(519,929)	(419,518)
Depreciation (Note 13)	(78,998)	(80,223)	(328,695)	(362,241)	(313,688)
Salaries, wages, and other employee benefits	(52,932)	(70,168)	(263,020)	(222,447)	(185,476)
LPG filling fee	(34,170)	(17,476)	(113,971)	(132,647)	(98,384)
Professional services	(23,566)	(10,365)	(96,851)	(53,660)	(58,428)
Taxes, retributions and penalties	(18,814)	(9,725)	(89,179)	(46,201)	(48,714)
Maintenance and repairs	(16,818)	(8,535)	(84,776)	(66,757)	(78,172)
Rental	(13,075)	(3,900)	(26,210)	(44,981)	(20,950)
Travel	(5,777)	(4,258)	(15,331)	(12,483)	(10,636)
Advertising and promotions	(5,731)	(2,032)	(24,151)	(25,102)	(16,292)
Utilities, infrastructure and fuel	(4,331)	(4,601)	(21,092)	(8,339)	(11,359)
Materials and equipment	(4,005)	(4,372)	(33,441)	(45,992)	(24,930)
Others	(20,653)	(9,071)	(92,450)	(49,423)	(53,019)
Total	**(445,953)**	**(294,233)**	**(1,642,831)**	**(1,590,202)**	**(1,339,566)**

37. GENERAL AND ADMINISTRATIVE EXPENSES

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Salaries, wages and other employee benefits	(198,668)	(97,323)	(649,669)	(825,414)	(707,655)
Taxes, retributions and penalties	(99,112)	(88,763)	(295,439)	(222,737)	(195,558)
Depreciation, depletion and amortization (Notes 12, 13 and 14)	(19,374)	(15,798)	(107,538)	(109,792)	(112,136)
Materials and equipment	(17,879)	(10,637)	(36,022)	(52,663)	(49,491)
Professional services	(7,729)	(31,381)	(41,828)	(113,979)	(137,567)
Maintenance and repairs	(7,326)	(5,458)	(24,825)	(38,009)	(34,637)
Business travel	(5,864)	(4,684)	(23,252)	(26,136)	(20,719)
Training, education and recruitment	(4,282)	(6,083)	(29,828)	(22,570)	(20,271)
Rental	(2,521)	(12,985)	(31,177)	(19,906)	(54,914)
Others	(32,038)	(8,123)	(90,333)	(167,728)	(176,342)
Total	**(394,793)**	**(281,235)**	**(1,329,911)**	**(1,598,934)**	**(1,509,290)**

38. FINANCE INCOME AND COSTS

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Finance income:					
Time deposits	67,858	30,301	161,818	162,988	219,679
Due from the Government (Note 9a)	56,861	-	-	-	-
Current accounts	12,158	13,202	39,958	38,779	30,654
Other investments	8,995	4,543	54,797	25,277	32,266
Other	-	-	-	6,030	54,035
Total	**145,872**	**48,046**	**256,573**	**233,074**	**336,634**
Finance Costs:					
Bonds	(108,837)	(85,273)	(351,914)	(352,622)	(334,214)
Short-term loans	(32,614)	(2,867)	(56,499)	(8,465)	(13,900)
Long-term loans	(28,425)	(46,606)	(172,586)	(202,974)	(183,171)
Accretion expense (Note 23)	(21,507)	(21,474)	(87,035)	(51,498)	(82,270)
Finance leases	(8,047)	(10,309)	(30,309)	(58,323)	(22,162)
Others	(42,029)	(37,831)	(136,895)	(143,829)	(134,801)
Total	**(241,459)**	**(204,360)**	**(835,238)**	**(817,711)**	**(770,518)**

39. OTHER INCOME (EXPENSES)

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Income from contract and material penalties and claims	11,513	63,293	91,101	41,058	91,775
Adjustment of fair value of other investment (Note 11)	4,918	44,632	52,843	(15,862)	27,328
Rental	3,007	8,304	35,325	34,167	13,730
Recovery (provision) for impairment of receivables	2,350	30,441	108,757	(49,826)	(40,129)
Increase (decrease) in value of investment in oil and gas blocks (Note 12a)	(76,354)	34,691	(154,773)	(83,270)	114,290
Provision for impairment of oil and gas assets (Note 14)	(46,504)	4,971	(218,189)	(191,353)	(186,616)
Interest tax income restitution	-	-	-	99,577	-
Tax penalties under payment tax assesment letter (“SKPKB”) and tax billed (“STP”) (Note 40a)	-	-	(36,622)	-	-
Provision for impairment of goodwill (Note 15d)	-	-	-	(6,890)	(136,264)
Provision for tax dispute (Note 40g)	-	-	-	(621,148)	(733,074)
Tax refund	-	-	-	121,676	
Impairment of advance payment	-	-	-	-	(34,386)
Reversal (impairment) of fixed assets (Note 13)	-	-	2,719	(7,364)	(7,151)
Final income tax asset revaluation (Note 40h)	-	-	-	(129,610)	-
Written off of oil and gas properties	-	-	-	(68,546)	-
Joint operation (“JO”) operation	-	-	-	-	17,642
Others - net (each below US$5,000)	2,400	(6,405)	38,014	46,809	(5,009)
Total	**(98,670)**	**179,927**	**(80,825)**	**(830,582)**	**(877,864)**

40. TAXATION

a. Prepaid taxes

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Corporate Income Tax (“CIT”)				
The Company:				
Overpayment of corporate income tax:				
- 2019	103,219	-	-	-
- 2017	14,520	14,520	164,266	-
- 2015	-	-	-	329,143
- 2014	-	-	-	458,370
- 2013	-	-	-	122,365
- 2012	-	-	-	9,713
- 2011	-	-	-	5,066
- 2005	-	-	-	82,014
Sub-total	117,739	14,520	164,266	1,006,671
Subsidiaries:				
Corporate income tax and dividend	490,161	458,483	330,676	371,965
Sub-total CIT - Consolidated	**607,900**	**473,003**	**494,942**	**1,378,636**

40. TAXATION (continued)

a. Prepaid taxes (continued)

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Value Added Tax ("VAT")				
The Company:				
- 2018	76,615	386,989	-	-
- 2017	-	-	418,255	-
- 2016	84,290	84,290	-	-
- 2012	-	-	-	82,353
- 2009	-	-	-	18,750
- 2007	-	-	-	124,624
Sub-total	160,905	471,279	418,255	225,727
Subsidiaries:				
VAT reimbursable	282,161	290,872	313,468	404,523
VAT	304,088	386,737	396,890	214,618
Sub-total	586,249	677,609	710,358	619,141
Sub-total VAT - Consolidated	**747,154**	**1,148,888**	**1,128,613**	**844,868**
Other taxes	**18,994**	**18,994**	**-**	**127,080**
Total prepaid tax	**1,374,048**	**1,640,885**	**1,623,555**	**2,350,584**
Provision	-	-	-	(313,196)
Total	**1,374,048**	**1,640,885**	**1,623,555**	**2,037,388**
Current portion	(499,661)	(820,598)	(794,255)	(567,621)
Non-current portion	**874,387**	**820,287**	**829,300**	**1,469,767**

Details of VAT reimbursable are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
VAT reimbursable by SKK Migas:				
- PT Pertamina EP	78,704	84,264	73,348	130,604
- PGN and its subsdiaries	62,849	69,014	75,356	92,585
- PT Pertamina EP Cepu	30,735	31,194	43,160	55,253
- PHE and its subsdiaries	3,436	3,643	26,638	40,817
Sub-total	175,724	188,115	218,502	319,259
VAT reimbursable by the Directorate General of Budgeting and Finance Stability:				
PT Pertamina Geothermal Energy	106,437	102,757	94,966	85,264
Total	**282,161**	**290,872**	**313,468**	**404,523**

On December 27, 2018, the Company received SKPKB and STP for fiscal year 2016 amounting to Rp3.23 trillion (equivalent to US$222,250). The SKPKB consists of SKPKB of Corporate Income Tax amounting to Rp565.95 billion (equivalent to US$39,031), SKPKB of withholding income tax amounting to Rp1.38 trillion (equivalent to US$94,851) and SKPKB of VAT amounting to Rp295 billion (equivalent to US$20,260). STP consists of tax bills on VAT and penalties amounting to Rp590.93 billion (equivalent to US$40,578) and Rp400.93 billion (equivalent to US$27,530) (Note 50c), respectively.

From the overall value of the SKPKB and STP, the Company charged Rp533.32 billion (equivalent to US$36,622) in the 2018 income statement (Note 39), Rp1.5 trillion (equivalent to US$103,283) was recorded as prepaid tax, and Rp565.95 billion (equivalent to US$39,030) was recorded as prior year adjustment of corporate income tax, while the remaining value of amounting to Rp630.78 billion (equivalent to US$43,315) has not been paid.

On January 25, 2019, the Company has filed an objection for the SKPKB PPh 22, PPh 23, PPh 4 (2), PPh 15, SKPKB and STP of VAT.

40. TAXATION (continued)

a. Prepaid taxes (continued)

On March 21, 2019, the Company obtained from Directorate General of Taxes ("DGT") decisions No. KEP-00244/NKEB/WPJ.19/2019 until KEP-00255/NKEB/WPJ.19/2019 regarding the write-off STP VAT for fiscal year 2016 amounted Rp590.93 billion (equivalent to US$40,578). As of March 31, 2019, the amount was still recorded as prepaid tax due to the Company plan to net off with next period tax payment.

On November 7, 2018, the Company received a letter of tax refund for overpayment of CIT fiscal year 2017 from DGT of Big Three Taxpayers office No.80367/051-00367-2018 for tax refund amounting to Rp2.26 trillion by calculating taxes payable compensation amounting to Rp159 million, so it was paid amounting to Rp2.26 trillion (equivalent to US$154,758).

On February 9, 2018, the Company obtained decision No. Kep-29/WPJ.19/2018 from DGT regarding the Determination of Certain Taxpayers with Specific Criteria, effective from January 1, 2018 to December 31, 2019. Taxpayers that fulfilled all criterias can be granted any tax refund if they had previously overpaid taxes.

On March 21, 2017, the Tax Court partially accepted the Company's tax appeals on SKPKB of VAT for period December 2007. The Company received tax refund for the overpayment of VAT amounting to Rp1,621 million (equivalent to US$121,576) on August 3, 2017.

The increase in VAT payments in 2017 was mainly due to advance payment of VAT for LPG and diesel subsidies, and withholding tax.

On March 3, 2017, the Company received tax refund overpayment letters for overpayment of CIT fiscal years 2014 and 2013 amounting to Rp3,884 million (equivalent to US$296,363) and Rp23 million (equivalent to US$1,754), respectively.

On December 31, 2015, through letter No.860/H00000/2015-S4, the Company submitted a request for revaluation of fixed assets for tax purposes submitted in 2015 to the Regional Office of DGT Large Taxpayers and has paid the final income tax amounting to Rp1.3 trillion (equivalent to US$95,182).

On December 7, 2016, through letter No. 751/H00000/2016-S4, the Company notified DGT that the submission for the tax requirements regarding revaluation will be deferred to 2017. As a consequence, the Company made additional final income tax payment in December 2016 on the revaluation amounting to Rp429,771,563,671 (full amount) (equivalent to US$31,899).

The payment of final income tax amounting to Rp1.3 trillion (equivalent to US$95,182) and the additional payment of final income tax on revaluation amounting to Rp429,771,563,671 (full amount) (equivalent to US$31,899) are presented under prepaid taxes - current portion in the 2016 consolidated statement of financial position.

b. Taxes payable

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Corporate income tax - Company	19,267	19,684	-	214,988
Corporate income tax - Subsidiaries	502,151	447,921	308,803	260,588
Sub-total	521,418	467,605	308,803	475,576
Other taxes:				
- Income taxes - Article 21	51,244	33,909	39,763	41,982
- Income taxes - Article 22	13,789	10,580	6,341	7,907
- Income taxes - Article 23/26	13,055	13,189	11,363	30,196
- Income taxes - Article 15/4(2)	7,087	6,271	7,101	5,477
- Income taxes - Article 24	5	269	1	5
- VAT	98,853	74,542	68,617	58,001
- Fuel taxes	115,770	119,645	117,347	107,985
Sub-total	299,803	258,405	250,533	251,553
Total	**821,221**	**726,010**	**559,336**	**727,129**

40. TAXATION (continued)

c. Income tax expense - net

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Current tax expense	(542,220)	(547,791)	(2,627,443)	(1,699,088)	(2,046,133)
Deferred income tax benefit (expense)	(78,056)	(181,842)	(385,759)	532,264	168,484
Net	**(620,276)**	**(729,633)**	**(3,013,202)**	**(1,166,824)**	**(1,877,649)**

d. Current taxes

Current income tax computation is based on estimated taxable income/(loss). The amounts may be adjusted when annual tax returns are filed with the DGT.

The reconciliation between the consolidated profit before income tax and estimated taxable income is as follows:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Consolidated profit before income tax expense	1,193,633	1,417,400	5,729,596	3,867,228	5,348,883
Add:					
Consolidation eliminations	865,520	804,462	3,610,474	2,247,936	1,950,464
Profit before income tax - Subsidiaries	(1,464,479)	(1,617,504)	(6,610,027)	(3,821,301)	(3,021,213)
Profit before income tax - the Company	594,674	604,358	2,730,043	2,293,863	4,278,134
Temporary differences:					
Provision for incentives and performance bonuses (tantiem)	(95,221)	(118,319)	(6,894)	19,920	82,587
Provision for impairment of financial assets	(2,348)	(48,600)	(139,273)	20,305	59,249
Finance lease assets and liabilities	(1,370)	(2,050)	(7,368)	48,659	11,318
Discount and unamortized debt issuance cost	(22)	1,081	(55)	8,095	6,929
Provision for impairment of non-free and non-clear assets	-	-	-	-	2,589
Accrual for legal costs	227	(220)	14,918	8,087	2,044
Provision for impairment of inventories	(92,544)	35,430	137,248	32,404	(181,202)
Fixed assets depreciation	(8,150)	(58,403)	(112,976)	(2,756)	(44,036)
Receivable fair value adjustment from differences in pricing (Note 2u and 9a)	(105,084)	-	981,331	-	-
Employee benefits liability	15,887	(87,947)	(181,421)	(121,652)	(18,346)
Fixed asset revaluation	-	-	(14,221)	-	-
Others	(6,002)	(87)	7,624	(346)	(346)

40. TAXATION (continued)

d. Current taxes (continued)

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Permanent differences:					
Non-deductible expenses	88,032	514,034	342,456	1,093,884	1,273,304
Post-retirement healthcare benefits	25,891	(34,663)	648	46,334	71,192
Non-depreciable fixed assets	1,294	(99)	5,372	5,201	1,604
Income from subsidiaries and associates	(677,544)	(775,544)	(3,341,620)	(1,997,866)	(1,557,363)
Interest income subjected to final tax	(73,811)	(27,443)	(149,244)	(148,704)	(213,821)
Other income subjected to final tax	(1,823)	(466,804)	1,055,818	(147,399)	(12,565)
Total temporary and permanent differences	(932,588)	(1,069,634)	(1,407,657)	(1,135,834)	(516,863)
Taxable income (loss) - the Company	**(337,914)**	**(465,276)**	**1,322,386**	**1,158,029**	**3,761,271**
Current income tax - the Company	-	-	330,597	289,507	940,318
Under provision of 2005 corporate income tax - the Company	-	-	42,403	-	-
Current income tax - Subsidiaries	542,220	547,791	2,254,443	1,409,581	1,105,815
Consolidated current income tax	**542,220**	**547,791**	**2,627,443**	**1,699,088**	**2,046,133**

The reconciliation between the Group's income tax expense and the theoretical tax amount on the Group's consolidated profit before income tax is as follows:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Profit before income tax - Consolidated	1,193,633	1,417,400	5,729,596	3,867,228	5,348,883
Tax calculated at weighted average statutory tax rates	839,304	598,536	2,301,890	1,828,634	2,034,422
Non-deductible expenses	85,867	420,319	375,007	492,336	428,749
Post-retirement healthcare benefits	6,473	(8,666)	162	11,583	17,798
Non-depreciable fixed assets	329	(18)	1,368	(8,856)	429
Income from subsidiaries and associates	(205,251)	(205,638)	(868,954)	(553,989)	(430,719)
Income subjected to final tax	(169,853)	(185,072)	1,198,784	(35,280)	(129,449)
Interest income subjected to final tax	(21,072)	(6,147)	(37,458)	(34,943)	(43,581)
Fixed assets revaluation	-	-	-	(532,661)	-
Prior year adjustments	-	-	42,403	-	-
Unrecognized tax loss	84,479	116,319	-	-	-
Consolidated corporate income tax expense	**620,276**	**729,633**	**3,013,202**	**1,166,824**	**1,877,649**

The theoretical amount of income tax expense is calculated using the weighted average tax rate applicable to entities consolidated to the Group. The weighted average tax rate was 52%,51%,53%,30% and 35% for the three-month periods ended March 31, 2019 and 2018, and the years ended December 31, 2018, 2017, and 2016, respectively.

40. TAXATION (continued)

e. Deferred tax

	March 31, 2019 (unaudited)						
	January 1, 2019	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	March 31, 2019
Deferred tax assets							
Employee benefits	247,522	-	11	(3,549)	(61)	14,017	257,940
Provision for impairment of financial assets	79,477	-	-	65	-	(595)	78,947
Provision for decommissioning and site restoration	122,236	-	6	(98,265)	-	10,869	34,846
Provision for incentives and performance bonuses (tantiem)	62,096	-	-	17	-	(21,231)	40,882
Unrealized profits from transaction at consolidation level	75,694	-	-	-	-	24,237	99,931
Fixed assets	586,578	-	-	40,997	-	(11,882)	615,693
Provision for impairment of inventories	70,367	-	-	9	-	(23,556)	46,820
Provision for impairment of non-free and non-clear assets	27,589	-	-	-	-	(1)	27,588
Tax losses carry-forward	2,071	-	(433)	(1,127)	-	5,038	5,549
Deferred revenues	276	-	-	-	-	1,260	1,536
Accrual for legal cost	7,369	-	-	-	-	57	7,426
Oil and gas properties	(72,763)	-	-	-	-	72,788	25
Finance lease assets and liabilities	(12,996)	-	-	1	-	(95)	(13,090)
Discount and unamortized debt issuance cost	(5,951)	-	-	-	-	(6)	(5,957)
Receivable fair value adjustment from Disparity of Selling Price (Notes 2u and 9a)	245,333	-	-	-	-	(26,271)	219,062
Others	6,968	-	181	(6,074)	-	10,480	11,555
Sub-total consolidated deferred tax assets - net	**1,441,866**	**-**	**(235)**	**(67,926)**	**(61)**	**55,109**	**1,428,753**
Deferred tax liabilities							
Provision for decommissioning and site restoration	365,066	-	-	-	-	(63,055)	302,011
Finance lease assets	29,905	-	-	-	-	7,775	37,680
Deferred revenues	8,068	-	-	-	-	(3,244)	4,824
Employee benefits	16,657	-	-	-	-	(2,855)	13,802
Provision for impairment	2,008	-	-	-	-	(43)	1,965
Oil and gas properties	(3,070,616)	-	-	86,106	-	(27,632)	(3,012,142)
Excess of fair value over net book value	(12,598)	-	-	-	-	1,583	(11,015)
Fixed assets	(201,891)	-	-	(57)	-	(21,188)	(223,136)
Unrealized profits from transaction at consolidation level	(342,856)	-	-	-	-	8,204	(334,652)
Others	(101,149)	-	-	(328)	-	(32,710)	(134,187)
Sub-total consolidated deferred tax liabilities - net	**(3,307,406)**	**-**	**-**	**85,721**	**-**	**(133,165)**	**(3,354,850)**
Total	**(1,865,540)**	**-**	**(235)**	**17,795**	**(61)**	**(78,056)**	**(1,926,097)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2018						
	January 1, 2018	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2018
Deferred tax assets							
Employee benefits	314,471	-	516	5,143	(1,302)	(71,306)	247,522
Provision for impairment of financial assets	121,406	-	-	(367)	-	(41,562)	79,477
Provision for decommissioning and site restoration	136,394	-	591	-	-	(14,749)	122,236
Provision for incentives and performance bonuses (tantiem)	83,513	-	-	(43)	-	(21,374)	62,096
Unrealized profits from transaction at consolidation level	64,825	-	-	-	-	10,869	75,694
Fixed assets	518,336	-	-	(3,486)	133	71,595	586,578
Provision for impairment of inventories	37,156	-	-	(46)	-	33,257	70,367
Provision for impairment of non-free and non-clear assets	27,588	-	-	1	-	-	27,589
Tax losses carry-forward	13,764	-	1,567	(27)	-	(13,233)	2,071
Deferred revenues	7,590	-	-	-	-	(7,314)	276
Accrual for legal cost	3,640	-	-	-	-	3,729	7,369
Oil and gas properties	(5,002)	-	(3,382)	-	-	(64,379)	(72,763)
Finance lease assets and liabilities	(11,205)	-	-	2	-	(1,793)	(12,996)
Discount and unamortized debt issuance cost	(5,937)	-	-	-	-	(14)	(5,951)
Receivable fair value adjustment from Disparity of Selling Price (Notes 2u and 9a)	-	-	-	-	-	245,333	245,333
Others	64,541	-	(2,439)	(298)	-	(54,836)	6,968
Sub-total consolidated deferred tax assets - net	**1,371,080**	**-**	**(3,147)**	**879**	**(1,169)**	**74,223**	**1,441,866**
Deferred tax liabilities							
Provision for decommissioning and site restoration	371,738	-	-	-	-	(6,672)	365,066
Finance lease assets	29,013	-	-	-	-	892	29,905
Deferred revenues	10,750	-	-	-	-	(2,682)	8,068
Employee benefits	8,549	-	-	-	(395)	8,503	16,657
Provision for impairment	1,081	-	-	-	-	927	2,008
Oil and gas properties	(2,801,228)	-	-	-	-	(269,388)	(3,070,616)
Excess of fair value over net book value	(14,114)	-	-	-	-	1,516	(12,598)
Fixed assets	(351,100)	-	-	174	-	149,035	(201,891)
Unrealized profits from transaction at consolidation level	(377,158)	-	-	-	-	34,302	(342,856)
Others	274,317	-	-	949	-	(376,415)	(101,149)
Sub-total consolidated deferred tax liabilities - net	**(2,848,152)**	**-**	**-**	**1,123**	**(395)**	**(459,982)**	**(3,307,406)**
Total	**(1,477,072)**	**-**	**(3,147)**	**2,002**	**(1,564)**	**(385,759)**	**(1,865,540)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2017						
	January 1, 2017	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2017
Deferred tax assets							
Employee benefits	302,651	-	321	3,365	40,486	(32,352)	314,471
Provision for impairment of financial assets	114,611	-	864	(98)	-	6,029	121,406
Provision for decommissioning and site restoration	123,449	-	-	-	-	12,945	136,394
Provision for incentives and performance bonuses (tantiem)	72,084	-	-	102	-	11,327	83,513
Unrealized profits from transaction at consolidation level	48,756	-	-	-	-	16,069	64,825
Fixed assets	(24,717)	-	2,612	(17)	-	540,458	518,336
Provision for impairment of inventories	29,194	-	-	(8)	-	7,970	37,156
Provision for impairment of non-free and non-clear assets	27,588	-	-	-	-	-	27,588
Tax losses carry-forward	41,240	-	-	-	-	(27,476)	13,764
Deferred revenues	12,100	-	-	140	-	(4,650)	7,590
Accrual for legal cost	1,618	-	-	-	-	2,022	3,640
Oil and gas properties	(37,375)	-	-	-	-	32,373	(5,002)
Finance lease assets and liabilities	(23,333)	-	-	(1)	-	12,129	(11,205)
Discount and unamortized debt issuance cost	(7,962)	-	-	-	-	2,025	(5,937)
Others	71,559	-	666	(36)	-	(7,648)	64,541
Sub-total consolidated deferred tax assets - net	**751,463**	**-**	**4,463**	**3,447**	**40,486**	**571,221**	**1,371,080**
Deferred tax liabilities							
Provision for decommissioning and site restoration	367,350	(1,058)	-	-	-	5,446	371,738
Finance lease assets	30,670	-	-	-	-	(1,657)	29,013
Deferred revenues	22,404	-	-	-	-	(11,654)	10,750
Employee benefits	7,353	-	-	-	180	1,016	8,549
Provision for impairment	1,085	696	-	-	-	(700)	1,081
Oil and gas properties	(2,437,710)	(276,196)	-	-	-	(87.322)	(2,801,228)
Excess of fair value over net book value	(30,845)	2,352	-	-	-	14,379	(14,114)
Fixed assets	(242,785)	(8,362)	-	575	-	(100,528)	(351,100)
Unrealized profits from transaction at consolidation level	(410,531)	-	-	-	-	33,373	(377,158)
Others	164,492	48	-	1,087	-	108,690	274,317
Sub-total consolidated deferred tax liabilities - net	**(2,528,517)**	**(282,520)**	**-**	**1,662**	**180**	**(38,957)**	**(2,848,152)**
Total	**(1,777,054)**	**(282,520)**	**4,463**	**5,109**	**40,666**	**532,264**	**(1,477,072)**

40. TAXATION (continued)

e. Deferred tax (continued)

	December 31, 2016						
	January 1, 2016	Additions from business combinations	Charged to equity	Translation adjustment	Charged to OCI	Charged to profit or loss	December 31, 2016
Deferred tax assets							
Employee benefits	289,390	-	(4,208)	2,331	16,029	(891)	302,651
Provision for impairment of financial assets	99,317	-	(115)	97	-	15,312	114,611
Provision for decommissioning and site restoration	74,989	-	-	-	-	48,460	123,449
Provision for incentives and performance bonuses (tantiem)	51,630	-	-	(1,680)	-	22,134	72,084
Unrealized profits from transaction at consolidation level	37,732	-	-	-	-	11,024	48,756
Fixed assets	883	-	(1,124)	52	-	(24,528)	(24,717)
Provision for impairment of inventories	72,099	-	-	17	-	(42,922)	29,194
Provision for impairment of non-free and non-clear assets	26,941	-	-	-	-	647	27,588
Tax losses carry-forward	43,114	-	-	-	-	(1,874)	41,240
Deferred revenues	11,456	-	(1,033)	-	-	1,677	12,100
Accrual for legal cost	1,107	-	-	-	-	511	1,618
Oil and gas properties	(39,211)	-	-	-	-	1,836	(37,375)
Finance lease assets and liabilities	(26,204)	-	-	-	-	2,871	(23,333)
Discount and unamortized debt issuance cost	(9,717)	-	-	-	-	1,755	(7,962)
Others	72,066	-	543	51	-	(1,101)	71,559
Sub-total consolidated deferred tax assets - net	**705,592**	**-**	**(5,937)**	**868**	**16,029**	**34,911**	**751,463**
Deferred tax liabilities							
Provision for decommissioning and site restoration	349,814	-	-	-	-	17,536	367,350
Finance lease assets	27,751	-	-	-	-	2,919	30,670
Deferred revenues	29,449	-	-	-	-	(7,045)	22,404
Employee benefits	10,724	-	-	-	(839)	(2,532)	7,353
Provision for impairment	5,888	-	-	-	-	(4,803)	1,085
Oil and gas properties	(2,544,971)	-	-	-	-	107,261	(2,437,710)
Excess of fair value over net book value	(33,130)	-	-	-	-	2,285	(30,845)
Fixed assets	(226,707)	-	-	-	-	(16,078)	(242,785)
Unrealized profits from transaction at consolidation level	(429,915)	-	-	-	-	19,384	(410,531)
Others	162,407	(10,396)	-	(2,165)	-	14,646	164,492
Sub-total consolidated deferred tax liabilities - net	**(2,648,690)**	**(10,396)**	**-**	**(2,165)**	**(839)**	**133,573**	**(2,528,517)**
Total	**(1,943,098)**	**(10,396)**	**(5,937)**	**(1,297)**	**15,190**	**168,484**	**(1,777,054)**

Deferred tax assets and liabilities as of March 31, 2019, and December 31, 2018, 2017, and 2016 have been calculated taking into account the applicable tax rates for each respective period.

The Group's management is of the opinion that the above deferred tax assets can be fully recovered through future taxable income.

40. TAXATION (continued)

f. Administration

The Indonesian prevailing Tax Law requires each Company in the Group to submit individual tax returns on the basis of self assessment. Under the prevailing regulations, DGT may assess or amend tax within certain periods. For the fiscal year of 2007 and backward, this amendment period is within ten years from the time the tax due, but not later than 2013, while for the fiscal year of 2008 and onwards, the period is within five years from the time the tax due.

g. Tax amnesty

The Company participated in Tax Amnesty Program on March 31, 2017 and received the certificate of Tax Amnesty No. KET-369/PP/WPJ.19/2017 on April 6, 2017. As a result the Company withdrew, by law, all processes of Objections, Appeals, and Judicial reviews for the fiscal year until 2015.

The results of the tax amnesty program are as follows:
a. The Company's remaining amount of 2014 fiscal loss amounting to US$75,362 will not be compensated.
b. Tax dispute which was previously recognized in prepaid tax - non-current portion amounting to US$621,148 (net of provision which has been recorded) (Note 39), were expensed.

PT Pertamina Lubricants participated in Tax Amnesty Program on March 31, 2017 and received the certificate of Tax Amnesty on April 5, 2017. As a result, PT Pertamina Lubricants withdrew, by law, all processes of Objections, Appeals, and Judicial reviews for the fiscal year until 2015.

As consequences of the tax amnesty program discussed above, PT Pertamina Lubricants has written-off its input VAT amounting to Rp210,301 millions (equivalent to US$15,418).

h. Fixed asset revaluation fo tax purposes

The Company submitted a request to revalue certain refineries assets for tax purposes on December 28, 2016.

On July 10, 2017 the Company received approval for the revaluation of refineries as refered to the decision of the Director General of Taxes No. KEP-104/WPJ.19/2017. The consequences of the approval are as follows:
a. Prepaid tax of final income tax amounting to US$129,610 was recognized as expense (Note 39).
b. Recognized deferred tax assets amounting to US$532,660.

41. RELATED PARTY BALANCES AND TRANSACTIONS

Significant related party accounts are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Cash and cash equivalents (Note 6)	7,609,211	8,416,251	6,065,489	6,465,644
Restricted cash (Note 7)	86,100	86,230	88,896	114,855
Trade receivables - related parties (Note 41a)	1,537,251	1,297,651	1,095,016	1,422,268
Due from the Government (Note 9)	5,566,906	4,758,409	2,155,739	1,792,457
Other receivables - related parites (Note 41b)	165,179	149,178	255,054	242,839
Restricted cash - non-current (Note 15a)	908,502	876,168	834,874	635,747
Advance dividend payment (Note 27b)	-	-	-	37,120
Total dividend	**15,873,149**	**15,583,887**	**10,495,068**	**10,710,930**
As a percentage of total assets	**24%**	**24%**	**18%**	**20%**
Short-term loans (Note 16)	2,249,537	3,164,724	355,518	47,509
Trade payables - related parties (Note 41c)	53,561	78,781	49,277	118,540
Due to the Government (Note 18)	2,516,044	2,002,825	1,831,245	1,685,118
Long-term liabilities (Note 20)	178,540	179,361	174,638	211,074
Other payables - related parties (Note 41d)	38,772	54,011	56,625	50,947
Total	**5,036,454**	**5,479,702**	**2,467,303**	**2,113,188**
As a percentage of total liabilities	**14%**	**16%**	**8%**	**7%**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

a. Trade receivables

Trade receivables - related parties result from domestic sales of crude oil, natural gas and geothermal energy and the export of oil products.

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Trade receivables - related parties	1,570,406	1,330,381	1,141,863	1,528,092
Provision for impairment	(33,155)	(32,730)	(46,847)	(105,824)
Net	**1,537,251**	**1,297,651**	**1,095,016**	**1,422,268**

Trade receivables based on customers are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Indonesian Armed Forces ("TNI")/ Ministry of Defence (Note 48b.ii)	433,760	318,142	258,566	644,950
PT Garuda Indonesia (Persero) Tbk	386,005	226,166	106,801	93,939
PLN and its subsidiaries	366,900	381,559	385,419	493,043
PT Patra SK	42,985	40,013	40,117	35,754
PT Pupuk Indonesia (Persero)	23,022	25,412	43,667	33,105
Polisi Republik Indonesia ("Polri")	12,715	508	-	253
PT Merpati Nusantara Airlines (Persero)	11,681	11,499	12,254	12,352
PT Aneka Tambang	7,374	14,226	-	-
PT Pembangkit Jawa-Bali	398	17,484	1,069	5,302
PPT Energy Trading Co.,Ltd.	22	22	47,275	-
PT Donggi – Senoro LNG	-	28,828	14,789	12,031
Others	285,544	266,522	231,906	197,363
	1,570,406	1,330,381	1,141,863	1,528,092
Provision for impairment	(33,155)	(32,730)	(46,847)	(105,824)
Total	**1,537,251**	**1,297,651**	**1,095,016**	**1,422,268**

Movements in the provision for impairment of trade receivables from related parties are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Beginning balance	(32,730)	(46,847)	(105,824)	(47,550)
Reversal of provision for impairment for recovered receivables - net	47	18,734	92,757	14,006
Impairment during the period/year	(89)	(7,606)	(32,854)	(73,604)
Foreign exchange	(383)	2,989	(926)	1,324
Ending balance	**(33,155)**	**(32,730)**	**(46,847)**	**(105,824)**

Management believes that the provision for impairment is adequate to cover possible losses that may arise from the uncollectible trade receivables from related parties.

Details of trade receivables by currencies are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Rupiah	1,079,530	870,672	610,347	1,080,200
US dollar	490,463	459,641	531,449	447,828
Others	413	68	67	64
Total	**1,570,406**	**1,330,381**	**1,141,863**	**1,528,092**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

a. Trade receivables (continued)

Receivable from fuel and lubricant distribution to the Indonesian Armed Forces/Ministry of Defence

The fuel and lubricant distribution to the Indonesian Armed Forces/Ministry of Defence is based on the planned needs of the Indonesian Armed Forces/Ministry of Defence and is capped by the State Budget for Fuels and Lubricants ("BMP") as one of the expenditure items of the Indonesian Armed Forces/Ministry of Defence, the details are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	318,142	258,566	644,950	487,515
Distribution of fuel and lubricant	110,331	479,959	383,307	344,097
Collections from BMP distribution	-	(403,723)	(764,355)	(199,693)
Foreign exchange	5,287	(16,660)	(5,336)	13,031
Net	**433,760**	**318,142**	**258,566**	**644,950**

At March 31, 2019, and December 31, 2018, 2017, and 2016, management has recognized impairment in the amount of US$13,208, and US$12,992, US$10,409 and US$85,136, respectively.

Receivable from fuel distribution to PLN/Perusahaan Listrik Negara

The Company distributes diesel fuel and industrial fuel oil to PLN for their power plant in all regions across Indonesia. In 2017, the Company has made collections from PLN based on the price agreed by the Boards of Directors of the Company and PLN on May 22, 2018.

Should there be difference between the provisional and the final agreed formulation prices, the adjustment will be recorded in the period when the final formulation prices agreement is completed.

b. Other receivables

Other receivables by customers are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
PT Donggi-Senoro LNG	117,083	115,500	109,458	105,286
PT Jawa Satu Power	-	-	96,000	-
PT Perta Daya Gas	-	-	34,152	-
PT Merpati Nusantara Airlines (Persero)	18,481	18,190	19,472	19,550
Others (each below US$10,000)	93,431	100,011	97,181	225,218
Sub-total	228,995	233,701	356,263	350,054
Provision for impairment	(19,918)	(19,616)	(20,860)	(20,983)
Sub-total	209,077	214,085	335,403	329,071
Less: current portion	**(165,179)**	**(149,178)**	**(255,054)**	**(242,839)**
Non-current portion (Note 15)	**43,898**	**64,907**	**80,349**	**86,232**

Movements in the provision for impairment of other receivables from related parties are as follows:

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Beginning balance	(19,616)	(20,860)	(20,983)	(20,491)
Reversal of impairment on the recovered receivables	-	699	127	1
Impairment during the period/year	-	(705)	(162)	(1)
Foreign exchange difference	(302)	1,250	158	(492)
Ending balance	**(19,918)**	**(19,616)**	**(20,860)**	**(20,983)**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

b. Other receivables (continued)

Management believes that the provision for impairment is adequate to cover possible losses that may arise from the uncollectible other receivables from related parties.

Receivables from PT Donggi-Senoro LNG

The receivables from PT Donggi-Senoro LNG as of March 31, 2019 and December 31, 2018, 2017, and 2016 amounted to US$117,083 and US$115,500, US$109,458 and US$105,286 are intended for the construction of a LNG production facility with a capacity of 2 million tonnes per year. PT Donggi Senoro LNG is owned by PHE (29%), Sulawesi LNG Development Limited (59.9%) and PT Medco LNG Indonesia (11.1%). This project, which was planned to be finalised in 4 years, is funded by 40% from equity and 60% from loan.

The interest rate on the loan is one month US Dollar LIBOR plus 3.75% per annum and interest is due every three months after the loan drawdowns. In 2018 and 2017, accrued interest was added to the loan since the LNG production facility is still under construction. Interest income for the three-month periods ended March 31, 2019, and for the years ended December 31, 2018, 2017, and 2016 are US$1,862, and US$7,110, US$4,908 and US$4,050 respectively.

PT Merpati Nusantara Airlines (Persero) (“MNA”)

On October 27, 2009, MNA requested to restructure its payable. An agreement was made on October 17, 2011 through a meeting at the Ministry of State-Owned Enterprises. As of March 31, 2019, and December 31, 2018, 2017, and 2016, the provision for impairment for this receivable amounted to US$18,481, and US$18,190, US$19,472 and US$19,550 respectively.

c. Trade payables

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
PT Seamless Pipe Indonesia Jaya	2,674	739	-	-
PT Asuransi Jasa Indonesia (Persero)	1,575	6,279	-	-
PT Rekayasa Industri	8	8	200	36,873
PT Wijaya Karya (Persero) Tbk	-	-	-	16,927
Others	49,304	71,755	49,077	64,740
Total	**53,561**	**78,781**	**49,277**	**118,540**

d. Other payables

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
PT PLN (Persero)	292	6,044	31,452	17,144
Others	38,480	47,967	25,173	33,803
Total	**38,772**	**54,011**	**56,625**	**50,947**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

e. Sales and other operating revenues

The Group made sales and other operating revenues to related parties for the three-month periods ended March 31, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016. Sales to related parties represent 18%, 21% and 24%, 18%, 16% of the total sales and other operating revenues for the respective periods/years. The details are as follows:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Domestic sales of crude oil, natural gas, geothermal energy and oil products					
- Government-related entities	944,154	1,082,534	4,872,641	3,961,054	3,505,441
- Shareholder	130,989	138,942	3,553,097	401,299	367,301
- Associates	273	404	1,222	735	5,021
Subsidy reimbursements from the Government					
- Shareholder	1,212,497	1,342,764	5,632,468	3,572,084	2,568,844
Marketing fees					
- Shareholder	2,901	1,782	15,432	25,474	(257,485)
Revenues from other operating activities					
- Government-related entities	18,192	34,077	108,514	128,870	93,319
Total	**2,309,006**	**2,600,503**	**14,183,374**	**8,089,516**	**6,282,441**

f. Cost of goods sold

Purchases from related parties for the three-month periods ended March 31, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016 represent 23%, 24%, 25%, 22% and 19% of the total cost of goods sold, for the respective periods/years. The details are as follows:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Crude oil and gas for shareholder	2,075,882	2,156,959	10,002,633	6,879,687	4,726,374
Oil products:					
Associates	-	77,713	332,752	82,140	180,276
Joint ventures	34,840	40,239	158,260	174,842	132,717
Government-related entities	-	-	-	-	1,238
Total	**2,110,722**	**2,274,911**	**10,493,645**	**7,136,669**	**5,040,605**

41. RELATED PARTY BALANCES AND TRANSACTIONS (continued)

g. Compensation of key management and Board of Commissioners

Key management comprises the Board of Directors and other key management personnel who have significant involvement in the operations of the Company. The compensation paid or payable to key management and Board of Commissioners is shown below:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Salaries and other benefits	2,248	5,951	47,273	52,781	42,469

h. Relationship with related parties

The nature of relationships with the related parties is as follows:

Relationships	Related parties
• Shareholder	The Government of the Republic of Indonesia
• Associates	Pacific Petroleum & Trading Co. Ltd. PT Trans-Pacific Petrochemical Indotama PT Donggi Senoro LNG PT Asuransi Samsung Tugu Seplat Petroleum Development Company Plc.
• Joint ventures	PT Patra SK PT Perta Samtan Gas PT Perta Daya Gas PT Indo Thai Trading PT Elnusa CGGVeritas Seismic Unimar LLC PT Transportasi Gas Indonesia PT Permata Karya Jasa (Perkasa) PT Pertamina Rosneft Pengelolaan dan Petrokimia
• Common key management	Koperasi Karyawan Pertamina Dana Pensiun Pertamina Pertamina Foundation Yayasan Kesehatan Pertamina
• Government-related entities	Indonesian Armed Forces/Police of the Republic of Indonesia Ministry of Finance PT Perusahaan Listrik Negara (Persero) PT Pupuk Indonesia (Persero) PT Krakatau Steel (Persero) Tbk PT Garuda Indonesia (Persero) Tbk PT Merpati Nusantara Airlines (Persero) PT Wijaya Karya (Persero) Tbk PT PAL Indonesia (Persero) PT Bina Bangun Wibawa Mukti PT Rekayasa Industri PT Asuransi Jasa Indonesia (Persero) PT Sarana Multi Infrastruktur (Persero) BNI BNI Syariah BRI Bank Mandiri Bank Mandiri Syariah Indonesian Eximbank State-Owned Enterprises Local Government-Owned Enterprises
• Key Management Personnel	Board of Directors Other key management of the personnel
• Governance Oversight Body	Board of Commissioners

42. SEGMENT INFORMATION

Management has determined the operating segments based on the reports reviewed by the strategic steering committee that are used to make strategic decisions.

Segments are grouped into two principal business activities consisting of Upstream and Downstream, representing the Company's reportable segments as defined in the accounting standards for segment reporting SFAS 5 (Amendment 2014), Operating Segments (Note 2w). Business activities related with Gas and New and Renewable Energy are currently grouped into Other segment because they still have not met quantitative thresholds as a reportable operating segment.

	March 31, 2019 (unaudited)					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	1,671,923	10,004,296	993,968	12,670,187	-	12,670,187
Inter-segment sales	1,350,927	218,862	81,208	1,650,997	(1,650,997)	-
Total segment revenues	3,022,850	10,223,158	1,075,176	14,321,184	(1,650,997)	12,670,187
Segment results**)	1,368,678	(160,405)	165,400	1,373,673	(121,463)	1,252,210
Gain (loss) on foreign exchange - net						119,907
Finance income						145,872
Finance costs						(241,459)
Share in net profit of associates and joint venture						15,773
Other expenses - net						(98,670)
						(58,577)
Profit before income tax						1,193,633
Income tax expense						(620,276)
Profit for the period/year after the effect of merging entity's income adjustment						**573,357**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						519,115
Non-controlling interests						54,242
Other information						
Segment assets	24,830,995	33,448,266	8,471,086	66,750,347	(4,393,771)	62,356,576
Long-term investments	1,932,879	19,664,087	463,006	22,059,972	(19,331,352)	2,728,620
Total assets	26,763,874	53,112,353	8,934,092	88,810,319	(23,725,123)	65,085,196
Total liabilities	11,841,299	24,164,384	2,990,708	38,996,391	(4,033,108)	34,963,283
Depreciation, depletion and amortization expense	468,319	176,693	112,982	757,994	-	757,994
Additions to fixed assets, oil and gas, and geothermal properties	494,536	184,121	2,711	681,368	-	681,368

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	March 31, 2018 (unaudited)					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	1,914,579	9,979,387	1,237,906	13,131,872	-	13,131,872
Inter-segment sales	880,391	26,278	71,956	978,625	(978,625)	-
Total segment revenues	2,794,970	10,005,665	1,309,862	14,110,497	(978,625)	13,131,872
Segment results**)	1,272,870	(28,021)	197,772	1,442,621	(106,222)	1,336,399
Gain on foreign exchange - net						(67,505)
Finance income						48,046
Finance costs						(204,360)
Share in net profit of associates and joint venture						124,893
Other expenses - net						179,927
						81,001
Profit before income tax						1,417,400
Income tax expense - net						(729,633)
Profit for the period after the effect of merging entity's income adjustment						**687,767**
Profit for the year attributable to:						
Owners of the parent						580,351
Non-controlling interests						107,416
Other information						
Segment assets	26,678,114	27,053,836	7,092,514	60,824,464	(5,686,521)	55,137,943
Long-term investments	1,477,012	16,670,182	569,907	18,717,101	(15,668,339)	3,048,762
Total assets	28,155,126	43,724,018	7,662,421	79,541,565	(21,354,860)	58,186,705
Total liabilities	12,410,746	20,267,560	3,671,643	36,349,949	(5,352,812)	30,997,137
Depreciation, depletion and amortization expense	447,889	172,627	130,048	750,564	-	750,564
Additions to fixed assets, oil and gas, and geothermal properties	23,200	229,579	50,884	303,663	-	303,663

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2018					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	7,054,464	45,691,622	5,187,485	57,933,571	-	57,933,571
Inter-segment sales	5,498,100	399,699	266,115	6,163,914	(6,163,914)	-
Total segment revenues	12,552,564	46,091,321	5,453,600	64,097,485	(6,163,914)	57,933,571
Segment results**)	5,960,645	(286,777)	616,351	6,290,219	(43,479)	6,246,740
Gain on foreign exchange - net						19,622
Finance income						256,573
Finance costs						(835,238)
Share in net profit of associates and joint venture						122,724
Other expenses - net						(80,825)
						(517,144)
Profit before income tax						5,729,596
Income tax expense						(3,013,202)
Profit for the period/year after the effect of merging entity's income adjustment						**2,716,394**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						2,572,542
Non-controlling interests						143,852
Other information						
Segment assets	24,620,521	35,093,033	6,655,756	66,369,310	(4,469,912)	61,899,398
Long-term investments	1,472,711	14,970,480	183,158	16,626,349	(13,807,295)	2,819,054
Total assets	26,093,232	50,063,513	6,838,914	82,995,659	(18,277,207)	64,718,452
Total liabilities	10,092,998	26,403,047	3,636,191	40,132,236	(5,023,824)	35,108,412
Depreciation, depletion and amortization expense	1,684,534	715,492	576,536	2,976,562	-	2,976,562
Additions to fixed assets, oil and gas, and geothermal properties	3,110,810	1,135,645	287,056	4,533,511	-	4,533,511

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2017					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	4,489,320	37,000,553	4,510,850	46,000,723	-	46,000,723
Inter-segment sales	3,477,012	372,195	427,098	4,276,305	(4,276,305)	-
Total segment revenues	7,966,332	37,372,748	4,937,948	50,277,028	(4,276,305)	46,000,723
Segment results**)	3,327,892	1,282,198	759,793	5,369,883	(183,477)	5,186,406
Gain on foreign exchange - net						58,137
Finance income						233,074
Finance costs						(817,711)
Share in net profit of associates and joint venture						37,904
Other expenses - net						(830,582)
						(1,319,178)
Profit before income tax						3,867,228
Income tax expense - net						(1,166,824)
Profit for the period/year after the effect of merging entity's income adjustment						**2,700,404**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						2,621,732
Non-controlling interests						78,672
Other information						
Segment assets	23,969,823	28,451,374	8,878,406	61,299,603	(6,831,146)	54,468,457
Long-term investments	1,476,703	16,490,057	451,653	18,418,413	(15,447,495)	2,970,918
Total assets	25,446,526	44,941,431	9,330,059	79,718,016	(22,278,641)	57,439,375
Total liabilities	12,148,638	21,037,697	4,165,216	37,351,551	(6,925,443)	30,426,108
Depreciation, depletion and amortization expense	1,507,444	692,767	603,798	2,804,009	-	2,804,009
Additions to fixed assets, oil and gas, and geothermal properties	3,672,689	1,529,130	221,357	5,423,176	-	5,423,176

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

42. SEGMENT INFORMATION (continued)

	December 31, 2016					
	Upstream	Downstream	Others*)	Total before elimination	Elimination	Total consolidated
External sales	3,542,516	32,337,198	3,932,223	39,811,937	-	39,811,937
Inter-segment sales	2,729,749	140,469	365,653	3,235,871	(3,235,871)	-
Total segment revenues	6,272,265	32,477,667	4,297,876	43,047,808	(3,235,871)	39,811,937
Segment results**)	2,065,679	4,176,180	501,669	6,743,528	(44,098)	6,699,430
Gain on foreign exchange - net						(57,521)
Finance income						336,634
Finance costs						(770,518)
Share in net profit of associates and joint venture						18,722
Other expenses - net						(877,864)
						(1,350,547)
Profit before income tax						5,348,883
Income tax expense						(1,877,649)
Profit for the period/year after the effect of merging entity's income adjustment						**3,471,234**
Profit for the year after the effect of merging entity's income adjustment attributable to:						
Owners of the parent						3,320,382
Non-controlling interests						150,852
Other information						
Segment assets	20,490,777	28,354,356	9,501,653	58,346,786	(7,700,131)	50,646,655
Long-term investments	1,714,743	14,331,318	511,081	16,557,142	(13,227,703)	3,329,439
Total assets	22,205,520	42,685,674	10,012,734	74,903,928	(20,927,834)	53,976,094
Total liabilities	9,422,068	19,894,950	5,185,541	34,502,559	(5,771,223)	28,731,336
Depreciation, depletion and amortization expense	1,568,763	653,572	465,905	2,688,240	-	2,688,240
Additions to fixed assets, oil and gas, and geothermal properties	1,566,871	801,312	644,562	3,012,745	-	3,012,745

*) Others consist of office and housing rentals, hotel operation, air transportation services, health services and operation of hospitals, investment portfolio management, gas transportation services, human resources development and insurance services.

**) Gross profit less sales and marketing expenses, and general and administrative expenses.

Transactions between segments are carried out at agreed terms between the companies.

The following table shows the distribution of the Group's consolidated revenues based on its geographic segments:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Revenue					
Indonesia	11,802,853	12,383,932	54,296,618	44,126,442	38,843,566
Other countries	867,334	747,940	3,636,953	1,874,281	968,371
Consolidated revenues	**12,670,187**	**13,131,872**	**57,933,571**	**46,000,723**	**39,811,937**

Revenue from two customers of the downstream segment for the three-month periods ended March 31, 2019 and 2018 represented approximately 12% and 22% (US$1,416,765 and US$2,533,006) of total sales and other operating revenues, respectively.

All of the Group's assets are substantially located in Indonesia, except for several owned assets outside the country such as PIEP's Subsidiaries which are located in Algeria, Iraq, Malaysia, Italia, France, Myanmar, Canada, Congo, Tanzania, Gabon, Colombia, Namibia, and Venezuela, respectively.

43. OIL AND GAS CONTRACT ARRANGEMENTS

a. PSC

PSCs are entered into by PSC Contractors with SKK Migas (previously BP Migas) acting on behalf of the Government, for a period of 20-30 years, and may be extended in accordance with applicable regulations.

- **Working area**
  The PSC working area is a designated area in which the PSC contractors may conduct oil and gas operations. On or before the tenth year from the effective date of the PSCs, the PSC contractors must return a certain percentage of this designated working area to SKK Migas on behalf of the Government during the term of the PSC.

- **Crude oil and natural gas production sharing**

  Crude oil and natural gas production sharing is determined annually, representing the total liftings of crude oil and gas in each period/year, net of investment credit, FTP, and cost recovery.

  The PSC Contractors are subject to tax on their taxable income from their PSC operations based on their share of equity oil and natural gas production, less bonuses, at a combined tax rate comprising of corporate income tax and dividend tax.

- **Cost recovery**

  Annual cost recovery comprises of:
  i. Current year non-capital costs;
  ii. Current year amortization of capital costs; and
  iii. Unrecovered prior years' operating costs (unrecovered costs).

- **Crude oil and natural gas prices**

  The PSC Contractors' crude oil production is priced at ICP. Natural gas deliveries to third parties and related parties are valued based on the prices stipulated in the respective gas sales and purchase contracts.

- **DMO**

  Crude oil

  The PSC Contractors are required to supply the domestic market in Indonesia with the following annual calculation:

  i. Multiply the total quantity of crude oil produced from the contract area by a fraction, the numerator of which is the total quantity of crude oil to be supplied and the denominator is the entire crude oil production from all petroleum companies in Indonesia.
  ii. Compute 25% of the total quantity of crude oil produced in the PSC's working area.
  iii. Multiply the lower computed, either under (i) or (ii) by the percentage of the contractor's entitlement.

  The price of DMO crude oil is supplied is equal to the weighted average of all types of crude oil sold by the PSC Contractors or other price determined under the PSC.

  Natural gas

  The PSC Contractors are required to supply the domestic market in Indonesia with 25% of total quantity of natural gas produced in the working area multiplied by the PSC contractor's entitlement percentage.

  The price of DMO for natural gas is the price determined based on the agreed contracted sales price.

- **FTP**

  The Government and Contractors are entitled to receive an amount ranging from 10%-20% of the total production of crude oil and natural gas each year, before any deduction for recovery of operating costs and investment credit.

- **Ownership of materials, supplies, and equipment**

  Materials, supplies, and equipment acquired by the PSC contractors for crude oil and natural gas operations belong to the Government. However, the PSC contractors have the right to utilize such materials, supplies, and equipment until they are declared surplus or abandoned with the approval of SKK Migas.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

b. PT Pertamina EP cooperation agreements with SKK Migas

On September 17, 2005, an oil and gas cooperation contract in the form of Pertamina Oil and Gas Contract which is equivalent to a PSC, was signed between Special Task Force For Upstream Oil and Gas Bussiness Activities ("SKK Migas" formerly Oil and Gas Upstream Activities Agency/"BP Migas") and PT Pertamina EP as a successor contract to Pertamina's Petroleum Contract (PPC).This is valid for a period of 30 years from September 17, 2005 until September 16, 2035, which may be extended in accordance with a written agreement between the parties (SKK Migas and PT Pertamina EP) and approval from the Government.

PT Pertamina EP's cooperation contract has the following financial provisions:

- **Working area**

  The area represents the former Pertamina Entity's exploration and production areas excluding Cepu and Randugunting Blocks.

- **Crude oil and natural gas production sharing**

  PT Pertamina EP and the Government's shares of equity (profit) of oil and gas production is 67.2269% and 32.7731%, respectively.

- **FTP**

  The Government and PT Pertamina EP are entitled to receive an amount equal to 5% of the total production of oil and gas each year before any deduction for recovery of operating costs and investment credit. FTP is shared between the Government and PT Pertamina EP in accordance with the entitlements to oil and gas production.

- **Crude and natural gas price**

  Sales of Company's crude are valued with ICP. Transfer of natural gas are valued with decreed price in Gas Sales Agreement ("GSA").

c. PT Pertamina EP cooperation agreements with other parties

PT Pertamina EP has entered into cooperation agreements with other parties in conducting oil and gas activities in certain parts of its PSC working area, under TAC or operating cooperation contracts with the approval of the Government through SKK Migas.

The recoverable costs and shares of equity (profit) of the other parties under the following cooperation agreements form part of PT Pertamina EP's cost recovery under its PSC.

Cooperation agreements with other parties are as follows:

i. Technical Assistant Contract ("TAC")

Under a TAC, operations are conducted through partnership arrangements with PT Pertamina EP. TACs are awarded for fields which are currently in production, or which had previously been in production, but the production has ceased. Crude oil and natural gas production is divided into non-shareable and shareable portions. The non-shareable portion represents the production which is expected from the field (based on the historic production trends of the field) at the time the TAC is signed and accrues to PT Pertamina EP. Non-shareable production decreases annually reflecting expected declines in production. The shareable portion of production corresponds to the additional production resulting from the Partners' investments in the TAC fields.

The Partners are entitled to recover costs, subject to specified annual limitations depending on the contract terms. The remaining portion of shareable production (shareable production less cost recovery) is split between PT Pertamina EP and the Partners. The Partners' share of equity (profit) oil and gas production is stipulated in each contract and ranges from 26.7857% to 35.7143% for oil and 62.5000% for gas.

As of March 31, 2019, there are 7 TAC arrangements of PT Pertamina EP for Sumatera, Java and Papua working areas with contract term for 20 years. The effective term of those contracts range from 2000 until 2002 and the end term of those contracts range from 2020 until 2022.

At the end of the TACs, all TAC assets are transferred to PT Pertamina EP. The TAC Partners are responsible for settling all outstanding TAC liabilities to third parties until the end of the TACs.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

c. PT Pertamina EP cooperation agreements with other parties (continued)

ii. Operation Cooperation Contract ("OC")

In an OC Contract, operations are conducted through partnership arrangements with PT Pertamina EP. OC Contracts are awarded for fields which are currently in production, or which have previously been in production, in which production has ceased, or for areas with no previous production. The two types of OC contracts are:
a. OC Production - Exploration contract
b. OC Production contract

Under an OC Production-Exploration contract, there is no Non-Shareable Oil. While for an OC Production contract, the crude oil production is divided into non-shareable and shareable portions.

The NSO portion of crude oil production represents the production which is expected from the field (based on the historic production trends of the field) at the time the OC contract is signed, and it accrues to PT Pertamina EP. The shareable portion of crude and gas production corresponds to the additional production resulting from the Partners' investments in the OC contract fields and split between the parties in the same way as under a cooperation contract. In certain OC production contracts, in the event that the production is the same as or less than the NSO, the Partner's production cost shall not be deferred and will be recovered with the following provisions:

Partner may recover the operating costs in any Calendar Year if the amount of the Partner's production is greater than the Non-Sharable Oil up to a maximum of Incremental Oil that comprises of:

1) Cost recovery for lifting Non-Shareable Oil up to a maximum of 80% (eighty percent) from Operating Costs of Non-Shareable Oil.

2) Cost recovery for lifting incremental oil up to a maximum of 80% (eighty percent) from the production of Incremental Oil produced and sold and that were not used in that Calendar Year.

If, in any Calendar Year, the operating costs exceed the value of such crude oil allocated for the Operations in that Calendar Year, then the unrecovered excess will be recovered in the following years.

The Partner's share of equity (profit) oil and gas production as stipulated in each contract ranges from 16.6667% to 29.8039% for oil and 28.8627% to 53.5714% for gas, respectively.

Specified investment expenditure commitments are required to be made in the first three years after the signing of the OC contract. To ensure that these expenditure commitments are met, the Partners are required to provide PT Pertamina EP with irrevocable and unconditional bank guarantees. The OC Partners are also required to make payments to PT Pertamina EP before the date of signing the OC contracts, of the amounts stated in the bid documents.

As of March 31, 2019, there are 27 OC partnership arrangements of PT Pertamina EP for Sumatera, Java, Kalimantan and Papua working area with contract term for 15-20 years. The effective term of those contracts range from 2007 until 2018 and the end term of those contracts range from 2022 until 2035.

At the end of OC contracts, all OC assets are transferred to PT Pertamina EP. The OC Partners are responsible for settling all outstanding OC liabilities to third parties until the end of the OC contracts.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

c. PT Pertamina EP cooperation agreements with other parties (continued)

iii. Unitisation Agreement

In accordance with Government Regulation No. 35 Year 2004 on Upstream Oil and Gas Business Activities, a PSC contractor is required to conduct unitisation if it is proven that its reservoir extends into another contractor's Working Area. The MoEMR will determine the operator for the unitisation based on the agreement between the contractors entering the unitisation after considering the opinion of SKK Migas.

As of March 31, 2019, there are 6 Unitisation arrangements of PT Pertamina EP for Sumatera, Java and Papua working area with contract term for 10-50 years. The effective term of those contracts range from 1985 until 2013 and the end term of those contracts range from 2023 until 2035.

Based on SKK Migas Letter No. SRT-0493/SKKMA0000/2018/S1 dated June 25, 2018, regarding the Establishment of New Unitization Operators in Sukowati Field, CPA Mudi Production Facilities and FSO Cinta Natomas, the PT Pertamina EP was appointed as the new operator Sukowati Field (Note 4h).

d. PHE's cooperation agreement with other parties

- Gross split contract

On January 13, 2017, the regulation of the Minister of Energy and Mineral Resources No.08/2017 regarding principles of the Production Sharing Contract without Cost Recovery Mechanism, also known as Gross Split PSC was issued.

In Gross Split PSC the sharing of oil and gas production between the Government of Indonesia and the Contractors is based on the following 3 criteria:

1. Base Split
2. Variable Split
3. Progressive Split

The Government has also arranged matters related to Gross Split PSC as follows:

i. The tax regime applicable to the Gross Split PSC is in accordance with the provisions of the income tax law;
ii. The contractors of Gross Split PSC must reimburse unrecovered investment costs to the old PSC contractors.
iii. The oil and gas assets of the old PSC which are now owned by the Directorate General of State Assets ("DJKN") are to be used by the Gross Split PSC contractors based on lease scheme.
iv. Leases are levied on oil and gas assets used by the Gross Split PSC contractors and have the cost recovery, then the fair value is recalculated based on the Indonesian Appraisal Standard by the Public Appraiser, multiplied by the rental rate set by the DJKN.

As of March 31, 2019, the signed gross split PSC is as follows:

PSC partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
MUJ ONWJ	Offshore North West Java Block	North West Java	19/01/2017	27/08/1971	18/01/2037	90%	Oil and gas	20 years
None	Tuban Block	East Java	20/05/2018	12/02/1997	19/05/2038	100%	Oil and gas	20 years
None	Ogan Komering Block	South Sumatera	20/05/2018	11/07/1991	19/05/2038	100%	Oil and gas	20 years
None	Offshore Southeast Sumatera Block	Southeast Sumatera	06/09/2018*	1975	06/09/2038	100%	Oil and gas	20 years
None	NSO Block	North Sumatera Offshore	17/10/2018*	01/10/2015	16/10/2038	100%	Oil and gas	20 years
None	Raja/Pendopo Block	South Sumatera	06/07/2019**	21/11/1992	05/07/2039	100%	Oil and gas	20 years
None	Jambi Merang Block	Jambi	10/02/2019**	22/02/2011	09/02/2039	100%	Oil and gas	20 years
Eni East Sepinggan Ltd.	East Sepinggan Block	East Sepinggan	20/7/2012***	-	20/07/2042	15%	Oil and gas	30 years

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

d. PHE's cooperation agreement with other parties (continued)

PSC partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
Petrogas (Basin) Ltd.	Kepala Burung Block	Papua	15/10/2020****	07/10/1996	14/10/2040	30%	Oil and gas	20 years
Petrogas (Island) Ltd.	Salawati Block	Papua	23/04/2020****	21/01/1993	22/04/2040	30%	Oil and gas	20 years
None	Maratua Block	North Kalimantan & East Kalimanta	18/02/2019	-	17/02/2049	100%	Oil and gas	30 years

* Gross Split PSC was signed on April 20, 2018
** Gross Split PSC signed on May 31, 2018
*** The PSC amendment to Gross Split PSC was signed on December 11, 2018
**** Gross Split PSC was signed on July 11, 2018

- **Indonesian participation arrangements ("IP")**

  Through the IP arrangements, the Company, a State-Owned Enterprise, is offered a 10% working interest in PSCs at the first time Plans of Development ("POD") which was approved by the Government of Indonesia (the "Government"), represented by SKK Migas. The 14.28% interest in Jabung Block represents the acquisition of additional interest of 4.28% by the Company. The 5% interest in the Tengah Block represents 10% of the 50% foreign contractor's share. The Company assigned these IP interests to PHE's subsidiaries on January 1, 2008.

  As of March 31, there are 5 IP partnership arrangements of PHE for Sumatera, Kalimantan and Papua working area with contract terms of 20-30 years. The effective term of those contracts ranges from 1990 until 2005 and the end term of those contracts ranges from 2020 until 2028 with percentage of participation range from 10% until 14.28%.

- **PSC interests acquired after the issuance of Law No.22 year 2001, related to Oil and Gas**

  1. **Oil and gas**

     As of March 31,2018, there are 16 oil and gas partnership arrangements of PHE for Sumatera, Java, Kalimantan, Sulawesi, Maluku and Papua working area with contract terms of 20-30 years. The effective term of those contracts range from 1998 until 2016 and the end term of those contracts ranges from 2019 until 2046 with percentage of participation ranging from 15% until 100%.

  2. **Coal bed methane**

     As of March 31, 2019, there are 13 Coal Bed Methane ("CBM") partnership arrangements in exploration activities for Sumatera and Kalimantan working areas, with contract terms of 30 years. The effective terms of those contracts ranges from 2008 until 2012, and the end term of those contracts ranges from 2038 until 2042 with percentages of participation range from 27.5% until 100%.

  3. **Unconventional oil and gas**

     As of March 31, 2019, there are 2 Unconventional Oil and Gas partnership arrangements for Sumatera working areas with contract term of 30 years. The effective term of those contracts ranges from 2013 until 2015, and the end term of those contracts ranges from 2043 until 2045 with percentages of participation interests range from 50% until 100%.

- **Joint operating body-production sharing contracts ("JOB-PSC")**

  In a JOB-PSC, operations are conducted by a joint operating body between PHE's Subsidiaries and the contractors. The PHE Subsidiaries' share of expenditures is paid in advance by the contractors and repaid by PHE's Subsidiaries out of their share of crude oil and natural gas production, with a 50% uplift. After all expenditures are repaid, the crude oil and natural gas production is divided between PHE's subsidiaries and the contractors based on their respective percentages of participation in the JOB-PSC. The contractors' share of crude oil and natural gas production is determined in the same manner as for a PSC.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

d. PHE's cooperation agreement with other parties (continued)

- **Joint operating body-production sharing contracts ("JOB-PSC") (continued)**

As of March 31, 2019, there are 4 JOB-PSC Partnership arrangements of PHE for Sumatera, Java, Kalimantan, Sulawesi, and Papua working area with contract terms of 30 years. The effective term of those contracts ranges from 1989 until 1998, and the end term of those contracts ranges from 2019 until 2028 with percentage of participation ranging from 37.5% until 50%.

- **Pertamina participating interests ("PPI")**

Through PPI arrangements, PHE owns working interests in contracts similar to JOB-PSC contracts. The remaining working interests are owned by a contractor who acts as an operator. PHE's share of expenses is either funded by PHE on a current basis, or paid in advance by the contractors and repaid by PHE out of their share of crude oil and natural gas production, with a 50% uplift. The crude oil and natural gas production are divided between PHE and the contractors based on their respective percentages of participation in the PSC. The contractors' share of crude oil and natural gas production is determined in the same manner as for a PSC.

As of March 31, 2019, the Subsidiaries' PPI arrangements were as follows (unaudited):

PPI partners	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
Conoco Philips (South Jambi) Ltd. and Petrochina International Jambi B Ltd.	B Block	South Jambi	26/01/1990	26/09/2000	25/01/2020	25%	Oil and gas	30 years

- **Foreign oil and gas contract interests**

Name of JOC	JOB partners	Working area	Area	Effective date of contract	Production commencement date	Percentage of participation	Production	Contract period
Petronas Carigali Pertamina Petro-Vietnam Operating Company Sdn. Bhd. ("PCPP")	Petronas Carigali Sdn. Bhd., Petrovietnam	Offshore Sarawak Block (SK 305)	Malaysia	16/06/2003	26/07/2010	30%	Oil and gas	29 years

- **Unitization agreements**

In accordance with Government Regulation No. 35 Year 2004 on Upstream Oil and Gas Business Activities, a contractor is required to conduct unitization if it is proven that its reservoir extends into another Contractor's Working Area. The Minister of Energy and Mineral Resources will determine the operator for the unitization based on the agreement between the contractors entering the unitization agreements after considering the opinion of SKK Migas.

Since several of PHE Subsidiaries' oil and gas reservoirs extend into other Contractors' Working Areas, PHE Subsidiaries entered into unitization agreements with several contractors.

As of March 31, 2019, there are 6 unitization agreements of PHE for Sumatera, Java, Kalimantan, and Papua working areas, with contract terms ranging from 10-50 years. The effective term of those contracts ranges from 1985 until 2014, and the end term of those contracts ranges from 2019 until 2035.

- **Extension and termination of PHE cooperation contract**

PSC "B" ended on October 3, 2018. On September 25, 2018, the Government, through the Aceh Oil and Gas Management Agency (BPMA), appoints PHE NSB as operator of the "B" Working Area for 6 (six) months from October 4, 2018 or until PSC has just been signed, whichever occurs first, with the basic forms and provisions of PSC in accordance with the current "B" Working Area.

The Tengah Block PSC ended on October 4, 2018. The Government decides not to extend the management of the Tengah Working Area by the existing Contractor. Until these consolidated financial statements were prepared, PHE Tengah K together, with other contractors (Total Tengah and Inpex Tengah Ltd.), are still in the process of completing their rights and obligations after termination with the Government.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

e. PT Pertamina EP Cepu (PEPC)'s cooperation agreements with other parties

On September 17, 2005, a Cooperation Contract ("PSC") was signed between SKK Migas and PEPC (50% participating interest), MCL (25.50% participating interest) and Ampolex (24.50% participating interest) (jointly called a Contractor) for a period of 30 years from September 17, 2005 to September 16, 2035, and may be extended in accordance with applicable regulations. The conditions for PSC PEPC are as follows:

SC Partner	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
ExxonMobil Cepu Limited Ampolex (Cepu) Pte. Ltd. PT Sarana Patra Hulu Cepu PT Petrogas Jatim Utama Cendana PT Blora Patragas Hulu PT Asri Dharma Sejahtera	Cepu Block	Central Java-West Java	17/09/2005	31/08/2009	16/09/2035	45%	Oil	30 years

- Unitisation agreements

As of March 31, 2019, the Subsidiaries' unitization agreements are as follows:

Partner	Working area	Area	Effective date of contract	Production commencement date	Expiry date of contract	Percentage of participation	Production	Contract period
PT Pertamina EP	EP Block Cepu Block	Central Java - East Java	17/09/2005	-	16/09/2035	91.9399%	Gas	30

f. PT Pertamina EP Cepu Alas Dara Kemuning (PEPCADK) cooperation agreements with SKK Migas

The PSC was entered into by PEPC ADK with SKK Migas action on behalf of the Government on February 26, 2014 for a period of 30 years from February 26, 2014 until February 25, 2044. The period may be extended in accordance with applicable regulations. The Company has a 100% participating interest in the Alas Dara Kemuning Block PSC.

g. PT Pertamina Hulu Indonesia ("PHI") cooperation agreements with SKK Migas

- PSC

PSC is made by PSC contractors with the Government through the Special Task Force for Upstream Oil and Gas Business Activities ("SKK Migas" - formerly the Executive Agency for Upstream Oil and Gas Business Activities/"BP MIGAS") for a contract period of 20-30 years . This period can be extended in accordance with applicable regulations.

As of March 31, 2019, PHI Group's PSC are as follows:

PSC partner	Working area	Area	Contract effective date	Starting production date	Expiry date of contract	Partnership percentage	Production	Contract period
None	Mahakam Block	Onshore and Offshore East Kalimantan	01/01/2018	01/01/2018	31/12/2037	100%	Oil and gas	20 years

- Gross Split PSC

PSC partner	Working area	Area	Contract effective date	Starting production date	Expiry date of contract	Partnership percentage	Production	Contract period
None	Sanga Sanga Block	Onshore East Kalimantan	08/08/2018*	08/08/2018	07/08/2038	100%	Oil and gas	20 years
None	East Kalimantan and Attaka Block	Onshore and Offshore East Kalimantan	25/10/2018*	25/10/2018	24/10/2038	100%	Oil and gas	20 years

* Contract was signed on April 20, 2018.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

g. PT Pertamina Hulu Indonesia ("PHI") cooperation agreements with SKK Migas (continued)

- **Unitisation agreements**

On March 31, 2019, PHI's has unitisation agreements as follows:

Parties	Operator	Field	Location	Signing date of contract	Start contract	Production	End contract	Contract period
PT Pertamina Hulu Mahakam (PHM) & Pertamina Hulu Sanga Sanga (PHSS)	PT Pertamina Hulu Sanga Sanga (PHSS)	Nilam & Badak	East Kalimantan (KKS Mahakam and KKS Sanga Sanga)	In Progress	08/08/2018	08/08/2018	31/12/2037	20 years
PT Pertamina Hulu Mahakam (PHM) & Pertamina Hulu Kalimantan Timur (PHKT)	PT Pertamina Hulu Mahakam (PHM)	Peciko	East Kalimantan (KKS Mahakam and KKS East Kalimantan)	In Progress	25/10/2018	25/10/2018	31/12/2037	20 years

h. PIEP's directly and indirectly held foreign oil and gas PSC interests

As of March 31, 2019, the Company's directly and indirectly held foreign oil and gas PSCs or similar interests were as follows:

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commencement of production	Percentage of participation	Production	Contract period
Menzel Lejmat North (MLN)	Talisman Energy Inc	405a Block	Algeria	2000	2003	65%	Oil	25 years
Murphy Sabah Oil Co. Ltd.	Murphy Sabah Oil Co. Ltd. Petronas Carigali Sdn. Bhd.	Block K	Malaysia	27/01/1999	2007	24%	Oil and natural gas	38 years
Murphy Sabah Oil Co. Ltd.	Murphy Sabah Oil Co. Ltd. Petronas Carigali Sdn. Bhd.	Block H	Malaysia	19/03/2007	Development stage	24%	Natural gas	38 years
Murphy Sarawak Oil Co. Ltd.	Murphy Sarawak Oil Co. Ltd. Petronas Carigali Sdn. Bhd.	SK309	Malaysia	27/01/1999	2003	25.5%	Oil, natural gas, and condensate	29 years
Murphy Sarawak Oil Co. Ltd.	Murphy Sarawak Oil Co. Ltd. Petronas Carigali Sdn. Bhd.	SK311	Malaysia	27/01/1999	2007	25.5%	Oil, natural gas, and condensate	29 years
Murphy Sarawak Oil Co. Ltd.	Murphy Sarawak Oil Co. Ltd. Petronas Carigali Sdn. Bhd.	SK314A	Malaysia	07/05/2013	Exploration stage	25.5%	-	27 years
Mnazi Bay Exploration Mnazi Bay Development/ Production	M&P (Operator); TPDC	Mnazi Bay	Tanzania	October 2006	August 2015	60.075% & 48.06%	Gas	2031 and can be extended up to 2051
Enzanga Production	M&P (Operator); The Gabonese Republic; Tullow	Ezanga	Gabon	January 1, 2014	2007	80%	Oil	2034 and can be extended up to 2054
Seplat Petroleum Development Company Plc	Seplat (Operator); NPDC	OML 4, 38, 41	Nigeria	June 30, 1989	July 2010	45%	Oil and gas	October 2038
	Pillar Oil (Operator); Seplat	OPL 283	Nigeria	2009	May 2012	40%	Oil	Oktober 2028
	Seplat and NNPC (Joint Operators)	OML 53	Nigeria	1997	1978	40%	Oil	June 2027
	Seplat and BelemaOil (Joint Operators); NNPC	OML 55	Nigeria	1997	February 2017	n/a*)	Oil	June 2027
Petroregional del Lago Mixed Company	Petroleos de Venezuela S.A. & PDVSA Social	Urdaneta West Field	Venezuela	2006	1974	40%	Oil	2026

*) Under the revised commercial terms in relation to OML 55, starting July 2016, Seplat will no longer be a shareholder in BelemaOil but will instead receive interest income until a total sum of US$330 million has been paid to Seplat. Working interest production reported for OML 55 is preceding volumes to end June 2016.

43. OIL AND GAS CONTRACT ARRANGEMENTS (continued)

h. PIEP's directly and indirectly held foreign oil and gas PSC interests (continued)

- **Technical service contract ("TSC")**

As of March 31, 2019, TSC participating interest held by PT Pertamina Irak Eksplorasi Produksi ("PIREP") were as follows:

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commence-ment of production	Percentage of participation	Production	Contract period
West Qurna 1 Field Operating Division	ExxonMobil Iraq Limited, Shell Iraq B.V. PetroChina International Iraq FZE, Oil Exploration Company of Iraqi Ministry of Oil	West Qurna 1 Block	Iraq	25/01/2010	25/01/2010	10%	Oil	35 years

- **Unitisation agreements**

As of March 31, 2019, PIEP's unitization agreements are as follows:

1. Algeria

Name of JV	JV partners	Working area	Country	Effective date of contract	Date of commence-ment of production	Percentage of participation	Production	Contract period
El Merk ("EMK")	Talisman (Algeria) B.V., Sonatrach, Anadarko, Eni, Maersk, Company	405a Block	Algeria	March 2007	2013	16.90%	Oil, Condensate, and LPG	25 years
Ourhoud	Talisman (Algeria) B.V., . Sonatrach, Anadarko, Eni, Maersk, Company	405a Block	Algeria	December 1997	2002	3.56%	Oil	25 years

2. Malaysia

Parties	Operator	Unit field	PMEP's percentage of participation	Effective date of contract	Date of commencement of production	Production	Contract period
Shell, Conoco Phillips, Carigali Murphy, PMEP	Shell	Gumusut Kakap Field	3.25%	20/09/2004	18/11/2012	Oil and natural gas	Not specified
Shell, Conoco Phillips, Carigali, Murphy, PMEP	Murphy	Siakap North Petai Field	9.6%	01/01/2007	28/02/2014	Oil and natural gas	Not specified

i. PGN Cooperation Agreement

As of March 31, 2019, PGN has interests in the following oil and gas joint operations or Service Contracts Participation and Economic Sharing Agreements:

Work Area	Country	Participating Interest
Ujung Pangkah Block	Indonesia	100.00%
South Sesulu Block	Indonesia	100.00%
Fasken Block	United States of America	36.00%
Bangkanai Block	Indonesia	30.00%
West Bangkanai Block	Indonesia	30.00%
Muriah Block	Indonesia	20.00%
Ketapang Block	Indonesia	20.00%
Muara Bakau Block	Indonesia	11.67%
Wokam II Block	Indonesia	100.00%
Pekawai Block	Indonesia	100.00%
West Yamdena Block	Indonesia	100.00%

44. GEOTHERMAL WORKING AREAS

Since 1974, the former Pertamina Entity has been assigned geothermal working areas in Indonesia based on various decision letters issued by the Minister of Mines and Energy. In accordance with Government Regulation No. 31 Year 2003, all rights and obligations arising from the contracts and agreements entered into between former Pertamina Entity and third parties, so long as these are not contrary to Law No. 22 Year 2001, were transferred to Pertamina Entity effective September 17, 2003. Pertamina Entity through its letter No. 282/C00000/2007-S0 dated March 12, 2007 assigned its geothermal working areas to PGE effective from January 1, 2007. The transfer of Pertamina Entity's rights, obligations, and interests in geothermal business operations to PGE was approved by the MoEMR in Letters No. 2198/30/DJB/2009 dated August 4, 2009 and No. 2523/30/DJB/2009 dated September 1, 2009.

Effective from June 28, 2010, Pertamina Entity's geothermal assets were transferred to PGE, and formed part of Pertamina Entity's contribution to PGE's additional paid-up capital. This transfer of Pertamina Entity's geothermal assets were documented in Notarial Deed No. 23 dated June 28, 2010 of Lenny Janis Ishak, S.H.

Based on the Decree of the Minister of Mines and Energy No. 2067 K/30/MEM/2012, regarding the affirmation of the territory of power and changes in the coordinate boundaries of the exploitation of geothermal resources, PT Pertamina Geothermal Energy has management rights over 14 geothermal WKPs. Referring to the original provision the Law No. 21 article 78 of 2014 regarding Geothermal Energy, at the end of 2014, 2 (two) WKPs, namely Kotamobagu and Gunung Iyang Argopuro were returned to the Government because the two WKPs up to December 31, 2014, were still not in the Exploitation stage. Furthermore, Pertamina received two (2) new WKPs, namely Mount Lawu (based on ESDM Ministerial Decree No.35.K/30/MEM/2016) and Seulawah (based on the Auction Winner Determination Letter from Aceh Governor No. 541/53157 November 1, 2013). PGE will carry out exploration activities in the two new WKPs.

The operations of the above geothermal working areas are conducted through own operations and joint operating contracts.

As of March 31, 2019, PGE's geothermal working areas were as follows:

a. Own operation

The following working areas are operated by PGE:

Working area	Location	Field status
Gunung Sibayak-Gunung Sinabung	Sibayak, North Sumatra	Production
Kamojang-Darajat	Kamojang, West Java	Production
Lahendong	Lahendong, North Sulawesi	Production
Gunung Way Panas	Ulubelu, Lampung	Production
Karaha-Cakrabuana	Karaha, West Java	Production
Lumut Balai and Marga Bayur	Lumut Balai, South Sumatera	Development
Hululais	Hululais, Bengkulu	Development
Sungai Penuh	Sungai Penuh, Jambi	Exploration
Gunung Lawu	Central Java	Exploration
Seulawah Agam	Aceh	Exploration

44. GEOTHERMAL WORKING AREAS

b. Joint operating contracts ("JOCs")

JOCs include geothermal activities in PGE's working areas that are conducted by third parties. In accordance with the JOCs, PGE is entitled to receive production allowances from the JOC contractors at the rate of 2.66% for the Darajat JOC and 4% for the Salak, Wayang Windu, Sarulla, and Bedugul JOCs of the JOC contractors' annual net operating income as calculated in accordance with the JOCs.

As of March 31, 2019, PGE's JOCs were as follows:

Working Area	Location	Field Status	Contractor
Cibeureum - Parabakti	Salak, West Java	Production	Star Energy Geothermal Salak Ltd. and Star Energy Geothermal Salak Pratama Ltd.
Pangalengan	Wayang Windu, West Java	Production	Star Energy Geothermal (Wayang Windu) Ltd.
Kamojang-Darajat	Darajat, West Java	Production	Star Energy Geothermal Darajat II Ltd.
Gunung Sibualbuali	Sarulla, North Sumatera	Production	Sarulla Operation Limited
Tabanan	Bedugul, Bali	Exploration	Bali Energy Ltd.

PGE's income from geothermal activities is subject to tax (government share) at the rate of 34% for the Work Area managed before the Law No. 21 of 2014 regarding Geothermal was issued.

45. GOVERNMENT AUDIT

PT Pertamina EP, PT Pertamina EP Cepu, subsidiaries of PT Pertamina Hulu Energi

The accounting policies stipulated in the PSC are subject to interpretation by SKK Migas and the Government. Every year, the accounting records and financial information from all PSC are subject to audit by SKK Migas and/or the Government. Claims arising from the audit will be approved by the PSC operator and recorded in accounting accounting by the PSC or further discussed with SKK Migas and/or the Government. The settlement of the claims discussed requires a long negotiation process.

Management believes that the audit results for PT Pertamina EP Cooperation Contract and other PSC, wherein PT Pertamina EP Cepu and the subsidiaries of PT Pertamina Hulu Energi have the a Participating Interest, will not have a material impact on the Group's financial position and cash flows.

46. ADDITIONAL INFORMATION RELATED TO CASH FLOW

a. Activities that do not affect cash flow

	March 31, 2019 (Unaudited)	December 31, 2018	2017	2016
Increase/decrease in finance lease assets under fixed assets (Note 13)	(34,280)	19,828	103,022	(5,287)
Capitalization of borrowing costs to fixed assets (Note 13)	1,704	31,500	25,611	16,689
Capitalization of borrowing costs to oil and gas and geothermal properties (Note 14)	6,416	24,885	32,338	33,098
Addition (deduction) in oil and gas property arising from provision for decommissioning and site restoration (Note 23)	21,507	87,035	51,498	82,270

46. ADDITIONAL INFORMATION RELATED TO CASH FLOW (continued)

b. Reconciliation of liabilities from financing activities

	January 1, 2019	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	March 31, 2019 (unaudited)
Short term loans	4,347,035	(806,473)	-	130,835	-	3,671,397
Dividend payable	-	-	-	-	-	-
Long term liabilities	2,225,877	(130,889)	-	(16,550)	(3,224)	2,075,214
Bonds payable	11,094,096	-	-	-	5,711	11,099,807
Total liabilities from financing activities	**17,667,008**	**(937,362)**	**-**	**114,285**	**2,487**	**16,846,418**

	January 1, 2018	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	March 31, 2018 (unaudited)
Short term loans	452,879	86	-	(9,541)	-	443,424
Dividend payable	-	-	-	-	-	-
Long term liabilities	2,475,726	(157,383)	-	4,395	(6,133)	2,316,605
Bonds payable	10,385,873	-	-	-	3,534	10,389,407
Total liabilities from financing activities	**13,314,478**	**(157,297)**	**-**	**(5,146)**	**(2,599)**	**13,149,436**

	January 1, 2018	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2018
Short term loans	452,879	3,905,941	-	(11,785)	-	4,347,035
Dividend payable	-	(585,755)	614,939	(29,184)	-	-
Long term liabilities	2,475,726	(209,420)	-	(46,045)	5,616	2,225,877
Bonds payable	10,385,873	696,758	-	-	11,465	11,094,096
Total liabilities from financing activities	**13,314,478**	**3,807,524**	**614,939**	**(87,014)**	**17,081**	**17,667,008**

	January 1, 2017	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2017
Short term loans	230,293	252,810	-	(30,224)	-	452,879
Dividend payable	-	(867,751)	907,383	(39,632)	-	-
Long term liabilities	3,439,109	(820,834)	-	(148,909)	6,360	2,475,726
Bonds payable	9,772,656	-	-	-	613,217	10,385,873
Total liabilities from financing activities	**13,442,058**	**(1,435,775)**	**907,383**	**(218,765)**	**619,577**	**13,314,478**

	January 1, 2016	Cash Flows	Non-Cash Changes: Dividend declare	Non-Cash Changes: Foreign exchange	Non-Cash Changes: Others	December 31, 2016
Short term loans	1,807,955	(1,680,626)	-	102,964	-	230,293
Dividend payable	-	(554,859)	499,449	55,410	-	-
Long term liabilities	4,065,515	(573,920)	-	(55,858)	3,372	3,439,109
Bonds payable	9,910,726	(139,756)	-	-	1,686	9,772,656
Total liabilities from financing activities	**15,784,196**	**(2,949,161)**	**499,449**	**102,516**	**5,058**	**13,442,058**

47. FINANCIAL ASSETS AND LIABILITIES

a. Financial instruments category and fair value measurements

The following tables from to the Group's financial assets and liabilities by category:

	Financial Assets				
	Fair value through profit or loss	Avalable for sale	Loan and receivable	Held to maturity	Total
March 31, 2019 (unaudited)					
Cash and cash equivalents	-	-	8,322,110	-	8,322,110
Restricted cash	-	-	109,337	-	109,337
Short-term investments	19,124	278,084	1,213	-	298,421
Other investments - net	-	85,089	-	-	85,089
Long-term investments	-	16,001	1,532	541,974	559,507
Trade receivables	-	-	3,724,223	-	3,724,223
Due from the Government	-	-	5,566,906	-	5,566,906
Other receivables	-	-	945,222	-	945,222
Other non-current assets	-	-	1,186,467	-	1,186,467
Total Financial Assets	**19,124**	**379,174**	**19,857,010**	**541,974**	**20,797,282**
December 31, 2018					
Cash and cash equivalents	-	-	9,112,312	-	9,112,312
Restricted cash	-	-	108,915	-	108,915
Short-term investments	20,534	202,195	2,470	-	225,199
Other investments - net	-	80,171	-	-	80,171
Long-term investments	-	15,991	1,530	532,370	549,891
Trade receivables	-	-	3,231,106	-	3,231,106
Due from the Government	-	-	4,758,409	-	4,758,409
Other receivables	-	-	883,490	-	883,490
Other non-current assets	-	-	1,149,976	-	1,149,976
Total Financial Assets	**20,534**	**298,357**	**19,248,208**	**532,370**	**20,099,469**
December 31, 2017					
Cash and cash equivalents	-	-	6,409,827	-	6,409,827
Restricted cash	-	-	119,671	-	119,671
Short-term investments	24,898	208,894	15,490	-	249,282
Other investments - net	-	27,328	-	-	27,328
Long-term investments	-	16,034	1,523	533,309	550,866
Trade receivables	-	-	2,675,643	-	2,675,643
Due from the Government	-	-	2,155,739	-	2,155,739
Other receivables	-	-	875,514	-	875,514
Other non-current assets	-	-	1,292,628	-	1,292,628
Total Financial Assets	**24,898**	**252,256**	**13,546,035**	**533,309**	**14,356,498**
December 31, 2016					
Cash and cash equivalents	-	-	6,721,568	-	6,721,568
Restricted cash	-	-	122,697	-	122,697
Short-term investments	18,008	111,467	1,345	-	130,820
Other investments - net	-	43,190	-	-	43,190
Long-term investments	-	107,649	1,517	534,834	644,000
Trade receivables	-	-	2,864,720	-	2,864,720
Due from the Government	-	-	1,792,457	-	1,792,457
Other receivables	-	-	892,637	-	892,637
Other non-current assets	-	-	943,178	-	943,178
Total Financial Assets	**18,008**	**262,306**	**13,340,119**	**534,834**	**14,155,267**

47. FINANCIAL ASSETS AND LIABILITIES (continued)

a. Financial instruments category and fair value measurements (continued)

The following tables from to the Group's financial assets and liabilities by category: (continued)

	Other Financial Liabilities			
		December 31,		
	March 31, 2019	2018	2017	2016
Short-term loans	(3,671,397)	(4,347,035)	(452,879)	(230,293)
Trade payables	(3,290,095)	(3,676,558)	(3,949,398)	(3,409,205)
Due to the Government	(2,516,044)	(2,002,825)	(1,831,245)	(1,685,118)
Accrued expenses	(2,115,141)	(1,902,515)	(1,759,885)	(1,473,189)
Long-term liabilities	(2,075,214)	(2,225,877)	(2,475,726)	(3,439,109)
Other payables	(362,729)	(407,196)	(467,742)	(269,731)
Bonds payable	(11,099,807)	(11,094,096)	(10,385,873)	(9,772,656)
Other non-current payables	(88,419)	(149,428)	(69,812)	(56,431)
Total Financial Liabilities	**(25,218,846)**	**(25,805,530)**	**(21,392,560)**	**(20,335,732)**

The Company

The Company entered into a foreign exchange and derivative line agreement with BNI, Mandiri and BRI in order to hedge against exchange rate risk. The notional amount for the three-month periods ended March 31, 2019 and the years ended December 31, 2018, 2017, and 2016 were US$336,000, US$570,000, US$355,000, and US$102,050, respectively.

The fair value of these financial liabilities is estimated using appropriate valuation techniques with inputs that are not based on observable market data.

The Company hedges the changes in the fair value of its liability due to risk of the foreign exchange rate fluctuation of Rupiah and US Dollar. The net changes in the fair values of the above derivatives instrument for the three-month periods ended March 31, 2019 and the years ended December 31, 2018, 2017, and 2016 were US$2,369, US$3,044, US$847, and US$155, respectively.

Subsidiaries

PGN entered into a cross currency swap contract with ABN AMRO Bank N.V., currently The Royal Bank of Scotland N.V. This contract ended on March 15, 2019. The notional amount for the years ended December 31, 2018, 2017, and 2016 were US$175,843, US$144,033, and US$139,178, respectively.

Fair value of this financial liabilities is estimated using appropriate valuation techniques with inputs that are not based on observable market data.

PGN hedges the changes in the fair value of its liability due to risk of the foreign exchange rate fluctuation of Japanese Yen and US Dollar. The net changes in the fair values of the above derivatives instrument for the the years ended December 31, 2018, 2017, and 2016 were US$1,936, US$1,867, and US$2,129, respectively.

These transaction do not meet the hedge accounting criteria according to Indonesian Financial Accounting Standard.

47. FINANCIAL ASSETS AND LIABILITIES (continued)

b. Offsetting financial assets and liabilities

The following financial instruments are subject to offsetting, enforceable master netting arrangements and similar agreement:

	Gross amount of recognized financial assets	Gross amount of recognized financial assets set off in the statement of financial position	Net amount of financial assets presented in the statement of financial position	Related amounts not set off in the statement of financial position		Net amount
				Financial instruments	Cash collateral received	
March 31, 2019 (unaudited)						
Financial Asset						
- Trade receivable	3,757,514	(33,290)	3,724,224	-	-	3,724,224
Financial Liabilities						
- Trade payable	3,323,385	(33,290)	3,290,095	-	-	3,290,095
December 31, 2018						
Financial Asset						
- Trade receivable	3,327,292	(96,186)	3,231,106	-	-	3,231,106
Financial Liabilities						
- Trade payable	3,772,744	(96,186)	3,676,558	-	-	3,676,558
December 31, 2017						
Financial Asset						
- Trade receivable	2,736,501	(60,858)	2,675,643	-	-	2,675,643
Financial Liabilities						
- Trade payable	4,010,256	(60,858)	3,949,398	-	-	3,949,398
December 31, 2016						
Financial Asset						
- Trade receivable	2,899,983	(35,263)	2,864,720	-	-	2,864,720
Financial Liabilities						
- Trade payable	3,444,468	(35,263)	3,409,205	-	-	3,409,205

For financial assets and liabilities subject to enforceable master netting arrangements or similar arrangements above, each agreement between the Group and the counterparty allows for net settlement of the relevant financial assets and liabilities when both choose to settle on a net basis. In the absence of such an election, financial assets and liabilities will be settled on gross basis, however, each party to the master netting agreement or similar agreement will have the option to settle all such amounts on a net basis in the event of default of the other party.

48. RISK MANAGEMENT POLICY

The Group has various business activities, which expose it to various potential risks. The Group's overall risk management program focuses on minimising potential adverse effects on the financial performance of the Group.

Risk management is carried out by the Group's Board of Directors, specifically the Risk Management Committee ("the Committee"), Risk Management Unit and Risk Taking Unit to identify, assess, mitigate and monitor the risks of the Group. The Committee provides principles for overall risk management, including business risk and financial risk.

a. Business risks

The Group's business activities are exposed to a variety of business risks (upstream and downstream) which are as follows:

i. The Group is subject to the control of the Government and there is no guarantee that the Government will always act in the Group's best interest. The Group also derives certain benefits from being a state-owned entity, and the Group cannot guarantee that any or all of these benefits will continue.
ii. The Group is subject to audit by SKK Migas, BPK, DGT and/or the Government. The outcome of the assessment may result in claims against the Group or reduce claims against the Government that have already been recognized by the Group.

48. RISK MANAGEMENT POLICY (continued)

a. Business risks (continued)

The Group's business activities are exposed to a variety of business risks (upstream and downstream) which are as follows: (continued)

iii. The Group is dependent on joint venture partners and third party independent contractors in connection with exploration and production operations and to implement the Group's development programs.
iv. The Group's crude oil, natural gas and geothermal reserves estimates are uncertain and may prove to be inaccurate over time or may not accurately reflect actual reserves levels, or even if accurate, technical limitations may prevent the Group from retrieving these reserves.
v. The Group is dependent on management's ability to develop existing reserves, replace existing reserves and develop additional reserves.
vi. A substantial part of the Group's revenues is derived from sales of subsidised certain fuel (BBM) products by the Government.

b. Financial risk

Financial risk includes market, credit and liquidity risks.

i. Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices.

The market risk factors are as follows:

(i) Foreign exchange risk

Group revenues are determined by the movement of MOPS, which will be paid separately by the public and the Government of Indonesia in the form of subsidised fuel products and LPG products.

Regulations in Indonesia require transactions to be made in Rupiah, while most of the operating costs particularly for the procurement of crude oil and oil products are made in US Dollars, which can lead to foreign exchange risks for cash and cash equivalents, trade receivables, due from the Government, trade payables, short-term loans, due to the Government and long-term liabilities.

The Group naturally mitigates foreign exchange risks through the effective management of its cash flows.

Sensitivity analysis

A strengthening (weakening) of the Rupiah against the US Dollar would have increased (decreased) equity and profit or loss by the amounts shown below. This analysis is based on foreign currency exchange rate variances that were considered to be reasonably possible at the reporting date. The analysis assumes that all other variables, in particular interest rates, remain constant and excludes any impact on forecasted sales and purchases.

	Strengthening		Weakening	
	Equity	Profit or loss	Equity	Profit or loss
March 31, 2019 (unaudited)				
IDR (3% movement)	101,073	96,095	(95,185)	(90,497)
December 31, 2018				
IDR (3% movement)	364,017	358,908	(342,813)	(338,001)
December 31, 2017				
IDR (3% movement)	272,198	267,015	(256,342)	(251,461)
December 31, 2016				
IDR (7% movement)	869,047	866,557	(755,340)	(753,176)

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(ii) Commodity price risk

The volatility in prices of crude oil, natural gas and refined products and the uncertainty of market dynamics for oil and gas could adversely affect the Group's business, financial conditions and results of the Group's operations.

The Group's profitability is significantly affected by the prices of, and demand for, crude oil, natural gas and refined products, the difference between the cost price of crude oil, the costs of exploring for, developing, producing, transporting and selling crude oil, gas and refined products. The international and domestic markets for crude oil and refined products are fluctuative, and have recently been characterized by significant price fluctuations. The fluctuation of the market prices of crude oil, natural gas and refined products is subject to a variety of factors beyond the Group's control.

The Group also participates in physical commodity contracts in the normal course of business. These contracts are not derivatives and are measured at cost. In this case, the Group is not exposed to commodity price risk because the price has been determined at the date of purchase.

(iii) Cash flow and fair value interest risk

The Group is exposed to cash flows and fair value interest rate risk due to its financial assets and liabilities position, mainly to maintain cash flows in order to meet the needs of operational and capital expenditure.

Assets and liabilities with floating rates expose the Group to cash flows interest rate risk. Financial assets and liabilities with fixed rates expose the Group to fair value interest rate risk.

The Group has established a centralised treasury and continuously monitors movements of LIBOR, SIBOR, JIBOR and other borrowing rates prevailing in the market and conducts negotiations to get the most profitable interest rates before making placement of funds or conducts negotiation with lenders if the borrowing rates become uncompetitive compared to prevailing rates in the market.

The Group may use loan facilities provided by national banks such as BNI, BRI, Bank Mandiri, as well as foreign private banks.

At the reporting date, the Group's financial assets and liabilities with floating rates, fixed rates and those that were non-interest bearing were as follows:

	March 31, 2019 (unaudited)					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	3,698,376	-	4,612,308	-	11,426	8,322,110
Restricted cash	28,753	-	80,584	-	-	109,337
Short-term investments	-	-	122,069	-	176,352	298,421
Trade receivables	-	-	-	-	3,724,224	3,724,224
Due from the Government	-	-	-	3,029,233	2,537,673	5,566,906
Other receivables	-	-	-	-	945,222	945,222
Other investments	-	-	-	-	85,089	85,089
Long-term investments	-	391,307	-	23,994	144,206	559,507
Other non-current assets	-	-	-	-	1,186,467	1,186,467
Total financial assets	**3,727,129**	**391,307**	**4,814,961**	**3,053,227**	**8,810,659**	**20,797,283**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

	March 31, 2019 (unaudited)					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Liabilities						
Short-term loans	(3,671,397)	-	-	-	-	(3,671,397)
Trade payables	-	-	-	-	(3,290,095)	(3,290,095)
Due to the Government	-	-	(28,903)	(790,351)	(1,696,790)	(2,516,044)
Accrued expenses	-	-	-	-	(2,115,141)	(2,115,141)
Other payables	-	-	-	-	(362,729)	(362,729)
Long-term liabilities	(369,527)	(1,562,340)	(53,795)	(89,552)	-	(2,075,214)
Bonds payable	-	-	-	(11,099,807)	-	(11,099,807)
Other non-current payables	-	(26,211)	-	-	(62,208)	(88,419)
Total financial liabilities	**(4,040,924)**	**(1,588,551)**	**(82,698)**	**(11,979,710)**	**(7,526,963)**	**(25,218,846)**

	December 31, 2018					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	5,045,495	-	4,062,697	-	4,120	9,112,312
Restricted cash	21,344	-	87,571	-	-	108,915
Short-term investments	677	-	132,430	-	92,092	225,199
Trade receivables	-	-	-	-	3,231,106	3,231,106
Due from the Government	-	-	-	-	4,758,409	4,758,409
Other receivables	-	-	-	-	883,490	883,490
Other investments	-	-	-	-	80,171	80,171
Long-term investments	-	391,307	-	14,989	143,595	549,891
Other non-current assets	-	-	-	-	1,149,976	1,149,976
Total financial assets	**5,067,516**	**391,307**	**4,282,698**	**14,989**	**10,342,959**	**20,099,469**
Liabilities						
Short-term loans	(4,347,035)	-	-	-	-	(4,347,035)
Trade payables	-	-	-	-	(3,676,558)	(3,676,558)
Due to the Government	-	-	(25,247)	(795,082)	(1,182,496)	(2,002,825)
Accrued expenses	-	-	-	-	(1,902,515)	(1,902,515)
Other payables	-	-	-	-	(407,196)	(407,196)
Long-term liabilities	(361,855)	(1,703,996)	(58,722)	(101,304)	-	(2,225,877)
Bonds payable	-	-	-	(11,094,096)	-	(11,094,096)
Other non-current payables	-	-	-	-	(149,428)	(149,428)
Total financial liabilities	**(4,708,890)**	**(1,703,996)**	**(83,969)**	**(11,990,482)**	**(7,318,193)**	**(25,805,530)**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

	December 31, 2017					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	2,770,228	-	3,631,425	-	8,174	6,409,827
Restricted cash	75,243	-	44,428	-	-	119,671
Short-term investments	755	-	150,699	-	97,828	249,282
Trade receivables	-	-	-	-	2,675,643	2,675,643
Due from the Government	-	-	-	-	2,155,739	2,155,739
Other receivables	-	-	-	-	875,514	875,514
Other investments	-	-	-	-	27,328	27,328
Long-term investments	-	391,307	-	20,268	139,291	550,866
Other non-current assets	-	-	-	-	1,292,628	1,292,628
Total financial assets	**2,846,226**	**391,307**	**3,826,552**	**20,268**	**7,272,145**	**14,356,498**
Liabilities						
Short-term loans	(452,879)	-	-	-	-	(452,879)
Trade payables	-	-	-	-	(3,949,398)	(3,949,398)
Due to the Government	-	-	(24,680)	(780,626)	(1,025,939)	(1,831,245)
Accrued expenses	-	-	-	-	(1,759,885)	(1,759,885)
Other payables	-	-	-	-	(467,742)	(467,742)
Long-term liabilities	(315,951)	(1,952,671)	(50,008)	(157,096)	-	(2,475,726)
Bonds payable	-	-	-	(10,385,873)	-	(10,385,873)
Other non-current payables	-	(5,083)	-	-	(64,729)	(69,812)
Total financial liabilities	**(768,830)**	**(1,957,754)**	**(74,688)**	**(11,323,595)**	**(7,267,693)**	**(21,392,560)**

	December 31, 2016					
	Floating rate		Fixed rate			
	Maturity less than one year	Maturity more than one year	Maturity less than one year	Maturity more than one year	Non-interest bearing	Total
Assets						
Cash and cash equivalents	3,011,880	-	3,703,712	-	5,976	6,721,568
Restricted cash	79,537	-	43,160	-	-	122,697
Short-term investments	-	-	70,322	-	60,498	130,820
Trade receivables	-	-	-	-	2,864,720	2,864,720
Due from the Government	-	-	-	-	1,792,457	1,792,457
Other receivables	-	-	-	-	892,637	892,637
Other investments	-	-	-	-	43,190	43,190
Long-term investments	-	391,307	-	21,960	230,733	644,000
Other non-current assets	-	-	-	-	943,178	943,178
Total financial assets	**3,091,417**	**391,307**	**3,817,194**	**21,960**	**6,833,389**	**14,155,267**
Liabilities						
Short-term loans	(230,293)	-	-	-	-	(230,293)
Trade payables	-	-	-	-	(3,409,205)	(3,409,205)
Due to the Government	-	-	(23,538)	(732,573)	(929,007)	(1,685,118)
Accrued expenses	-	-	-	-	(1,473,189)	(1,473,189)
Other payables	-	-	-	-	(269,731)	(269,731)
Long-term liabilities	(671,638)	(2,554,986)	(50,562)	(161,923)	-	(3,439,109)
Bonds payable	-	-	-	(9,772,656)	-	(9,772,656)
Other non-current payables	-	(8,829)	-	-	(47,602)	(56,431)
Total financial liabilities	**(901,931)**	**(2,563,815)**	**(74,100)**	**(10,667,152)**	**(6,128,734)**	**(20,335,732)**

A change of 20 basis points in floating interest rates at the reporting date would have affected income before tax by the amounts shown below. This analysis assumed that all other variables, in particular foreign currency rates, remain constant.

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

i. Market risk (continued)

(iii) Cash flow and fair value interest risk (continued)

Effect in:	+20 bp increase	-20 bp decrease
Income before tax	(2,969)	2,969
Cash flows sensitivity - net	**(2,969)**	**2,969**

ii. Credit risk

The Group has significant credit risk from unpaid receivables, cash and cash equivalents and investments in debt securities. In most transactions, the Group uses banks and financial institutions that are independently assessed with a rating of AAA, AA+, AA, AA-, A+, A and A-.

For the Group's credit sales, the Group applied a standard operating procedure for credit approval mechanism. With such practice, some portion of the Group's credit sales has been secured with a collateral/bank guarantee. For other credit sales without collateral/bank guarantee, the Group ensured that credit scoring, credit limit evaluation and credit approval were performed and provided prior to any sales to the customer.

The Group also has a Credit Management System to monitor the usage of credit limits and automatic blocking facility in the case of no payment starting from seven days after the maturity date. The Group will impose penalty for overdue payments in some sales contracts based on the result of each customer's credit evaluation.

(i) Third parties and related parties

Financial assets neither past due nor impaired

The credit quality of the Group's financial assets that are neither past due nor impaired, was assessed by referencing external credit ratings PT Pemeringkat Efek Indonesia ("Pefindo") or to historical information about counterparty default risk rates, as follows:

	As of March 31, 2019 (unadited)	December 31, 2018	December 31, 2017	December 31, 2016
Cash and cash equivalents				
Rated				
Rating AAA	6,907,823	7,285,583	5,654,815	6,179,970
Rating AA+	803,567	1,139,349	426,347	313,456
Rating AA	50,160	50,028	26,770	7,613
Rating AA-	2,359	3,528	2,581	35,090
Rating A+	1,404	1,381	31,699	14,714
Rating A	12,234	20,380	147,282	78,117
Rating A-	26,743	21,472	-	-
Not rated	517,820	590,591	120,333	92,608
Total	**8,322,110**	**9,112,312**	**6,409,827**	**6,721,568**
Restricted cash				
Rated				
Rating AAA	104,100	104,230	107,688	114,855
Rating A+	-	-	5	7,615
Rating A	-	-	224	227
Rating A-	462	462	-	-
Not rated	4,775	4,223	11,754	-
Total	**109,337**	**108,915**	**119,671**	**122,697**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets neither past due nor impaired (continued)

The credit quality of the Group's financial assets that are neither past due nor impaired, was assessed by referencing external credit ratings PT Pemeringkat Efek Indonesia ("Pefindo") or to historical information about counterparty default risk rates, as follows: (continued)

	As of March 31, 2019 (unaudited)	December 31, 2018	December 31, 2017	December 31, 2016
Short-term investments				
Rated				
Rating AAA	37,659	25,332	19,022	22,358
Rating AA+	1,390	1,027	1,145	1,799
Rating AA	4,203	4,109	10,108	11,669
Rating AA-	3,178	3,129	3,085	4,964
Rating A	5,527	5,357	3,522	-
Rating A-	2,345	2,330	749	-
Rating BB+	-	-	-	5,195
Rating BBB+	-	-	1,870	1,635
Rating BBB	3,887	3,887	-	-
Rating BBB-	29,936	41,948	44,149	34,816
Not rated	210,296	138,080	165,632	48,384
Total	**298,421**	**225,199**	**249,282**	**130,820**
Long-term investments				
Rated				
Rating AAA	536	2,597	7,198	8,873
Rating AA	5,991	5,897	6,320	8,847
Rating BBB-	4,950	4,950	4,950	-
Rating BB+	-	-	-	2,000
Not rated	11,588	552	221	186
Total	**23,065**	**13,996**	**18,689**	**19,906**
Trade receivables				
Third parties				
> US$10,000 - Good credit history	1,589,891	1,335,703	945,008	850,886
< US$10,000	912	362	726	9,909
Related parties	626,615	675,922	251,453	394,209
Total	**2,217,418**	**2,011,987**	**1,197,187**	**1,255,004**
Other receivables				
Third parties				
> US$10,000 – good credit histories	741,118	661,979	570,683	582,970
< US$10,000	70	31	82	130
Related parties	165,072	148,777	253,389	236,205
Total	**906,260**	**810,787**	**824,154**	**819,305**
Other assets				
Third parties	86,568	80,287	80,349	135,481
Related parties	32,746	54,228	152,791	82,166
Total	**119,314**	**134,515**	**233,140**	**217,647**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets that are past due but not impaired

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables				
- Less than 3 months	589,193	431,868	227,439	365,007
- 3 - 6 months	119,033	61,194	212,778	30,820
- 6 - 12 months	34,967	21,138	10,231	34,955
- 12 - 24 months	6,858	11,040	1,201	36,788
- > 24 months	7,511	11,561	2,194	2,499
Total	**757,562**	**536,801**	**453,843**	**470,069**
Other receivables				
- Less than 3 months	2,516	42,912	31,832	3,904
- 3 - 6 months	658	1,699	642	27,182
- 6 - 12 months	785	872	160	3,947
- 12 - 24 months	908	10,674	524	6,695
- > 24 months	5,135	5,476	921	3,669
Total	**10,002**	**61,633**	**34,079**	**45,397**
Related parties				
- Less than 3 months	8	9	141	391
- 3 - 6 months	11	7	2	-
- 6 - 12 months	30	49	1,332	24
- 12 - 24 months	21	15	68	-
- > 24 months	21	24	11	6,215
Total	**91**	**104**	**1,554**	**6,630**
Other assets				
Third parties	-	-	90,995	-
Related parties	11,152	10,679	-	4,066
Total	**11,152**	**10,679**	**90,995**	**4,066**

Trade receivables

Trade receivables from third parties and related parties that are past due but not impaired at the reporting date relate to customers who have not had defaults in the past two years. Some of the trade receivables from these customers have also been secured with collateral/bank guarantee.

Financial assets that are impaired

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Trade receivables				
- Current (not overdue)	351,615	453,510	731,355	345,402
- Less than 3 months	236,196	182,954	179,382	422,487
- 3 - 6 months	137,956	70,803	81,009	41,370
- 6 - 12 months	80,277	10,541	26,250	8,647
- 12 - 24 months	41,402	45,159	69,412	466,339
- > 24 months	147,079	180,082	195,558	165,566
	994,525	943,049	1,282,966	1,449,811
Impairment	(245,281)	(260,731)	(258,353)	(310,164)
Net	**749,244**	**682,318**	**1,024,613**	**1,139,647**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(i) Third parties and related parties (continued)

Financial assets that are impaired (continued)

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
Other receivables				
Related parties				
- Less than 3 months	20	-	110	31
- 3 - 6 months	-	-	31	3
- 6 - 12 months	5	297	1	-
- 12 - 24 months	28	-	1	-
- > 24 months	1,400	1,426	1,434	1,403
	1,453	**1,723**	**1,577**	**1,437**
Third parties				
- Less than 3 months	29,971	6,169	5,651	13,383
- 3 - 6 months	717	673	4,613	751
- 6 - 12 months	402	975	6,734	2,163
- 12 - 24 months	7,728	8,362	4,112	8,048
- > 24 months	11,985	12,631	13,057	8,591
	50,803	**28,810**	**34,167**	**32,936**
	52,256	30,533	35,744	34,373
Impairment	(23,387)	(19,567)	(20,017)	(13,068)
Net	**28,869**	**10,966**	**15,727**	**21,305**
Other assets				
Related parties				
- 12 - 24 months	-	-	-	-
- > 24 months	18,481	18,190	19,394	19,550
Third parties				
- Current (not overdue)	1,701	-	-	-
- 12 - 24 months	5,352	9,165	-	1,469
- > 24 months	-	-	17,023	20,707
	25,534	27,355	36,417	41,726
Impairment	(25,534)	(27,355)	(36,417)	(41,726)
Net	**-**	**-**	**-**	**-**

Trade receivables

Trade trade receivables from third parties and related parties as of March 31, 2019 amounting to US$3,969,505 has been impaired amounting to US$245,281, with the largest trade receivables from Government institutions and MoSOE, which is TNI/Kemhan amounting to US$433,760.

Other receivables

Other receivables from third parties and related parties as of March 31, 2019 US$927,042 have been impaired by US$18,180.

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

ii. Credit risk (continued)

(ii) Government

Financial assets neither past due not impaired

	March 31, 2019 (unaudited)	December 31, 2018	2017	2016
The Company				
Receivables on revenue recognition from Disparity of Selling Price	3,029,233	2,924,148	-	-
Receivable of reimbursements of Subsidy costs for LPG 3 kg cylinders	1,471,665	1,147,538	1,404,911	1,068,920
Receivable of subsidy reimbursements for certain fuel (BBM) products	368,762	175,556	473,928	422,398
Receivables for marketing fees	77,179	72,489	49,902	-
Receivables from kerosene subsidies reimbursement	17,108	16,828	-	-
Kerosene conversion	10,767	10,626	-	-
Other receivables	-	-	102	14
Sub total	**4,974,714**	**4,347,185**	**1,928,843**	**1,491,332**
Subsidiaries:				
PEP				
- DMO fees	106,928	106,398	90,930	77,340
- Underfifting	-	18,942	-	-
PHE				
- DMO fees	18,357	15,414	25,859	25,613
- Underlifting	21,860	25,730	46,480	31,395
PEPC				
- Underlifting	423,189	224,904	174,563	79,966
PHI				
- DMO Fees	21,858	18,780	-	-
- Underlifting	-	1,056	-	-
Sub total	**592,192**	**411,224**	**337,832**	**214,314**
Total	**5,566,906**	**4,758,409**	**2,266,675**	**1,705,646**
Financial assets that are impaired				
The Company				
Receivables for marketing fees	-	-	-	86,811
Provision for impairment	-	-	(110,936)	-
	-	-	(110,936)	86,811
Total consolidated	**5,566,906**	**4,758,409**	**2,155,739**	**1,792,457**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

iii. Liquidity risk

The amount of liquidity which the Group requires for its operations is uncertain and its operations may be adversely affected if the Group does not have sufficient working capital to meet its cash and operational requirements. This may occur as a result of, amongst other reasons, delays in the payment of the Government's subsidies.

The Group uses significant amounts of cash in its operations, especially to procure commodities and raw materials. In particular, one of its principal operating costs is the acquisition of feedstock for its refineries. Fluctuations in market prices for crude oil, natural gas and their refined products and fluctuations in exchange rates cause working capital and costs for the Group's upstream and downstream operations to be uncertain.

The Group funds its operations principally through cash flows from operations, a significant portion of which comprises sales, subsidy payments, working capital facilities (including bank overdrafts, L/C and revolving credit), and long-term bank loans. In accordance with the terms of PSO's assignment, the Group is required to submit its claims for subsidy to the Government at the end of each month for the subsidised fuel distributed in that month.

As of March 31, 2019, and December 31, 2018, 2017, and 2016 the Group has cash and cash equivalents in the amount of US$8,322,110, US$9,112,312, US$6,409,827, and US$6,721,568 respectively (Note 6). The Group manages liquidity risk by continuously monitoring forecasts and actual cash flows and matching the maturity profiles of trade receivables and trade payables.

The table below summarizes the maturity profile of the Group's financial liabilities based on cash flow on contractual undiscounted payments:

	Less than 1 year	Later than 1 year and not later than 5 years	Later than 5 years	Total
March 31, 2019 (unaudited)				
Financial liabilities				
Short-term loans	3,671,397	-	-	3,671,397
Trade payables	3,290,095	-	-	3,290,095
Due to the Government	1,726,190	328,225	603,899	2,658,314
Accrued expenses	2,115,141	-	-	2,115,141
Other payables	1,468,529	-	-	1,468,529
Long-term liabilities	456,479	1,384,798	334,151	2,175,428
Bonds payable	611,409	5,888,039	14,088,112	20,587,560
Other non-current payables	-	78,524	39,600	118,124
Total financial liabilities	**13,339,240**	**7,679,586**	**15,065,762**	**36,084,588**

48. RISK MANAGEMENT POLICY (continued)

b. Financial risk (continued)

iii. Liquidity risk (continued)

	Less than 1 year	Later than 1 year and not later than 5 years	Later than 5 years	Total
December 31, 2018				
Financial liabilities				
Short-term loans	4,347,035	-	-	4,347,035
Trade payables	3,676,558	-	-	3,676,558
Due to the Government	1,211,056	262,428	531,845	2,005,329
Accrued expenses	1,902,515	-	-	1,902,515
Other payables	1,257,437	-	-	1,257,437
Long-term liabilities	456,506	1,530,224	343,001	2,329,731
Bonds payable	611,409	5,886,768	14,088,112	20,586,289
Other non-current payables	-	120,591	58,314	178,905
Total financial liabilities	**13,462,516**	**7,800,011**	**15,021,272**	**36,283,799**
December 31, 2017				
Financial liabilities				
Short-term loans	452,879	-	-	452,879
Trade payables	3,949,398	-	-	3,949,398
Due to the Government	1,138,463	255,460	437,644	1,831,567
Accrued expenses	1,759,885	-	-	1,759,885
Other payables	1,178,119	-	-	1,178,119
Long-term liabilities	394,188	1,293,419	844,763	2,532,370
Bonds payable	575,969	4,625,314	14,773,197	19,974,480
Other non-current payables	-	84,373	-	84,373
Total financial liabilities	**9,448,901**	**6,258,566**	**16,055,604**	**31,763,071**
December 31, 2016				
Financial liabilities				
Short-term loans	230,293	-	-	230,293
Trade payables	3,409,205	-	-	3,409,205
Due to the Government	1,194,559	5,886	488,804	1,689,249
Accrued expenses	1,473,189	-	-	1,473,189
Other payables	1,077,755	-	-	1,077,755
Long-term liabilities	887,736	2,144,421	585,919	3,618,076
Bonds payable	490,969	3,235,755	15,643,533	19,370,257
Other non-current payables	-	62,903	-	62,903
Total financial liabilities	**8,763,706**	**5,448,965**	**16,718,256**	**30,930,927**

c. Capital management

The Directors' policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. Capital consists of share capital, retained earnings, non-controlling interests and other equity components. The Board of Directors ensures the return on capital as well as the level of dividends.

The Group as an entity whose main business involves oil and gas monitors capital on the basis of the debt-to-equity ratio. Net debt is calculated as total interest bearing borrowings including short-term and long-term, while total capital is calculated from equity in the consolidated statement of financial position. Weighted average interest expense on interest-bearing borrowings (excluding liabilities with imputed interest) for March 31, 2019 and December 31, 2018, 2017, and 2016 were 5.35%, and 5.17%, 4.92% and 4.68%.

48. RISK MANAGEMENT POLICY (continued)

c. Capital management (continued)

The Group's debt to equity ratio at the reporting date is as follows:

	March 31, 2019 (unaudited)	December 31,		
		2018	2017	2016
Total liabilities (interest bearing)	17,665,671	18,487,337	13,707,878	13,775,548
Total equity attributable to owners of the parent	27,718,913	27,598,721	25,124,718	23,665,987
Debt-to-equity ratio	63.73%	66.99%	54.56%	58.21%
Total own capital to total assets ratio	39.77%	40.31%	37.85%	36.82%
Return-on-equity ratio	2.10%	10.08%	12.62%	17.74%

d. Fair value

The following are the Group's financial assets that were measured at fair value as of March 31, 2019 (unaudited):

	Level 1	Level 2	Level 3	Total
Financial assets				
Short-term investments	248,729	48,999	693	298,421
Other investments - net	-	-	85,089	85,089
Total financial assets	**248,729**	**48,999**	**85,782**	**383,510**

As of March 31, 2019, there were no transfers of fair value measurement between level 1, level 2 and level 3.

The table below shows the carrying amounts and fair values of long-term financial liabilities as of March 31, 2019, and December 31, 2018, 2017, and 2016:

	March 31, 2019 (unaudited)	
	Carrying Amount	Fair Value
Long-term liabilities (Note 20)	2,075,214	2,159,257
Bonds payable (Note 21)	11,099,807	11,757,624
Total financial assets	**13,175,021**	**13,916,881**

	December 31,					
	Carrying Amount			Fair Value		
	2018	2017	2016	2018	2017	2016
Long-term liabilities (Note 20)	2,225,877	2,475,726	3,439,109	2,329,464	2,478,169	3,653,966
Bonds payable (Note 21)	11,094,096	10,385,873	9,772,656	11,101,427	11,504,854	9,849,462
Total financial assets	**13,319,973**	**12,861,599**	**13,211,765**	**13,430,891**	**13,983,023**	**13,503,428**

The fair value of long-term liabilities is measured using the discounted cash flows based on the interest rate on the latest long-term liabilities of the Group. The fair value of bonds payable is determined by reference to market price at the reporting date.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES

a. Cooperation contract commitment

In accordance with the Cooperation Contract, PT Pertamina EP shall relinquish minimum of 10% of the original contract area to the Government on or before the end of the tenth year from the effective date of the Cooperation Contract. On July 18, 2013, PT Pertamina EP relinquished 18.02% of initial working area to the Government.

PT Pertamina EP is required to pay a bonus to the Government amounting to US$1,500 in 30 days after cumulative production of oil and gas reaches 1,500 MMBOE from the effective date of the Cooperation Contract. PT Pertamina EP's cumulative production of oil and gas up to March 31, 2019 has not yet reached 1,500 MMBOE.

On March 31, 2019, PT Pertamina Hulu Energi had 15 exploration commitments in relation to PSC profit sharing contracts with commitments between US$11,750 to US$225,000 and 10 exploration commitments in relation to the Gross Split contract with a commitment amounting to US$15,550 to US$239,300.

PT Pertamina Hulu Indonesia has expenditure commitments and work plans with a commitment value between US$141,300 to US$703,000 with a period of six years from the effective date of the contract.

b. Capital commitments

The Group has capital expenditure commitments in the normal course of business. As of March 31, 2019, the Group's unrealized total outstanding capital expenditure commitments amounting to US$3,709,372.

c. Operating lease commitments - Group as lessee

Non-cancellable operating lease payments are as follows:

	For the three-month periods ended March 31,		For the years ended December 31,		
	2019 (unaudited)	2018 (unaudited)	2018	2017	2016
Less than one year	498,788	528,514	493,867	465,882	375,333
Between one to five years	557,713	624,907	559,313	571,611	525,309
More than five years	65,289	24,160	33,284	24,160	-
Total	**1,121,790**	**1,177,581**	**1,086,464**	**1,061,653**	**900,642**

The Group leases a number of vessels, office buildings, vehicles and IT facilities under operating leases. The leases typically run for a period of ten years, with an option to renew the lease.

Operating lease expense for three-months periods ended March 31, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016, was US$182,704 (unaudited), US$64,766 (unaudited), US$343,868, US$782,362 and US$796,897 respectively.

d. Gas sale and purchase agreement

As of March 31, 2019, the Company through PT Pertamina EP has commitments to deliver gas amounting to 705,508 MMSCF to various customers. The gas will be periodically delivered from 2017 until 2029.

As of March 31, 2019, the Company, through PHE, has various significant gas supply agreements with various customers, with gas value of each contract between 0.8 TBTU to 1.418 TBTU. The expiration of these agreements ranges from 2019 until 2031.

As of March 31, 2019, the Company, through PHI, has significant gas sale and purchase agreement contracts with gas volumes of 0.8 TBTU up to 183.13 TBTU. These contracts will expire in 2018 to 2022.

As of March 31, 2019, the Company, through PGN has 39 Gas Sales and Purchase Agreements ("GSA") with working areas in Sumatera, Java and Kalimantan with contract periods of 10 - 30 years. The effective year of the agreement ranges from 1999 to 2019 and the year ends of the agreement ranges from 2019 to 2037.

Based on Indonesian Presidential Regulation No. 40 year 2016 on Natural Gas Pricing and Regulation of the Minister of Energy and Mineral Resources of the Republic of Indonesia No. 40 year 2016 on Natural Gas Price for Specific Industries, the Company amended contract gas prices decline in gas sales agreements with the particular industry effective January 30, 2017.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

e. LNG Long-term purchase contract commitment

The Company entered into a LNG Long Term Purchase Contract with several sellers for LNG trading business, with minimum purchase quantity per annum of each contract between 0.1 million MT to 1.5 million MT, with purchase price that linked to the related market price at the time of delivery of LNG. The term of those contracts ranges from 2018 until 2044.

f. Transfer of 10% participating interest ("PI") to the regional government ("BUMD")

ONWJ Block PSC

On December 19, 2017, PHE ONWJ and MUJ ONWJ signed a 10% PI transfer agreement at Blok ONWJ PSC from PHE ONWJ to MUJ ONWJ. The agreement is effective on the date of receipt of approval from the Minister of Energy and Mineral Resources or on the date stipulated by the Minister of Energy and Mineral Resources in his approval letter.

On May 17, 2018, the approval 10% of PI transfer in the ONWJ working area has been approved by the Minister of Energy and Mineral Resources through a Letter from the Minister of Energy and Mineral Resources to the Head of SKK Migas No. 2803/13/MEM.M/2018. Stated in the letter, the date of the transfer of PHE ONWJ to MUJ ONWJ is from the effective date of the Block ONWJ PSC.

On December 17, 2018, the PI transfer value was determined through a Letter from the Minister of Energy and Mineral Resources to the Head of SKK Migas No. 3149/12/MEM.M/2018. The transfer value is calculated from the BUMD's liability for the portion of the implementation guarantee (Performance Bond) for the implementation of a definite work commitment and the portion of the unrecovered cost payment by the new KKS Contractor to the old KKS Contractor with a value of US$43,292.

As discussed in Note 4k, PHE ONWJ and MUJ ONWJ have signed an addendum on the transfer agreement and management of 10% at ONWJ PSC. Where the accumulation of net profit-sharing and liability of a 10% PI transfer MUJ ONWJ from January 19, 2017 to December 31, 2018 is US$ 16,302,702 (full amount). Settlement of such obligations was completed on February 8, 2019.

SIAK PSC

On August 7, 2018, PHE Siak and PT Riau Petroleum Siak agreed to sign an agreement to transfer and operate a 10% participating interest in accordance with Regulation of the Minister of Energy and Mineral Resources of the Republic of Indonesia No.37 year 2016 on Offering Terms of 10% PI in Oil and Gas Block.

g. Legal case

i. PT Golden Spike Energy Indonesia ("GSEI") lawsuit

PT Golden Spike Energy Indonesia ("GSEI") and PT Pertamina Hulu Energi Raja Tempirai ("PHE RT") are holders of 50% participating interests each in the Raja Block PSC.

On April 5, 2013, GSEI submitted a civil lawsuit against PHE RT in the Central Jakarta District Court on the basis that operations conducted during the exploration period were GSEI's Sole Risk Operations and therefore only GSEI was entitled to receive compensation.

The court, objection, cessation and arbitration processes have been finalized. On February 17, 2017, the ICC Arbitration has issued the third and final award which decided the case in favor of PHE RT.

Such ICC's third and final award has been registered and received by the Central Jakarta District Court based on the Deed No. 02/Pdt/Arb-Int/2017/PN.Jkt.Pst dated June 14, 2017.

Furthermore, to execute the Third and Final Award above, PHE RT has submitted an executive application to the Central Jakarta District Court on December 13, 2017 and has been responded in 2018.

As of the completion date of these consolidated financial statements, PHE RT is in the process of 'aanmaning' to the Central Jakarta District Court.

49. SIGNIFICANT AGREEMENTS, COMMITMENTS AND CONTINGENCIES (continued)

g. Legal Case (continued)

ii. PT Bakrie Harper Corporation lawsuit

On November 20, 1996, the Company entered into a Build and Rent Agreement in the form of Development, Operation, Lease and Maintenance of Piping Kertapati-Jambi ("Pipeline Project Work") No.SPB-1474A/C000/96 with PT Bakrie Harper (formerly PT Bakrie Harper Corporation - "Bakrie"). Total Pipeline Project Work Value and Rental fee was US$144,068 and US$16,703 (excluding VAT), respectively. The lease term for such project is 10 years with commencement date of the project development on May 19, 1997.

Due to the monetary crisis in 1998, the Company delay the Pipeline Project Work and renegotiated the project value. In 2001, both parties agreed to appoint Deloitte Touche ("Deloitte") as an independent party to audit fair market costs of the Pipeline Project Works. Based on the Deloitte audit report issued in 2001, fair market costs and rental costs were US$92,125 and US$7,616 respectively.

On August 27, 2002, the Company appointed the BPKP to perform due diligence to obtain the fair market value of the costs incurred by Bakrie for such project from commencement date of through the date when the project development ceased. Based on the BPKP's report issued on December 23, 2003, it is noted that the physical progress of the Pipeline Project Work was 10.6853% with a fair value of US$15,394 exclude the compensation for investment costs incurred. BPKP also noted that the Pipeline Project Work is no longer economics and feasible to continue.

On June 9, 2017, both parties agreed to settle the case through the Indonesian National Arbitration Board ("BANI"). The amount claimed by Bakrie is US$15,394 for physical progress work and US$17,307 for 14 years of interest. Based on BANI decision No. 969/VIII/ARB-BANI/2017 dated February 21, 2018, it is noted that the Pipeline Project Work agreement is already expired, the physical progress of the Pipeline Project Work is 10.6853% and the Company should pay to Bakrie the amount of US$15,856, which consists of compensation and total interest to Bakrie amounting to US$15,394 and US$462, respectively.

On April 16, 2018, the Company appointed the Attorney General's Office of the Republic of Indonesia ("Jamdatun") to provide legal assistance and to propose Legal action related to BANI decision. The Company is willing to settle BANI decision with condition that the payment made by the Company is based on BPK report and should be supported by adequate documents, including land rights with value equal to the payment will be made by the Company. The cancellation claim has been submitted by Jamdatun through the Central Jakarta District Court but was refused. Based on the advice of the State Attorney, in the event that Bakrie submitted an attempt to execute the BANI verdict, the Company has the option to file a lawsuit against the execution.

h. Onerous contract

The Public Service Obligation ("PSO") assignment to supply fuel products

The Company has a relationship with the Government for the assignment of PSO to supply certain fuel products. The Company and the Government agreed to use Mean of Platts Singapore ("MOPS") as the basis for the market price of fuel projects use to calculate the amount of subsidies. However, the retail selling price of certain fuel products issued by the Ministry of Energy and Mineral Resources during 2017 and 2018 cannot cover all costs for procuring and distributing fuel products which resulted losses from the sale of PSO fuel products for the three-month periods ended March 31, 2019 and 2018, and for the years ended December 31, 2018, 2017, and 2016.

i. Reimbursement of investment costs to previous PSC contractors

The regulation of the Minister of Energy and Mineral Resources No. 26/2017, No. 47/2017, No. 24/2018 and No. 46/2018 require new PSC contractors to reimburse certain investment costs spent by the previous PSC contractors which have not been recovered at the time the PSC expired. The amount to be reimbursed is based on verification and approval from SKK Migas. Based on letter SRT-0665/SKKMA0000/2018/S4 dated August 13, 2018 from SKK Migas, the amount to be reimbursed by Pertamina Hulu Sanga-Sanga (PHSS) to the previous Sanga-Sanga PSC contractors amount to US$111.9 million. PHSS disagree with the amount and is in the process of obtaining assistance from the relevant institution to verify the amount to be paid. As of March 31, 2019, the amount of investment costs to be reimbursed to the previous Sanga-Sanga PSC contractors has not been recognized.

50. EVENTS AFTER THE REPORTING PERIOD

a. Changes in the composition of the Board of Commissioners

Based on the decision of the GMS No. SK-86/MBU/04/2019 dated April 30, 2019, Gatot Trihargo has been appointed as the new Commissioner of the Company. Based on the same GMS decision, Sahala Lumban Gaol and Ahmad Bambang were honorably dismissed from their respective positions as the Company's Board of Commissioners. Thus, the composition of the Board of Commissioners is as follows:

President Commissioner	Tanri Abeng
Vice President Commissioner	Arcandra Tahar
Commissioner	Alexander Lay
Commissioner	Ego Syahrial
Commissioner	Gatot Trihargo
Commissioner	Suahasil Nazara

b. PCS gross split Rokan Block

The Rokan Block PSC agreement was signed on May 9, 2019 between SKK Migas and PHR for a period of 20 years. The PSC contract lays out the production sharing split for both crude oil and natural gas. For both crude oil and natural gas, the PSC contract uses the gross split concept with an additional discretion of 8%.

For crude oil, this results in a 65% contractor and 35% government split for Duri working area fields, and a split of 61% contractor and 39% government split for Non-Duri working area fields.

For natural gas production split, the split is 70% contractor and 30% government for Duri working area fields, and a split of 66% contractor and 34% government for Non-Duri working area fields.

c. Tax Administration Charge Annulment

On April 9, 2019, the Company obtained from DGT decision number KEP-00297/NKEB/WPJ.19/2019 regarding the write-off STP VAT penalties for fiscal year 2016 amounted Rp400.93 billion (equivalent to US$28,147) (Note 40a).

d. General Meeting of Shareholders (“GMS”)

On May 31, 2019, the Company held GMS for fiscal year 2018. Based on minutes of meeting, the shareholders approved, among other things, the utilization of 2018 net income of the Company to be as follows:

- Distribution of dividends amounting to Rp7.95 trillion (equivalent to US$558,043).
- The remaining amount of US$1,968,729 as reserve to support operations and corporate development.

e. Trustee Borrowing Structure Mechanism (“TBS”)

On June 13, 2019, PEPC through a TBS obtained the following financing facilities for JTB project development with a total facility of US$1,846,400:

- Jambaran-Tiung Biru Loan Agreement, which was signed by the Trustee, MUFG Bank Ltd. as Agent and Lenders, with a total facility of US$700,000 from Tranche A and US$1,046,400 from Tranche B. The loan bears interest at a rate of LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B.
- Jambaran-Tiung Biru Wakala Agreement, which was signed by the Trustee and MUFG Bank (Malaysia) Berhad as Investment Agent, with a total facility of US$40,000 from Tranche A and US$60,000 from Tranche B. The loan bears interest at a rate of LIBOR + applicable margin of 2.95% for Tranche A and LIBOR + applicable margin of 2.15% for Tranche B.

The Tranche A loan principal is repayable on a semi-annual basis with the first payment due on March 31, 2022 and the final payment due on March 31, 2034. The Tranche B loan principal is repayable on a semi-annual basis with the first payment due on March 31, 2022 and the final payment due on March 31, 2029. There has been no drawdown made through the date of this financial statements.

ISSUER

PT Pertamina (Persero)
Jl. Medan Merdeka Timur 1A
Jakarta 10110, Indonesia

ARRANGERS & DEALERS

Deutsche Bank AG,
Singapore Branch
One Raffles Quay
#17-00 South Tower
Singapore 048583

The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch
21 Collyer Quay
#10-01 HSBC Building
Singapore 049320

Mandiri Securities Pte. Ltd.
12 Marina View, #19-06
Asia Square Tower 2
Singapore 018961

Standard Chartered Bank
One Basinghall Avenue
London EC2V 5DD
United Kingdom

LEGAL ADVISORS

To the Issuer as to

New York and U.S. federal securities law:

Latham & Watkins LLP
9 Raffles Place
#42-02 Republic Plaza
Singapore 048619

Indonesian law:

UMBRA Partnership
Telkom Landmark Tower 49/F
Jl. Gatot Subroto Kav. 52-53
Indonesia 12710

To the Arrangers and the Dealers as to

New York and U.S. federal securities law:

Allen & Overy LLP
50 Collyer Quay
#09-01 OUE Bayfront
Singapore 049321

Indonesian law:

Ginting & Reksodiputro in association with Allen & Overy LLP
The Energy Building, 15th Floor
Sudirman Central Business District
Jl Jend Sudirman Kav 52-53
Jakarta 12190, Indonesia

INDEPENDENT PUBLIC ACCOUNTANTS

KAP Purwantono, Sungkoro & Surja
(the Indonesian member firm of Ernst & Young Global Limited)
Indonesia Stock Exchange Building
Tower 2, 7th Floor
Jl. Jend. Sudirman Kav. 52-53
Jakarta 12190, Indonesia

PAYING AGENT

The Bank of New York Mellon, London Branch
One Canada Square London E14
5AL United Kingdom

TRUSTEE, REGISTRAR, TRANSFER AGENT AND PAYING AGENT

The Bank of New York Mellon
240 Greenwich Street
New York, New York 10286
United States of America

EURO REGISTRAR

The Bank of New York Mellon SA/NV, Luxembourg Branch
Vertigo Building-Polaris
2-4 rue Eugene Ruppert
L-2453 Luxembourg



PT PERTAMINA (PERSERO)

(a state-owned company incorporated in the Republic of Indonesia with limited liability)

US$10,000,000,000

Global Medium Term Note Program

OFFERING MEMORANDUM

Arrangers & Dealers

Deutsche Bank **HSBC** **Mandiri Securities** **Standard Chartered Bank**

July 23, 2019