

KRISENERGY

ANNUAL REPORT 2014

DISCOVERING HIDDEN VALUE









Established in 2009 by a management team with decades of experience and a proven track record, KrisEnergy Ltd was borne from a vision to build a sustainable and best-in-class upstream oil and gas company focused on high-potential geological basins in Southeast Asia.

Today, KrisEnergy's portfolio comprises 19 contract areas across various stages of exploration, appraisal, development and production. Our geographical focus area stretches from the Surma Basin in Bangladesh in the west to the Papuan Basin in the east, and from offshore southern China in the north to Indonesia in the south.

These early years mark only the beginning of KrisEnergy's evolution. New oil and gas projects scheduled to come on stream from 2015 onwards will increase reserves, production and cash flow, and a series of exploration wells in the coming years has the potential to be transformational. Business development activities run in parallel with operations and provide organic growth as well as M&A opportunities.

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GROWING A SUSTAINABLE E&P COMPANY

From a commitment of private equity seed capital in 2009, KrisEnergy has evolved into a full life-cycle E&P company with a diverse portfolio of exploration, appraisal, development and production assets.

Our roots are in exploration, which feeds organic growth. All of our assets contain prospects and leads with upside resource potential.

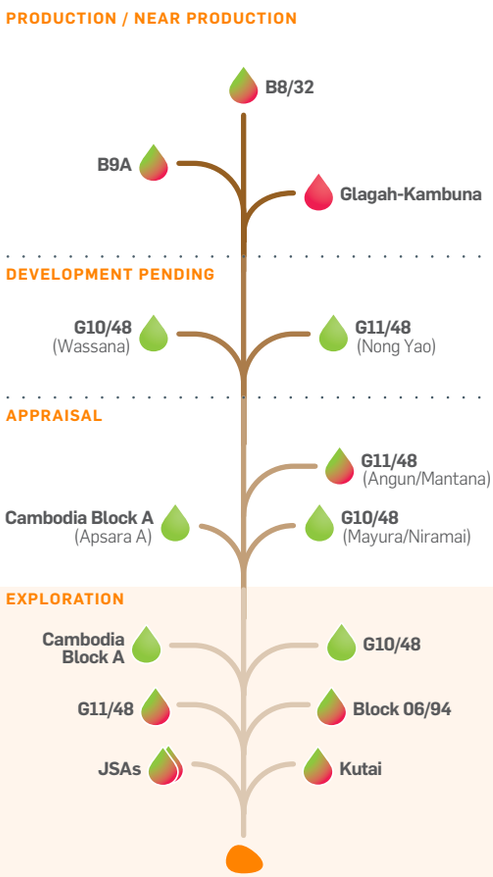
Successful appraisal of oil or gas discoveries may result in development under the appropriate commercial environment.

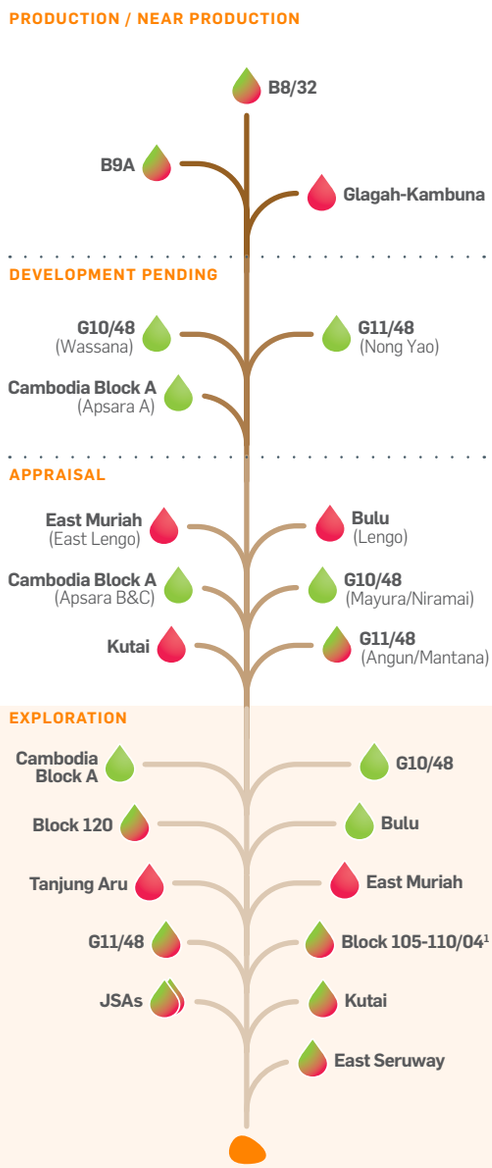
Flourishing production provides cash flow to fund exploration and appraisal activities.

We aggressively seek new acquisition opportunities across the E&P cycle but remain committed to maintaining rigorous selection standards. Likewise, the divestment of assets is also critical to portfolio management.

We continually review our financing and capital structure to maintain a robust balance sheet that will support growth.







FINANCING

2009

- Established KrisEnergy with up to US$500 mm funding from First Reserve
- US$301 mm maximum drawdown

2010

- Entered into US$150 mm M&A facility

2011

- Issued US$85 mm senior guaranteed secured bonds @ 10.5% ("2016 Notes")
- Repaid US$150 mm M&A facility
- Secured US$30 mm revolving credit facility ("RCF")

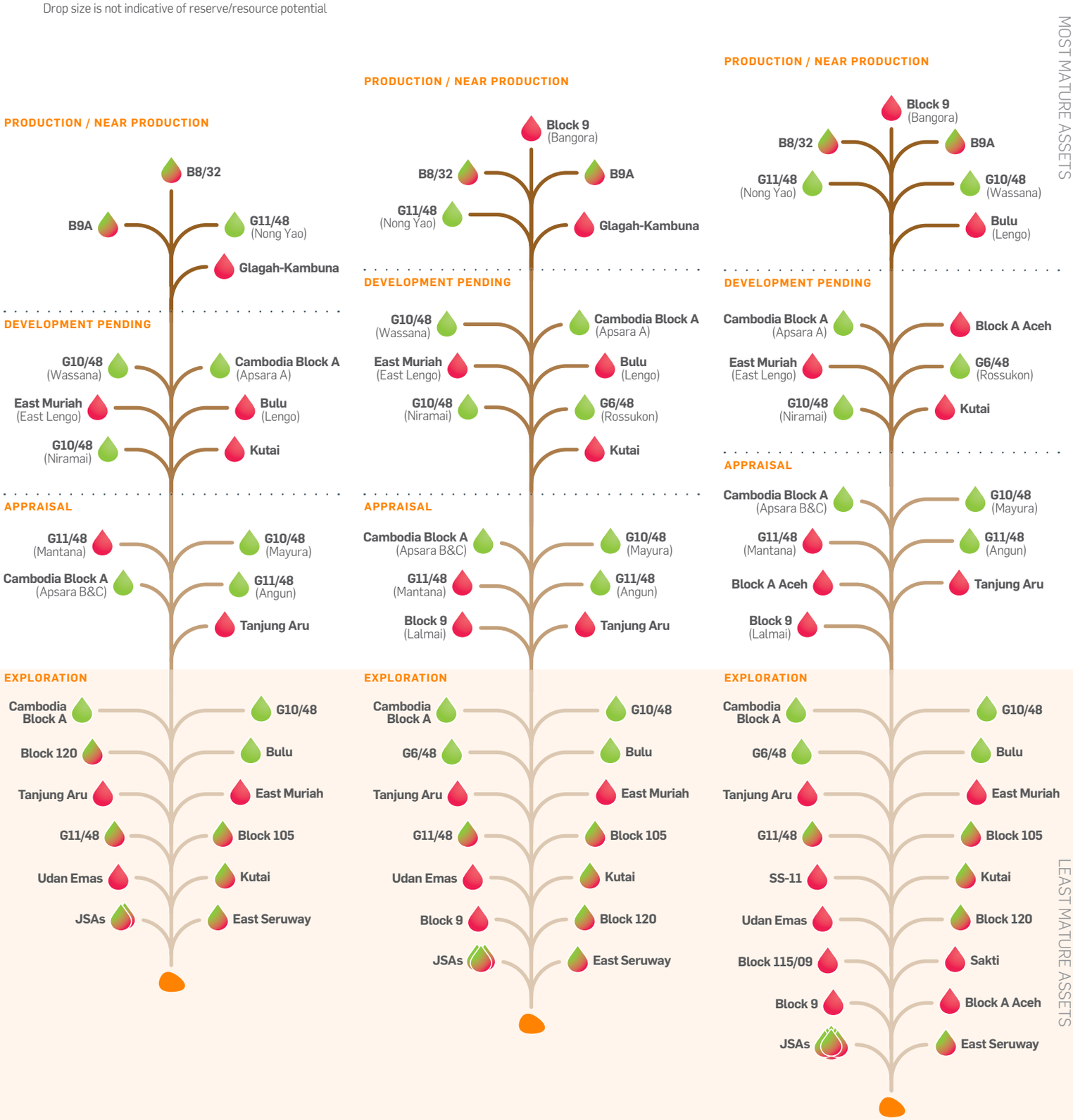
[1] Block 105-110/04 is defined as Block 105

Oil Gas Oil & Gas

Drop size is not indicative of reserve/resource potential

MOST MATURE ASSETS

LEAST MATURE ASSETS



2012

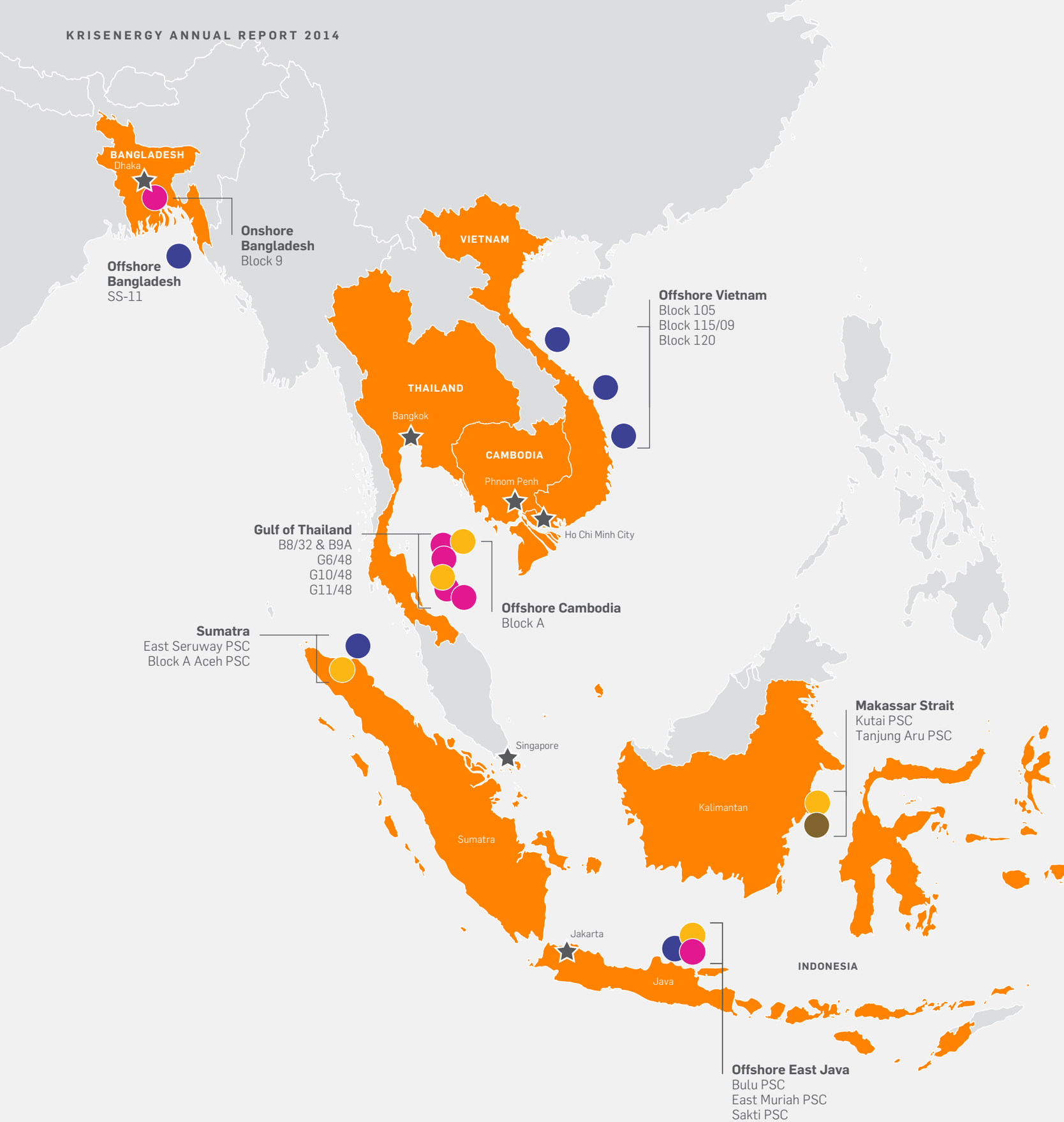
- Keppel Corporation acquired 20% new shares in KrisEnergy for US$115 mm

2013

- Increased size of 2016 Notes to US$120 mm
- Increased RCF to US$42.5 mm
- Initial public offering ("IPO") raised net US$200.5 mm

2014

- Repayment of US$120 mm 2016 Notes
- Secured US$100 mm RCF ("2014 RCF")
- Established S$500 mm Medium Term Note Program ("MTN"). Issued:
  - S$130 mm 3-year bond @ 6.25% (Swap to USD LIBOR+5.29%)
  - S$200 mm 4-year bond @ 5.75% (Swap to USD LIBOR+4.47%)



- Production and near production
- Development pending
- Discovery requiring appraisal
- Exploration
- KrisEnergy regional office

PORTFOLIO ACROSS E&P LIFE CYCLE

Our target area stretches from the Surma Basin in Bangladesh in the west to the Papuan Basin in the east, and from offshore southern China in the north to Indonesia in the south.

OUR OFFICES

We are dedicated to establishing and maintaining an on-the-ground presence in the countries in which we have assets. We currently have offices in Dhaka in Bangladesh, Phnom Penh in Cambodia, Jakarta in Indonesia, in Singapore, Bangkok in Thailand and in Ho Chi Minh City in Vietnam. In addition, we have a full complement of operational staff at the Bangora field location onshore Bangladesh.

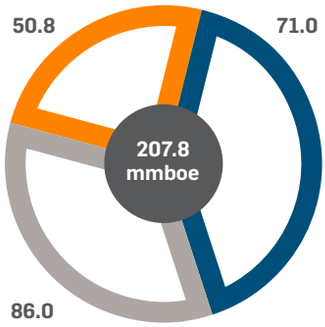
By maintaining local offices in these countries, we are able to respond quickly and efficiently to business opportunities that arise in these areas. Moreover, we largely employ local technical and professional staff, who bring valuable knowledge of the regional geology, business culture and regulatory environment.

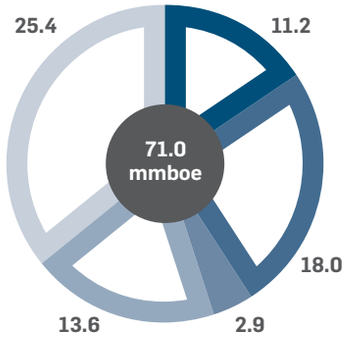


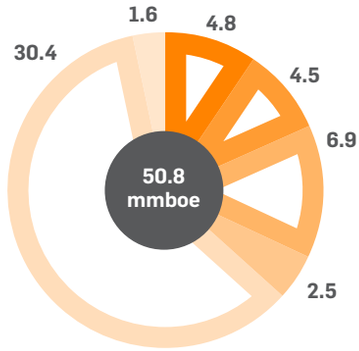


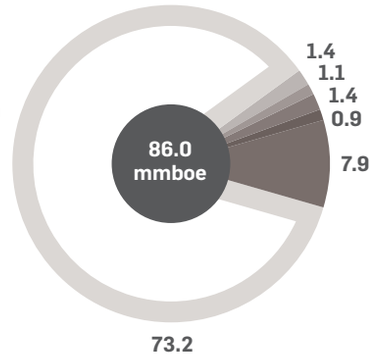
2014 HIGHLIGHTS

All reserves and contingent resources data in the 2014 Annual Report are based on estimates by our third-party independent qualified person, Netherland, Sewell & Associates, Inc. ("NSAI"), as of the date indicated. Numbers may not add due to rounding.









TOTAL 2P RESERVES & 2C RESOURCES[2] (mmboe)

- 2P — reserves
- 2C — development pending
- 2C — development unclarified

PRODUCTION/NEAR PRODUCTION 2P RESERVES (mmboe)

- B8/32 & B9A
- Bangora, Block 9
- Nong Yao, G11/48
- Wassana, G10/48[1]
- Lengo, Bulu PSC

DEVELOPMENT PENDING[3] 2C RESOURCES (mmboe)

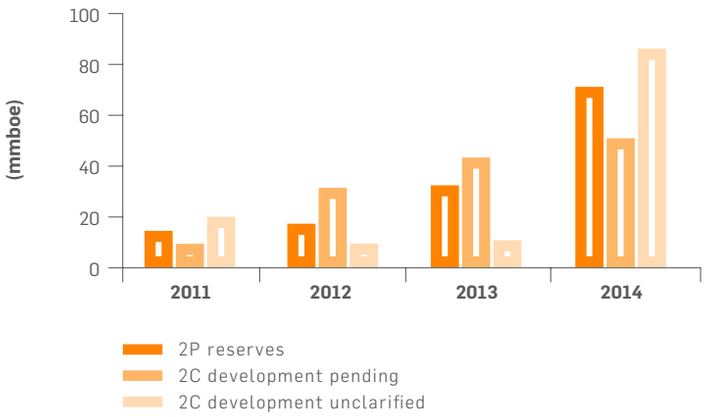
- G10/48[1]
- Cambodia Block A
- Kutai
- G6/48
- Block A Aceh
- East Muriah

DEVELOPMENT UNCLARIFIED[3] 2C RESOURCES (mmboe)

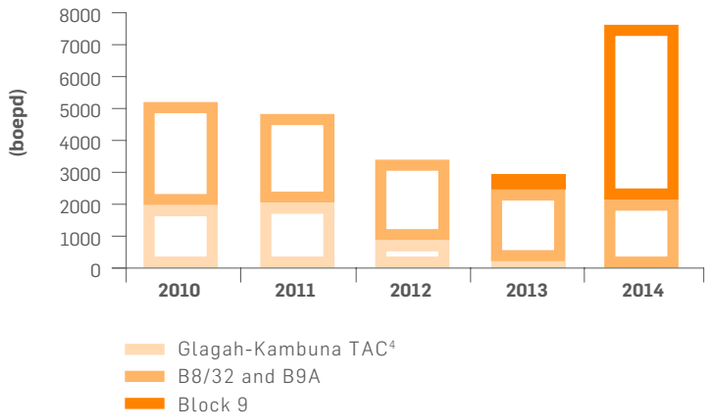
- G10/48[1]
- G11/48
- Cambodia Block A
- Tanjung Aru
- Block A Aceh
- Block 9



2P RESERVES CLIMB 120%



PRODUCTION JUMPS 161% ON BANGORA



- 2P reserves jumped 120% to 71.0 million barrels of oil equivalent ("mmboe") as at 31 December 2014 primarily on conversion of 2C resources for the Wassana oil and Lengo gas developments
- 2C resources increased 154% to 136.8 mmboe as at 31 December 2014 due to the acquisition of Block A Aceh in Indonesia

WASSANA GETS GREEN LIGHT

- KrisEnergy announced final investment decision ("FID") in June 2014 for the development of the Wassana oil field in G10/48 in the Gulf of Thailand. All key components of the development concept have been secured. Wassana is expected to begin production in the second half of 2015

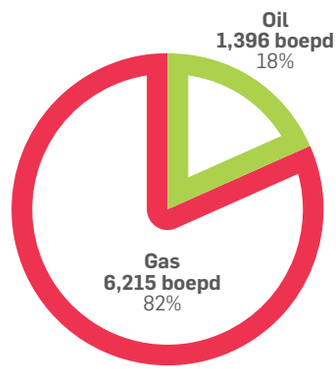
LENGO JUMPS FIRST HURDLE

- Indonesia's regulator sanctioned in late 2014 the plan of development ("POD") for the KrisEnergy-operated Lengo gas field in the Bulu production sharing contract ("PSC"). The field is expected to start supplying gas to the energy hungry East Java market in 2017

EXPANDING FOOTPRINT

- 2014 saw a number of corporate acquisitions and direct government awards as KrisEnergy continued to grow its portfolio of operated and non-operated assets:
  - In M&A activity, the company extended its working interest and took over operatorship of G10/48 and Cambodia Block A, both in the Gulf of Thailand. It also acquired a non-operated working interest in Block A Aceh, where three gas fields are approved for development
  - Organic growth came from the award of operatorship for the Sakti PSC offshore East Java and Block 115/09 offshore north-central Vietnam. We also gained a non-operated working interest in the SS-11 shallow water exploration block in the Bay of Bengal, offshore Bangladesh

- Average working interest production in 2014 increased 161% versus 2013 to 7,612 barrels of oil equivalent per day ("boepd") as a result of a full year's contribution of the Bangora gas field, onshore Bangladesh



NOTE: Numbers may not add due to rounding

DEBT MANAGEMENT

- Redeemed US$120 million 10.5% senior secured guaranteed bonds in January 2014
- Secured US$100 million RCF with facility to increase up to US$140 million with the addition of 2P reserves
- Established in May 2014 a S$500 million multi-currency MTN Program. A successful S$130 million issuance in June 2014 was followed by a second oversubscribed issue for S$200 million in August 2014 and more than halved the company's effective cost of borrowing

[1] On 5 February 2015, we completed the sale of 14.67% shareholding interest in KrisEnergy Management Ltd to Palang Sophon. KrisEnergy Management Ltd holds 100% of KrisEnergy G10 (Thailand) Ltd, which holds 75% working interest in G10/48. Our wholly owned entity, KrisEnergy (Gulf of Thailand) Ltd, holds the remaining 25% working interest in, and operatorship of G10/48

[2] 2P reserves refers to proved plus probable reserves and 2C resources refers to best estimate contingent resources in accordance with the definitions and guidelines in the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers

[3] Development pending refers to a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. Development unclarified refers to a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay

[4] The Kambuna gas field in the Glagah-Kambuna Technical Assistance Contract ("TAC") ceased production in July 2013

OUR CHAIRMAN



WILL HONEYBOURNE
Non-executive Chairman

Dear Shareholders,

The KrisEnergy team took another significant step in 2014 toward the goal of building a sustainable and diversified Asian oil and gas company, with progress in four key areas standing out as particularly noteworthy.

First was the expansion of KrisEnergy's portfolio. The company entered into four new contract areas and, importantly, increased its interest in two key licences while taking over operatorship. This latter point means that, notwithstanding external factors, KrisEnergy has control over the budget and timing of two major oil developments — Wassana and Apsara. The portfolio now contains 19 contract areas in five countries with a relatively even distribution between exploration, appraisal, development and production.

The team made solid progress in bringing oil and gas accumulations towards commercial production. With two assets expected to come on stream during 2015 and two more before the end of 2017, we believe that the near-term outlook for improved earnings and cash flow is bright. KrisEnergy also continued to execute on planned exploration activities that are necessary to drive longer-term growth.

KEY METRICS

Portfolio growth together with advances in development projects resulted in significant increases in fundamental metrics for an upstream oil and gas company: production and reserves and resources. KrisEnergy's average net production in 2014 climbed 161% to over 7,600 boepd, while working interest 2P reserves and 2C resources expanded to almost 208 mmboe.

Another major accomplishment for the group in 2014 was the two successful offerings under the multi-currency MTN Program that strengthened the company's balance sheet and more than halved the cost of debt. Although borrowing has increased from these issuances, the company's gearing remains at a comfortable level below 40%.

In our view, these achievements leave KrisEnergy well placed to weather the storm in global oil markets that began in the second half of 2014, and to potentially take advantage of opportunities that may arise at favourable valuations. The price of benchmark Brent oil fell from US$112 per barrel in June to US$57 at year end, with volatility continuing into the first quarter of 2015. Understandably, investor sentiment towards the upstream oil and gas sector has weakened significantly as a result.

However, it is important to point out that diversification of KrisEnergy's portfolio across different fiscal regimes and hydrocarbon types provides a level of resilience. Gas sales under long-term contracts offer a buffer against less stable oil prices. The company also has the flexibility to allow the deferral of capital expenditure for exploration at a time when the core focus of activity is in the development phase to bring projects into production and increase cash flow.

SAFETY FIRST & FOREMOST

A well-run company is a safely run company, therefore it is pleasing to note that there were no interruptions related to health and safety incidents during KrisEnergy's 1,772,882 man-hours of activities at operated assets in 2014.

We welcomed Alan Nisbet and Keith Pringle to our Board in May, bringing the number of non-executive independent directors to six. Alan has a strong executive track record in accounting, audit, corporate governance, risk management and IT security. Keith is an oil-industry veteran with substantial international operating experience and technical expertise.

Our Board provides great depth and balance in skills, experience and knowledge of the company, the industry and the region, and we are committed to KrisEnergy's long-term success and to ensuring that its governance is fully aligned with the core principles of respect, integrity and transparency.

On behalf of the Board of Directors, I thank you for your support.

Sincerely,



WILL HONEYBOURNE
Non-executive Chairman

28 February 2015

OUR CHIEF EXECUTIVE OFFICER





KEITH CAMERON

Chief Executive Officer

KrisEnergy made good progress towards strategic and operational goals in 2014. Our oil and gas production more than doubled as did our year-end 2P reserves. We made solid advances in several development projects and we strengthened our capital structure and reduced our effective cost of borrowing by more than half. These are all key performance indicators for a high-growth exploration and production ("E&P") operator. However, our successes were somewhat overshadowed by the precipitous drop in world benchmark oil prices in the second half of the year, which impacted revenues and resulted in a revaluation of E&P equities globally.

Although not immune to turbulence in the commodity markets, our strategy of portfolio diversification across a range of fiscal regimes and a combination of oil and gas assets provides a level of cushioning against price volatility. Pipeline gas in Asia is generally sold under long-term contracts, the prices for which are either fixed or reviewed in reference to the relevant benchmark every six to 12 months. In 2014, 82% of our production was gas and 18% oil and liquids, while our 2P reserves at the end of the year comprised 68% gas and 32% oil and liquids. Although the production profile will change as various new developments are brought on stream, we believe our diversified portfolio is well positioned to benefit from relative stability in gas pricing as well as any upside potential from a recovery in oil prices.





STRENGTHENED BALANCE SHEET FOR INVESTMENT

Our decision to restructure and extend our borrowings with bond issuances in June and August 2014 has proved particularly advantageous with appetite for high-yield E&P corporate debt having since fallen away due to oil price movements. From a 10.5% coupon at the beginning of 2014, our effective cost of debt is now approximately 5% and our gearing, or total debt-to-debt and equity, is 38.1%, which is at the mid-point of our target range of 30-50%. Although this restructuring resulted in non-recurring expenses of US$20.4 million for 2014, we have more than doubled borrowings to US$263 million from US$120 million at the start of 2014 and we will benefit from our effective lower interest rates going forward.

The strengthening of our balance sheet and positive net cash flow from operations allowed us to continue to invest in our existing portfolio and maintain growth. We signed three corporate transactions in 2014, acquired production equipment and met our exploration and development capital expenditure requirements. The transfer of operatorship to KrisEnergy for G10/48 and Cambodia Block A, both in the Gulf of Thailand, were transformational steps in taking these two flagship development projects forward.

DEVELOPMENTS LIFT 2P RESERVES

Pre-planning and preparation enabled us to quickly secure all major components for the G10/48 Wassana development in order to declare FID in June 2014, just five weeks after completing the acquisition of a 75% working interest and taking over operatorship of the block. Much of the work for the refurbishment of a mobile offshore production unit ("MOPU") and a floating storage and offloading ("FSO") vessel is complete and we are on target for first oil in the second half of 2015. This progress allowed us to recognise the conversion of 13.6 million barrels of oil ("mmbo") of 2C resources to 2P reserves at the end of the year.

Similarly, since we became the operator of Cambodia Block A in October 2014, our negotiations with the Cambodian authorities over the Apsara oil development project have made advances across all technical and fiscal areas. In parallel, we are laying the groundwork to be able to accelerate development activities once the paperwork is in place. The Apsara development is a tremendous opportunity with potential to be a major producing asset in Asia once the first platform is installed and reservoir performance is confirmed.

Our year-end 2P reserves received a further boost of 25.4 mmboe from the KrisEnergy-operated Lengo gas accumulation in the Bulu PSC in Indonesia. The approval of the Lengo POD was granted by the Indonesian authorities in late 2014 and our project team in Jakarta is now working on front-end engineering studies and is in discussions to finalise long-term gas offtake agreements.

Overall our total working interest 2P reserves grew 120% to 71.0 mmboe as at 31 December 2014, while 2C resources more than doubled to almost 137 mmboe as a result of our acquisition of a non-operated working interest in Block A Aceh, onshore Sumatra in Indonesia. This asset contains three gas fields with an approved POD as well as an exciting discovery that requires appraisal. Our transaction was completed in January 2015 and we were delighted when the operator announced shortly after that it had signed an initial gas sales agreement paving the way for development activities to commence.

PRODUCTION, REVENUE AND EBITDAX[1] RISE

Average 2014 working interest production increased 161% to 7,612 boepd as a result of the 2013 acquisition of the Bangora gas field onshore Bangladesh.

Higher production lifted 2014 revenues by 8.5% to US$74.9 million in spite of a 7.7% decline in the average realised oil price to US$100.93 per barrel ("bbl"). Our EBITDAX, which is a global measure of core profitability within the E&P sector, rose 8.4% to US$30.5 million, just within our target range. However, for the full year we posted a loss after tax of US$50.3 million primarily due to non-recurring charges and one-off non-cash adjustments related to our debt restructuring and other finance costs, along with higher operating costs associated with depreciation, depletion and amortisation charges for our producing properties.

STRONG FUNDAMENTALS

KrisEnergy remains on track to execute on a handful of near-term development projects starting with first production in 2015 at the Nong Yao and Wassana oil fields in the Gulf of Thailand, followed by two gas fields in Indonesia in 2017.

We have maintained a steady level of ground-floor exploration activity with the acquisition of a number of 2D and 3D seismic programs in 2014, which will provide prospects and leads for future exploration drilling. Our capital expenditure budgets out to 2018 will heavily focus on development activities as we bring new production on stream. However, exploration is an important thread of our overall business strategy in building a sustainable E&P company and we will constantly review the rig markets and oil services costs for opportunities to drill exploratory wells on a cost-effective basis.

We have little by way of immediate exploration obligations under our concessions and therefore we have discretion and flexibility over our work programs to maximise efficiencies and control expenditure. In adjustment to the anticipated lower oil price environment in 2015, we will continuously review opportunities to cut general and administrative costs without compromising operations and health and safety.

The long-term outlook for the oil and gas industry remains positive despite concerns over short-term global uncertainties and the depressed oil price environment. Uncertainty provides opportunity and a potential springboard for new ventures and portfolio growth. We will continue to be disciplined in our technical review and strategic alignment when assessing such opportunities. Not least, strong economic fundamentals in Asia, together with the region's rapid population growth, rising middle class and economic development, will continue to drive energy demand in our geographical area of focus.

I would like to thank the Board of Directors for their guidance, our shareholders for their continued support and the KrisEnergy teams in all the countries in which we operate for their hard work in 2014. Activity has ramped up as we strive to execute our projects on time and to budget while maintaining our environment, health, safety and security ("EHSS") standards that comply with or exceed best industry practices.



KEITH CAMERON
Executive Director, Chief Executive Officer

28 February 2015

[1] Earnings before interest, taxation, depreciation, amortisation, geological and geophysical expenses and exploration expenses ("EBITDAX"). EBITDAX is a non-IFRS measure



SPOTLIGHT ON THAILAND

WASSANA OILS GROWTH ENGINE

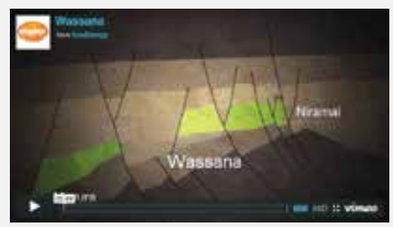
Many at KrisEnergy have had a long and productive relationship with the Gulf of Thailand, so it is fitting that the first oil from a field under our operatorship is scheduled to start flowing in the second half of 2015 from the Wassana discovery in the Pattani Basin.

Ian Anderson, VP Exploration Thailand, describes KrisEnergy's debut development.

VIDEO

WASSANA

http://krisenergy.com/videos/wassana/



Scan the QR code to watch the video

The Pattani Basin spans a 500 km swath of the Gulf of Thailand that is the richest source of hydrocarbons in the Southeast Asian nation. There have been numerous gas discoveries in the central part of the basin, most of which were made in the 1980s and 1990s. Then in 2009, oil was discovered on the shallower margins to the south within the 4,700 sq. km G10/48 contract area.

Just two months after KrisEnergy was established in 2009, we acquired a 25% stake in each of G10/48 and the neighbouring G11/48 licence. The same year, we participated in our first drilling program. Three oil discoveries were made in G10/48 and one of these – Wassana — found a medium-gravity crude oil that flowed easily to surface. Three subsequent appraisal wells confirmed accumulations of oil-bearing sands. Of the three discoveries in G10/48 – Niramai, Wassana and Mayura – Wassana is the largest, with 13.6 million barrels of recoverable oil. A commercial oil discovery — Nong Yao — was also made in G11/48 in 2009 which, like Wassana, is being developed and is due to begin production in 2015.

The Wassana, Niramai and Nong Yao fields were all discovered on the basis of 2D seismic data, but in 2010 a high quality 554 sq. km 3D seismic survey was acquired over Wassana and processed in order to determine the location of three successful appraisal wells later that same year.

FRAGMENTED ACCUMULATIONS

The Pattani Basin's plentiful reserves, shallow seas and relatively benign conditions — barring the occasional typhoon — flatter to deceive: the oil is trapped in multiple locations within thin, stacked layers of fluvial sandstone that were deposited about 20 million years ago. The geological formations meant that while the basin may be prolific, the small pockets of accumulations tend to be quickly depleted. The ability to execute efficiently and continuously along the entire hydrocarbon life cycle, from exploration to development to production, is therefore crucial to commercial success in the Gulf of Thailand.

In May 2014, KrisEnergy took over as the operator of G10/48 and quickly assembled a project team to secure the key components for development of Wassana. Here, their previous experience with greenfield Gulf of Thailand developments proved invaluable. Water depth of about 50 metres and a relatively flat seabed meant that the ideal development solution was a MOPU.

The *MOPU Ingenium* is a converted jack-up rig in which the drilling equipment has been replaced with an oil and gas processing system. Once it has been towed to location, its legs will be lowered to the sea floor and the rig jacked clear of the water, sufficiently high enough to avoid waves generated by the worst typhoons that can be expected to hit the region. The *MOPU Ingenium* accommodates 39 crew on rotation, who fly to and from the rig from the Thai town of Songkhla 140 km away. The jack-up rig *Key Gibraltar* will then be brought into place next to the MOPU to undertake a four-month development drilling campaign.

Drilling through the 1,500 metres of rock to the oil is not technically difficult, but the fragmented nature of the accumulations presents its own challenges. About half the wells at Wassana will be drilled horizontally, twisting and turning to find the elusive pockets of oil. To maximise recovery, other wells will pass through several "sweet spots", like threading pearls onto a necklace.

The mixture of oil, water and gas from the wells will be separated on the MOPU. The gas provides fuel for on-board generators, while the water is pumped back into the reservoir to avoid discharge into the sea. A 2 km pipeline installed on the sea floor

The *MOPU Ingenium* on tow in November 2014 to Batam, Indonesia



Work commences to refurbish the *MOPU Ingenium* in dry dock in Batam, Indonesia



will carry the oil to a catenary anchor leg mooring ("CALM") buoy, where it will be transferred to an FSO vessel that is able to store approximately 500,000 barrels of oil. The CALM buoy rotates to compensate for the FSO's motion and allows the tanker to quickly disconnect and move off station if a typhoon is forecast.

As of 28 February 2015, the *MOPU Ingenium* was undergoing refurbishment in Batam, Indonesia, and the *FSO Rubicon Vantage* was in drydock in Thailand for modifications before being towed to the Wassana location. All the key assets and services required for the development have been secured and KrisEnergy's team is preparing for full-scale mobilisation of the production plan.

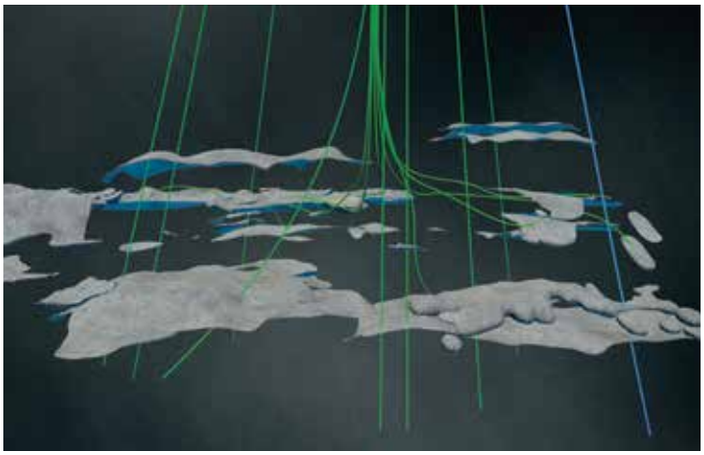
At its peak, up to 15 wells at the Wassana field will produce about 10,000 barrels of oil per day, with an expected life of around seven years. Once depleted, the MOPU and associated facilities can be moved, to other locations where discoveries are ready for development. During Wassana's lifetime, further appraisal and development of the Niramai and Mayura fields together with exploration of numerous prospective areas in G10/48 could mean a long and nomadic career for the *MOPU Ingenium* as it migrates from one discovery to the next.

Photos courtesy of Rathapol Limthongchai and Ryan Tan

Refurbishment of the seawater lift tower used for utilities cooling and fire water / deluge supply on the MOPU



Up to 15 wells in the Wassana development will thread their way through the thin, stacked layers of fluvial sandstones



The CALM buoy (right) rotates to compensate for the FSO's motion. Disconnect is quick if a typhoon is forecast



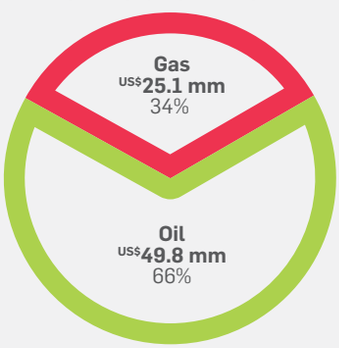
FY2014 FINANCIAL SUMMARY

REVENUE

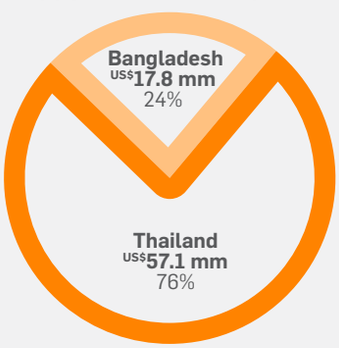
US$ 74.9 mm **+8.5%**

(2013: US$69.1 mm)

OIL TO GAS RATIO



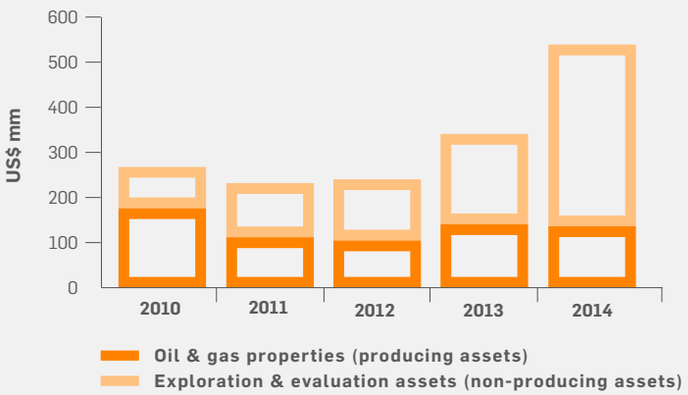
COUNTRY BREAKDOWN



OIL & GAS ASSETS

US$ 539.1 mm **+58.0%**

(2013: US$340.9 mm)



EBITDAX

US$ 30.5 mm **+8.4%**

(2013: US$28.2 mm)

LOANS & BORROWINGS

US$ 257.4 mm

(2013: US$119.1 mm)

LIFTING COST

US$ 6.91 /boe **-54.4%**

(2013: US$15.14/boe)

GEARING AT 31 DECEMBER 2014

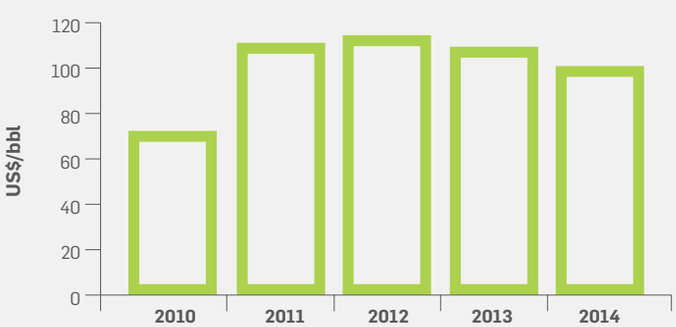
38.1%

(2013: 20.3%)

REALISED OIL SALES PRICE

US$ 100.93 /bbl

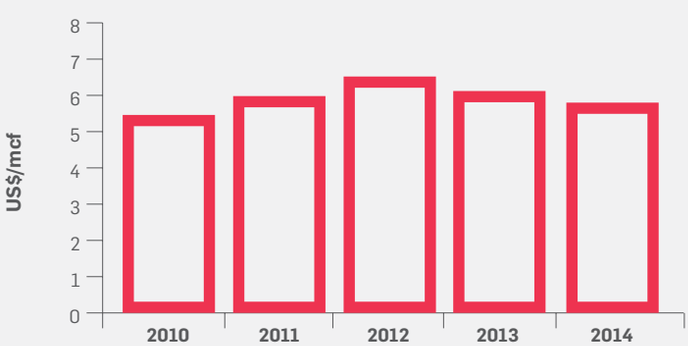
(2013: US$109.40/bbl)



REALISED GAS SALES PRICE (excludes Bangladesh)

US$ 5.80 /mcf

(2013: US$6.06/mcf)





FINANCIAL REVIEW



KIRAN RAJ

Chief Financial Officer, Vice President Finance

Balance-sheet management remained core to our financial strategy in 2014. We executed a series of transations in the debt capital markets and completed three strategic and potentially accretive acquisitions. As we move into 2015, KrisEnergy remains well placed to deliver on its pipeline of development projects with first oil from two fields in the Gulf of Thailand within sight.

We returned US$126.6 million to bondholders with the redemption on 30 January 2014 of 10.5% senior guaranteed secured notes due July 2016 with a face value US$120.0 million. Subsequently, we focused on the debt capital markets to achieve our target gearing.

We established our inaugural US$100.0 million 2014 RCF in March 2014, which allows us to fund our group working capital requirements. We are currently working with our lenders to increase the 2014 RCF to as much as US$140.0 million based on the increase in 2P reserves at the end of 2014.

In May 2014, we established a S$500.0 million multi-currency MTN Program, which was followed by two successful senior fixed-rate note issues: (i) S$130.0 million senior three-year fixed-rate notes due June 2017 (the "2017 Notes"); and (ii) S$200.0 million senior four-year fixed-rate notes due August 2018 (the "2018 Notes"). Following a series of US dollar interest rate swap transactions, we reduced our effective cost of debt from 10.5% at the end of 2013 to approximately 5.0% at the end of 2014.

We will continue to implement prudent capital management strategies in 2015. Our existing production from the Bangora gas field in Block 9 and oil and gas production from the B8/32 and B9A licences in the Gulf of Thailand will underpin our baseline production, revenue, EBITDAX and free cash flow. In addition, we expect to bring on stream incremental production in the second half of 2015 from the Wassana and Nong Yao oil fields, which will enhance production, revenue and EBITDAX.

To further support planned capital expenditure in 2015 and as part of our risk mitigation strategy, we intend to farm out working interests in certain assets within our portfolio and to divest interests in select assets to realise gains on investment. Such corporate actions are not only in line with our strategy but within our ordinary course of business.

As at 31 December 2014, our total gearing was 38.1%, at the mid-point of our target range. Coupled with cash flow from existing operations, cash flow from new production in 2015 and unutilised sources of liquidity from the 2014 RCF, we believe we have followed best practices to reduce our cost of borrowing and ensure our balance sheet is structured to optimise the company's operations.

NEAR-TERM ACCRETIVE ACQUISITIONS

In our relatively short history, we have grown our portfolio organically and delivered accretive acquisitions to shareholders, with 2014 being no exception. In May 2014, we acquired the remaining 75.0% working interest and operatorship of the G10/48 concession, which contains three discoveries. Following the completion of the transaction, we accelerated the development of the Wassana oil field, where we expect to deliver first oil in the second half of 2015. As a result of our development progress, we converted 13.6 mmbo of 2C resources to 2P reserves at the end of 2014.

We acquired an additional 30.0% working interest and took over the operatorship of Cambodia Block A. Since October 2014, we have engaged actively with the highest levels of government to obtain approval for the Apsara development. We expect to declare FID in 2015, targeting first oil within 24 months from that point.

In January 2015, we completed the acquisition of the entire issued and paid-up share capital of Premier Oil Sumatra (North) B.V. (since renamed KrisEnergy (Block A Aceh) B.V.), which holds a 41.6666% working interest in Block A Aceh. We view this acquisition as core to our Indonesian gas portfolio, where realised prices under long-term contract are more stable than spot oil markets. Since completion of our transaction, the operator, PT. Medco E&P Malaka, has signed a gas sales agreement with a price fixed at US$9.45 per million British thermal units ("mmBtu").

We funded the 2014 acquisitions through a combination of proceeds from the 2017 Notes, 2018 Notes and cash on hand, and we remain focused on delivering near- to medium-term cash flow from these developments.

REVENUE

Audited consolidated net revenue increased 8.5% to US$74.9 million (2013: US$69.1 million) for the financial year ended 31 December 2014 as a result of a 161% rise in production for the group, which was driven by a full year's contribution from the Bangora gas field. However, the fall in global oil prices in the second half of 2014 resulted in a 7.7% decline in the average selling price for oil and liquids to US$100.93/bbl. The average gas price achieved from our gas assets in Thailand decreased 4.2% to US$5.80 per thousand cubic feet ("mcf") due to penalties arising from production falling below the daily contracted volume in the third and fourth quarters of 2014. Future gas production in B8/32 and B9A will be boosted by two platforms to be commissioned by mid-2015.

FOR THE YEAR ENDED 31 DECEMBER

Sales of crude oil	49.8	54.7
Sales of gas	25.1	14.4
Revenue (US$ million)	**74.9**	**69.1**
PRODUCTION VOLUMES		
Oil and liquids (bopd)	1,396	1,366
Gas (mmcfd)	37.3	9.3
Total (boepd)	**7,612**	**2,916**
SALES VOLUMES		
Oil and liquids (bopd)	1,395	1,366
Gas (mmcfd)	36.3	8.6
Total (boepd)	**7,448**	**2,801**
AVERAGE SALES PRICE		
Oil and liquids (US$/bbl)	100.93	109.40
Gas[2] (US$/mcf)	5.80	6.06

[1] Includes contribution from Block 9 (December 2013) and the Glagah-Kambuna TAC, which ceased production in July 2013

[2] Average realised gas sales price from B8/32 and B9A in Thailand

COST OF SALES

Cost of sales increased 26.6% to US$55.2 million (2013: US$43.6 million) primarily due to of higher depreciation, depletion and amortisation ("DDA") charges as well as an increase in operating costs.

DDA charges increased to US$28.7 million (2013: US$19.4 million) as a result of the contribution from the Bangora gas field and a non-recurring adjustment associated with decommissioning costs at the Glagah-Kambuna TAC. Operating costs increased to US$19.2 million in 2014 (2013: US$16.1 million) due to the recognition of a full year of production from the Bangora gas field. The increase in cost of sales was partially offset by lower Thai petroleum special remuneratory benefits and royalties paid as a result of a 5.2% year-on-year decrease in production from B8/32 and B9A during 2014.

The production contribution in 2014 from the Bangora field led to a 54.4% decrease in the group-wide average lifting cost to US$6.91 per barrel of oil equivalent ("boe") (2013: US$15.1/boe). The Bangora gas field's low cost of production makes it our highest margin contributor in the group, even with the relatively low realised sales price of US$2.32/mcf.

FOR THE YEAR ENDED 31 DECEMBER

Cost of sales (US$ million)	55.2	43.6
AVERAGE LIFTING COST		
Oil, liquids and gas (US$/boe)	6.91	15.14
Operating costs (US$ million)	19.2	16.1
Total production (mmboe)	2.8	1.1

EBITDAX

EBITDAX increased 8.4% to US$30.5 million (2013: US$28.2 million) and was in line with our expectations.

FOR THE YEAR ENDED 31 DECEMBER

EBITDAX (US$ MILLION)	**30.5**	**28.2**
(Loss)/Profit before tax (US$ million)	(39.3)	0.1
Tax expense (US$ million)	(11.1)	(12.8)
Loss after tax (US$ million)	**(50.4)**	**(12.6)**

FINANCE COSTS

2014 was a transformational year as we implemented and executed a defined debt capital markets strategy to take advantage of the lower interest rate environment and the significant appetite for oil and gas debt securities. Although finance costs increased to US$23.2 million in 2014 (2013: US$13.3 million), we significantly reduced our cost of borrowing from 10.5% to approximately 5.0% whilst increasing total borrowings to support potentially accretive acquisitions as well as progress the development of our projects. Higher finance costs were attributable to one-time expenses of US$8.2 million relating to the redemption of the 2016 Notes and fees of US$4.7 million associated with the establishment of the 2014 RCF, the MTN Program and the ensuing two bond issuances. Interest expense was US$7.4 million as a result of borrowings amounting to US$273.9 million in 2014.

LOSS/PROFIT BEFORE TAX

We recorded a loss before tax of US$39.3 million in 2014 (2013 profit before tax: US$0.1 million) as a result of a decrease of US$13.2 million in gross profit contribution from the Glagah-Kambuna TAC, which ceased production in 2013, and a reduction in production and associated realised gas prices from B8/32 and B9A. In addition, we incurred non-recurring expenses associated with debt restructuring.

CAPITAL EXPENDITURE & CAPITAL INVESTMENT

In accordance with International Financial Reporting Standards, we reclassified in 2014 our capital expenditure for exploration, appraisal and development. Exploration and appraisal expenditure includes, among others: spending on exploration and appraisal wells; geological and geophysical activities; general and administrative costs; field development costs; platform and facility costs; and pipeline and equipment costs as they relate to non-producing assets. This includes development activities in relation to Nong Yao and Wassana. Expenditures in the development classification relate to cost incurred in producing assets, namely B8/32, B9A and Block 9.

Exploration and appraisal expenditure increased 27.8% to US$82.6 million (2013: US$64.6 million), which was primarily attributed to seismic acquisition amounting to US$24.6 million in the Udan Emas PSC, Sakti PSC and Tanjung Aru PSC in Indonesia; exploration wells drilled and capitalised in the G10/48 and G11/48 concessions; and ongoing development activities for the Wassana and Nong Yao oil fields. In addition, we spent US$66.2 million in 2014 to secure and commence refurbishment of the MOPU for the Wassana development.

Development expenditure increased 77.3% to US$24.5 million (2013: US$13.8 million). During 2014, our working interest share of development expenditure in B8/32 and B9A amounted to US$22.8 million, representing our participation in the drilling of 55 development wells and the installation of two new platforms that were brought on stream during the year.

The acquisition of additional working interests and operatorships in G10/48 and Cambodia Block A amounted to US$167.2 million.

FOR THE YEAR ENDED 31 DECEMBER

(US$ million)		
Exploration and appraisal	82.6	64.6
Development	24.5	13.8
Acquisitions	167.2	41.4
Others	70.3	2.3
Total	**344.6**	**122.1**

LOANS & BORROWINGS

Following redemption of the 2016 Notes in January 2014, our loans and borrowings at 31 December 2014 amounted to US$311.1 million (2013: US$127.3 million) comprising the drawn amount of the 2014 RCF and the 2017 Notes and 2018 Notes.

FOR THE YEAR ENDED 31 DECEMBER

(US$ million)		
Amount repayable in one year or less	25.1	127.3
Amount repayable after one year	286.0	–

CASH

As a result of increased development activities, net cash flow from operations declined 61.1% to US$6.3 million (2013: US$16.2 million). This was primarily driven by non-recurring expenses in relationto debt restructuring, increase in inventories, trade and other receivables as well as the decrease in trade and other payables.

Construction of the Nong Yao facilities *(Photos courtesy of Mubadala Petroleum)*



Net cash flow used in investing activities increased 182.3% to US$344.6 million (2013: US$122.1 million) following the acquisition of the additional working interests in G10/48 and Cambodia Block A and continued investment in portfolio growth through exploration, appraisal and development activities.

Net cash flow from financing activities decreased 40.5% to US$138.0 million (2013: US$231.8 million). We redeemed the 2016 Notes and returned US$126.6 million to bondholders, which comprised principal repayment, a redemption premium and accrued interest. We issued the 2017 Notes and 2018 Notes and following a series of US dollar swap transactions, realised gross proceeds of US$263.9 million.

FOR THE YEAR ENDED 31 DECEMBER

(US$ million)		
Net cash flow from operating activities	6.3	16.2
Net cash flow used in investing activities	(344.6)	(122.1)
Net cash flow from financing activities	138.0	231.8
Cash at banks and on hand	47.3	247.8
Short-term structured deposits	4.0	4.0
Cash and bank balances	51.3	251.8

IPO PROCEEDS

After deducting expenses associated with the 2013 IPO, we received net proceeds of US$200.5 million. During 2014, the IPO proceeds were fully utilised.

(US$ million)		
Net IPO Proceeds	200.5	200.5
Utilisation		
Tranche 1: For acquisitions (including farm-ins)	59.9	59.9
Tranche 2: For our planned capital expenditures, including the exploration, appraisal and development of our existing assets	111.1	111.1
Tranche 3: For general working capital	29.5	29.5
Total utilisation of net IPO proceeds	**200.5**	**200.5**

2015 OUTLOOK

As we enter 2015, significant uncertainty remains over the timing and price levels at which the global oil markets will stabilise. With this in mind, we have made deliberate efforts to ensure our work programs and capital budgets are focused on delivering near-term growth to shareholders. Our 2015 planned capital expenditure amounts to US$269.4 million, however our budget does not take into account any benefits we may derive from cost savings under current market conditions. Further, our planned capital expenditure is largely discretionary and therefore we have the flexibility to reallocate and/or defer certain spending.

Our debt capital markets transactions in 2014 laid the platform for our development activities in the Gulf of Thailand where approximately US$128 million of our capital expenditure is to be focused in 2015 with the objective to bring first oil from the Nong Yao and Wassana fields in the second half of the year. Across the portfolio, drilling activity in 2015 will include up to 96 development wells and four exploration and appraisal wells.



Although we endeavour to seek cost efficiencies in all activities, our primary financial strategy is to ensure that our sources and uses of funds are optimally derived and prudently incurred. As such, we will fund 2015 planned capital expenditure from existing cash, cash flow from current production, cash flow from future production in G10/48 and G11/48, the 2014 RCF, proceeds from farm-out transactions and selective strategic asset divestments.

2015 is expected to provide yet another year of growth for KrisEnergy as we increase reserves and resources, production, revenues, EBITDAX and cash flow, while maintaining a vigorous approach to balance sheet management.



KIRAN RAJ
Chief Financial Officer, Vice President Finance

28 February 2015

SPOTLIGHT ON INDONESIA

RUMBLE IN THE JUNGLE

A six-hour flight east of KrisEnergy's Jakarta office brings you to West Papua, a densely forested and mountainous Indonesian province and the site of one of our most challenging and potentially rewarding operations: the Udan Emas seismic acquisition. Geoff Bennett, Chief Geophysicist for the KrisEnergy group, has been supervising the project since 2013.

Our involvement began several years ago, after KrisEnergy's veteran Chief Geophysicist for Indonesia, Rachmat Mudjiono, dug out some old seismic sections and gravity maps of a remote and thinly explored area in West Papua. Those earlier studies from the 1970s hadn't sparked any interest at the time. But Rachmat, drawing on decades of exploration experience and several hydrocarbon discoveries, realised that previous geological studies had only targeted shallow rock formations and that huge gas reserves may be trapped in deeply buried Jurassic sandstones.

Not far to the north lie the massive and prolific Vorwata and Wiriagar fields. There was a good chance that the geological formations in those areas also extended into the Udan Emas PSC, an onshore block covering more than 5,000 sq. km of mountains, jungles and remote villages. Rachmat and Gadjah Eko Pireno, VP Exploration Indonesia, successfully put together a Joint Study Agreement ("JSA") and KrisEnergy was awarded 100% working interest in the Udan Emas PSC in May 2012.

During the first year, Basuki Kusmutarto, General Manager for KrisEnergy Indonesia, and his team met the Bupati and staff of the Kaimana Regency, toured the town of Kaimana and visited several nearby villages, building up the trust needed to gain the cooperation of the local communities.

By June 2013, it was time to begin detailed planning for the seismic program, determining the technical parameters and estimating the costs. This was no easy matter. Rachmat had identified two interesting leads in the eastern part of the block, adjacent to the foothills of the New Guinea mountains. While an earlier 1974 study had acquired data in the easier terrain to the west, no one had shot seismic in our target area. Recognising the magnitude of the challenges, KrisEnergy hired Alan Fenwick, a consultant with a long and successful track record of seismic acquisition in Indonesia.

CROCODILE INFESTED

After much discussion, the geophysical team agreed on a 2D program of 11 lines totalling 300 km. Unlike offshore seismic programs, which rarely encounter obstacles, these lines would have to cross the large but shallow marine bay of Teluk Arguni, surrounded by rugged, jungle-clad hills on the west, soaring limestone peaks to the east, and fringed by crocodile-infested swamps and at least 32 fishing villages. The area is remote, difficult to access and inherently expensive. The challenge is to record good seismic data at a reasonable cost – and to do it safely, with minimal disruption to the environment and the livelihoods of locals.

Operations along a seismic line and socialisation activities in West Papua












Catamaran drilling shot holes offshore *(Photos courtesy of Geoff Bennett, James Carlile, Florencia Ciska and Alan Fenwick)*

VIDEO

UDAN EMAS

http://krisenergy.com/videos/udan-emas/



Scan the QR code to watch the video

"Time spent in reconnaissance is seldom wasted," as the old military adage puts it. We rented a house in Kaimana and then a second one in the village of Bofuwer, closer to the field. Radio and satellite communications were installed, local staff hired and a bank account opened. Scouting missions assessed hazards, security, medical facilities, tides, currents, water depth, mangroves, surface geology, shot-hole drilling conditions, locations for base camp and the explosives magazine, sites for helicopter-landing pads, roads, trails, boats, villages and the local economy.

Basuki visited the area every month with his team, earning respect by being the first General Manager of an oil company to talk to the local people. Florencia Ciska, VP Administration, instituted a program at local elementary schools that touched the lives of almost 1,000 youngsters, teachers and parents. They organised two "sinaras", traditional ceremonies in which the villagers learned about and granted approval for the seismic operation. Team members spent months assessing local fish, crop and timber resources in order to address any problems raised by the seismic study. KrisEnergy's EHSS department, working with Alan, designed and implemented a comprehensive set of procedures for managing hazards and emergencies.

In the meantime, the paperwork slowly ground its way through the bureaucracy: authority for expenditures ("AFEs"); environmental and forestry permits; and contracts for explosives, helicopters, a quality-control team, seismic acquisition and processing. An explosives bunker was constructed near to Wanggita Lama and a seismic base camp was built at Warwasi. Geological teams collected rocks, measured outcrops and sampled a natural gas seep.

On 10 September 2014, the seismic crew officially began to mobilise. Field camps were built to accommodate the growing number of workers. As base camp neared completion, survey teams from contractor PT. Quest Geophysical Asia headed into the jungle. Crews cleared vegetation along the lines and built walkways. Others began the drilling of 6,000 shot holes to depths of 27 metres every 50 metres along the lines and loaded each hole with 3 kg of dynamite. Catamaran-mounted rigs drilled holes in the shallow bay. At a depth equivalent to a seven-storey building, the offshore explosions pose no threat to the fisheries. More than 1,300 people from across Indonesia have been working on the project.

Indonesia's vast archipelago of more than 17,000 islands is spread along the geological fault line known as the Ring of Fire, a region of intense tectonic activity that is prone to earthquakes and volcanic eruptions. The country is divided into 34 provinces, each of which has an elected legislature and Governor. Provinces are further divided into city administrations run by a Walikota and regencies, which are predominantly rural areas governed by a Bupati

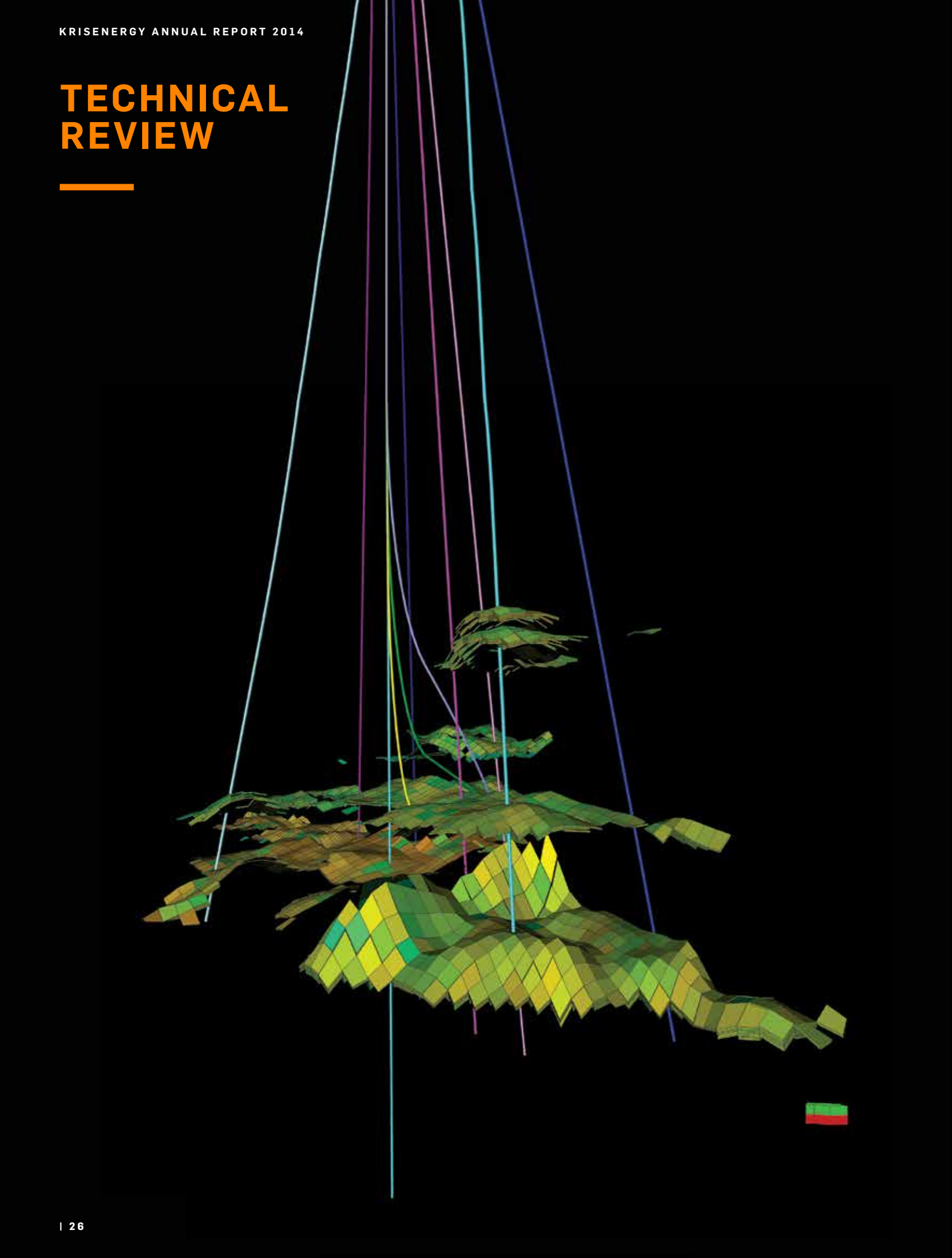
On 26 January 2015, the first shot was fired into a spread of 8,640 geophones across a distance of 12 km. Seismic acquisition should finish in June, after which trees will be replanted and the jungle will reclaim the lines. In parallel, a separate airborne gravity and magnetic survey is being recorded over the entire block.

By the end of 2015, KrisEnergy will have new seismic, gravity, magnetic and geological data with which to evaluate the hydrocarbon potential of Udan Emas.

Rachmat Mudjiono | Gadjah Eko Pireno | Basuki Kusmutarto | Florencia Ciska | Alan Fenwick | Geoff Bennett



TECHNICAL REVIEW





CHRIS GIBSON-ROBINSON

Director Exploration & Production

Activity across our portfolio ramped up in 2014 as we prepared for development projects, acquired or were awarded additional assets and continued our exploration programs. Execution of development projects was predominant after KrisEnergy took over operatorship for G10/48 (Wassana) in Thailand and Cambodia Block A (Apsara), and subsequently in Indonesia with approval of the development plan for the Lengo gas field in the Bulu PSC in the latter stages of the year.

This higher level of KrisEnergy-operated activity has required us to engage additional manpower and cast a spotlight on our health and safety monitoring systems and performance. Our office in Jakarta was awarded OHSAS 18001 certification in December 2014, and the teams in Dhaka and at the Bangora field location received ISO 14001 accreditation in the same month. We are preparing our offices in Bangkok, Phnom Penh and Ho Chi Minh City for audit to achieve these international standards. Our Singapore office is both OHSAS 18001 and ISO 14001 certified.

In 2014, there were 1,772,882 man-hours spent on KrisEnergy-operated assets without a lost time injury.

RESERVES & RESOURCES

Progress in the Wassana and Lengo developments enabled us to convert almost 39.0 mmboe of working interest 2C resources to 2P reserves as estimated by NSAI at 31 December 2014. Our total working interest 2P reserves grew to 71.0 mmboe compared with 32.3 mmboe as at 31 December 2013. This is the fourth consecutive year that we have reported 2P reserves growth.

NSAI reclassified 0.5 mmboe attributed to the Nong Yao development in G11/48 as 2C resources, bringing working interest 2P reserves to 2.9 mmboe. This was related to barrels associated with the Nong Yao-3 exploration well, a location where we currently have no plans to deploy development wells.

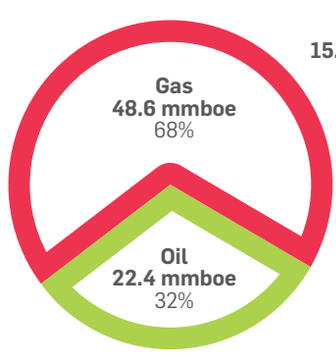
For producing assets, good reservoir performance at the Bangora gas field in Block 9, Bangladesh, led to an upgrade in 2P reserves to almost 18.0 mmboe on a working interest basis and after adjustment for production of 2.0 mmboe. Block 9 was estimated to contain 16.2 mmboe of working interest 2P reserves at the end of 2013. NSAI's estimates for the B8/32 and B9A oil and gas fields in the Gulf of Thailand decreased to 11.2 mmboe as at 31 December 2014 from 12.7 mmboe a year earlier, after adjustment for working interest production of 0.8 mmboe.

Our acquisition in June 2014 of a 41.6666% non-operated working interest in Block A Aceh, onshore Sumatra, resulted in an uplift to our total working interest 2C resources to 136.8 mmboe at the end of the year, of which 30.4 mmboe are in the development pending category and are associated with three gas fields in Block A Aceh with an approved POD. An additional 73.2 mmboe of working interest 2C resources in the development unclarified class include the Matang gas discovery, which requires appraisal, and the high carbon dioxide Kuala Langsa gas accumulation, both of which are in Block A Aceh.

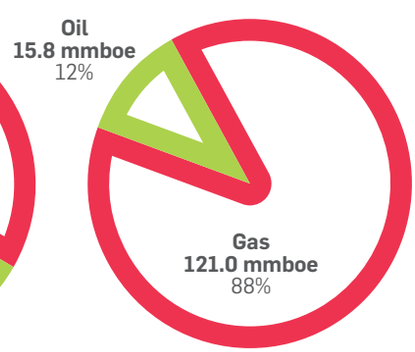
RESERVES REPLACEMENT

	2011	2012	2013	2014
2P reserves at 31 December (mmboe)	14.38	17.16	32.30	71.00
Average production (boepd)	4,817	3,384	2,916	7,612
Total production (mmboe)	1,759	1,235	1,064	2,778
Reserves replacement ratio (%)		325	1,523	1,492

2P RESERVES OIL VS GAS



2C RESOURCES OIL VS GAS



PRODUCTION

Average working interest production in 2014 was 7,612 boepd, a rise of 161% from 2,916 boepd in 2013, with gas accounting for 82% of the production mix. The incremental production streams from the Nong Yao and Wassana oil fields in the second half of 2015 will provide additional growth, rebalancing our production profile to an approximate 40:60 split between gas and oil. This will likely remain the proportions until the Lengo and Block A Aceh fields commence operations in 2017 and provide a firm base of gas production in Indonesia.

Monthly average production at the Bangora field was consistently above 107 mmcfd in 2014, only declining below 100 mmcfd in October as a result of planned maintenance and brief stoppages to commission three newly installed compressors.

Development work met expectations in the B8/32 and B9A fields with 55 wells drilled and two new platforms brought on stream. In addition, in-fill drilling resulted in the resumption of production at three platforms. Having started 2014 with the strongest output rates since 2011, reaching in excess of 55,000 boepd in some months on a gross basis, production at B8/32 and B9A declined significantly in the second half of the year, partly as a result of poor weather hampering maintenance operations at some of the platforms. Gas flow rates were further constrained in the fourth quarter while a processing unit was modified. Our average working interest production from Thailand for the year was 2,134 boepd.

DEVELOPMENT

Construction of the Nong Yao production and processing facilities was completed in February 2015 and work will begin shortly to install the pipelines, wellhead platform and the processing platform. The FSO vessel is being refurbished in China. Development drilling in G11/48 is scheduled to commence in the second quarter of 2015.

Similarly, refurbishment of the MOPU and FSO vessel for our flagship Wassana oil development in G10/48 is nearly complete. Pre-planning during negotiations to take over the G10/48 operatorship meant that we were able to quickly assemble a project management team and secure the key components for the development as well as arrange yard facilities for the necessary refurbishment and construction work. Wassana is expected to produce first oil in the second half of 2015, which will be less than 18 months after KrisEnergy became the operator of the block. For details on the Wassana development see *Spotlight on Thailand: Wassana Oils Growth Engine* on pages 16–17.

We have focused on the development concept and cost efficiencies since taking over operatorship of Cambodia Block A on 1 October 2014. The joint-venture partners have submitted to the government authorities a plan for a staged development of the Apsara area starting with a single wellhead platform connected to a production barge with oil stored on an FSO. This will be the first hydrocarbon production from the Khmer Basin and therefore, once the development plan is approved and the facilities are installed and on stream, we envisage a period of monitoring reservoir performance before commencing work on a second phase of three additional platforms.

For the Lengo gas development, our first operated gas project in Indonesia, we have completed initial front-end engineering design and are preparing to tender for the engineering procurement construction and installation contract. Lengo will be produced via four initial development wells, a minimum facilities platform, a 65 km pipeline to shore and an onshore receiving facility for gas dehydration.

EXPLORATION

Two exploration wells were completed in 2014, one each in G11/48 and G10/48, with both wells marking our final commitments in the third exploration phase of the licences:

- In G11/48, the *Atwood Orca* jack-up rig commenced drilling of the Rojana-1 well on 23 June 2014. The well reached a total depth at 4,916 feet measured depth ("MD"), or -4,126 feet true vertical depth subsea ("TVDSS"). No significant hydrocarbon shows were detected in the target reservoirs. Water depth at the well location was 230 feet; and
- In G10/48, the *West Cressida* jack-up rig commenced drilling of the Mancharee-1 well on 8 August 2014. The well reached a total depth at 12,205 feet MD or -10,460 feet TVDSS. Gas shows were encountered at several levels but no significant pay zones were identified. Water depth at the well location was 170 feet.

The Mancharee well was in a location that tested our hydrocarbon migration model in the block away from the proven Wassana/Mayura/Niramai trend. The data collected will be incorporated into our geological models to provide direction for further exploration within the block. Apart from the future appraisal of the Niramai and Mayura oil discoveries to test commercial viability for development, there are multiple prospects and leads in G10/48 that we intend to investigate at a later stage once Wassana is producing. Similarly, there remain two discoveries for appraisal – Angun oil and Mantana gas – in G11/48 and several leads that would benefit from 3D seismic acquisition.

We completed, as the operator, four seismic acquisition programs in 2014 in Indonesia, and participated in one non-operated program offshore Bangladesh:

- East Muriah PSC: 1,284 km 2D seismic data;
- Sakti PSC: 1,202 km 2D seismic data and 401 sq. km 3D seismic data;
- Tanjung Aru PSC: 502 sq. km 3D broadband seismic data; and
- SS-11: 3,146 km 2D seismic data.

In addition, we continued preparations for a 300 km 2D seismic acquisition program in the Udan Emas PSC onshore West Papua in Indonesia. The remote and lengthy program commenced recording in January 2015 and will run for four to five months. For details on the Udan Emas seismic program see *Spotlight on Indonesia: Rumble in the Jungle* on pages 24–25.



Offshore seismic acquisition

LOOKING AHEAD

Our operated development drilling activity will step up in 2015 with up to 15 wells planned for the Wassana project and two new wells scheduled in the Bangora field, where we expect an existing well to be shut-in at some point. We have also scheduled up to two exploration/appraisal wells in the G6/48 licence in the Gulf of Thailand where the Rossukon oil discovery is located.

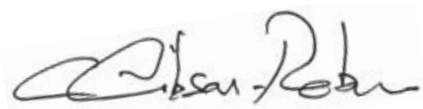
In non-operated blocks, up to 60 development wells will be drilled in B8/32 and B9A in 2015 and one new platform is due to be installed, while in G11/48 there are 19 development wells to be drilled in the Nong Yao field.

Our activities in Cambodia in 2015 are largely dependent upon the pace of our negotiations with the government to obtain approval for the Apsara development plan and the fiscal terms. Similar to the Wassana project, we will lay as much groundwork as possible to be in a position to respond rapidly when all agreements are in place. We expect that first oil could be achieved 24 months after FID is declared between the joint-venture partners.

Our exploration activities in 2015 are largely discretionary and therefore we reserve the flexibility to review our program depending on rates for rigs and associated services, the oil price and activities in other areas of the company. We are enthused by preliminary interpretation of some of the seismic data acquired in 2014, specifically in the Sakti and Tanjung Aru PSCs, and will keep an opportunistic approach to exploration drilling should a rig become available at the right time and cost.

Seismic acquisition in 2015 will focus on the Udan Emas PSC and on Vietnam, where we continue to build our geological models for the Block 105, Block 115 and Block 120 exploration areas.

Overarching all that we do will be vigilance on EHSS. The build-up of manpower in 2014 is now complete. Although we have fully independent offices in our countries of operation, our project management and drilling teams are universal and will move between development projects. This provides not only efficiencies in costs, but continuity in EHSS behaviour and performance.



CHRIS GIBSON-ROBINSON

Executive Director, Director Exploration & Production

28 February 2015

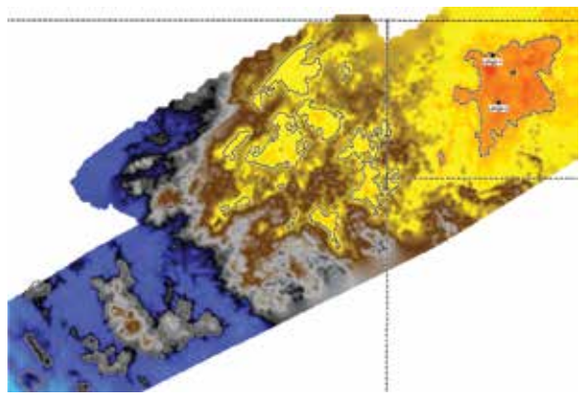
DISCOVERING HIDDEN POTENTIAL IN INDONESIA

Situated immediately west of the Lengo gas development is the Sakti PSC, which was awarded to KrisEnergy in February 2014 through an Indonesian JSA.

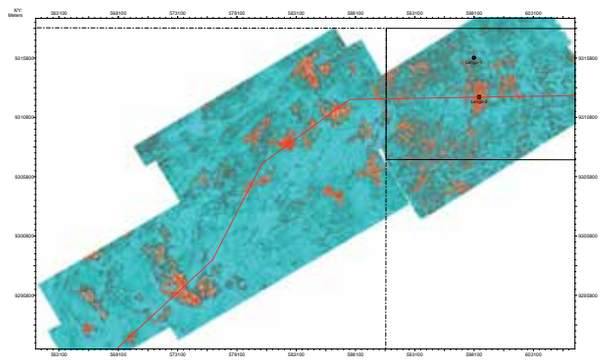
Prior to drilling the successful Lengo-2 appraisal well that led to the approval of the Lengo field development, our Indonesian geologists and geophysicists speculated that several other similar gas accumulations could exist to the west of Lengo. It was believed that the same Kujung Limestone reservoir tested in Lengo was present and trapping gas within the Sakti block. If correct, there could be valuable tie-back opportunities to the Lengo development.

KrisEnergy's technical team gained a keen understanding of the geology and geophysics of the Kujung reservoir from the Lengo drilling experience, but the poor quality of the existing seismic data across the Sakti PSC did not effectively image the reservoir or offer direct detection of gas. A decision was made to expedite the acquisition of a 3D seismic survey upon award of the block and 401 sq. km of 3D seismic data was acquired in October 2014.

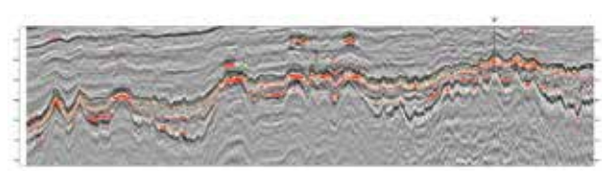
Preliminary results of the 3D survey analysis indicate the Sakti PSC holds the potential for many exploration and appraisal opportunities that could enhance value by leveraging on the Lengo production facilities.



Kujung formation subsurface structure map showing many potential traps for gas that could be tied back to the Lengo facilities.



A 3D seismic attribute extraction map showing a potential direct hydrocarbon indication from the primary Kujung Limestone reservoir interval.



A 3D seismic profile A-A' across the Sakti block to the Lengo field showing a similar seismic response for gas as that seen at Lengo (red highlights). Note the stair-stepping possible gas water contacts observed on the anomalies (dashed lines).

The following reserves and contingent resources tables have been extracted from the qualified person's report dated 31 December 2014 ("QPR"), as prepared by the independent qualified person, NSAI (Texas Board of Professional Engineers Registration No. F-2699). Mr. Scott Frost of NSAI is a Licensed Professional Engineer in the States of Texas (No. 88738) and a member of the Society of Petroleum Engineers and Mr. Allen Evans of NSAI is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1286) and a member of the American Association of Petroleum Geologists.

Please also refer to the Appendix of this Annual Report for the executive summary of the QPR.

Our full QPR is available for inspection at our Singapore office during working hours by shareholders whose names appear in the CDP Registry or our Register of Members. Shareholders who wish to inspect our full QPR should write to KrisEnergy Ltd, 83 Clemenceau Avenue, #10-05 UE Square, Singapore 239920 to request an appointment.

RESERVES

	1P RESERVES			2P RESERVES			3P RESERVES			
	GROSS	WORKING INTEREST		GROSS	WORKING INTEREST		GROSS	WORKING INTEREST		REMARKS
	(mmbbl[1])	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	(mmbbl)	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	(mmbbl)	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	
OIL										
BANGLADESH										
Block 9	0.53	0.16	78	0.84	0.25	9	0.90	0.27	(13)	
THAILAND										
B8/32 and B9A	29.11	1.35	(4)	123.48	5.72	(9)	149.02	6.91	(11)	
G10/48	-	-	-	13.55	13.55	100	21.90	21.90	100	Conversion from contingent resources and increased working interest
G11/48	9.78	2.20	5	12.67	2.85	(16)	16.36	3.68	(29)	Reclassification of 2P to 2C associated with the location of the Nong Yao-3 exploration well
	(bcf[2])	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	(bcf)	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	(bcf)	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	
GAS										
BANGLADESH										
Block 9	188.59	56.58	81	353.88	106.16	11	378.23	113.47	(15)	
INDONESIA										
Bulu PSC	–	–	–	358.80	152.49	100	419.60	178.33	100	
THAILAND										
B8/32 and B9A	146.43	6.79	(2)	709.02	32.86	(15)	881.98	40.88	(16)	Conversion from contingent resources

Reserves are quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterised by development and production status:

Proved reserves ("1P") are 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 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 (together with 1P, "2P") are additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than 1P reserves but more certain to be recovered than possible reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate; and

Possible reserves (together with 1P and 2P, "3P") are additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Contingent resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example,

CONTINGENT RESOURCES

	1C RESOURCES			2C RESOURCES			3C RESOURCES			
	GROSS	WORKING INTEREST		GROSS	WORKING INTEREST		GROSS	WORKING INTEREST		REMARKS
	(mmbbl[1])	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	(mmbbl)	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	(mmbbl)	(mmbbl)	CHANGE FROM PREVIOUS UPDATE (%)	
OIL										
BANGLADESH										
Block 9	0.02	0.01	-	0.11	0.03	-	0.54	0.16	-	
CAMBODIA										
Block A	0.91	0.47	(66)	10.28	5.37	118	18.08	9.45	120	Increased working interest
INDONESIA										
Block A Aceh PSC	1.19	0.50	100	2.27	0.95	100	4.16	1.73	100	Acquisition
Kutai PSC	-	-	-	0.09	0.05	-	0.15	0.08	-	
THAILAND										
G6/48	-	-	-	8.37	2.51	-	20.50	6.15	-	
G10/48	0.45	0.45	309	5.98	5.98	22	10.22	10.22	27	Conversion to reserves and increased working interest
G11/48	2.31	0.52	767	3.95	0.89	493	25.73	5.79	22	
	(bcf[2])	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	(bcf)	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	(bcf)	(bcf)	CHANGE FROM PREVIOUS UPDATE (%)	
GAS										
BANGLADESH										
Block 9	6.08	1.82	-	27.68	8.30	-	128.95	38.69	-	
INDONESIA										
Block A Aceh PSC	1129.19	470.49	100	1477.77	615.74	100	2007.63	836.51	100	Acquisition
Bulu PSC	-	-	(100)	-	-	(100)	-	-	(100)	Conversion to reserves
East Muriah PSC	-	-	-	19.70	9.85	-	48.87	24.43	-	
Kutai PSC	-	-	-	75.70	41.33	-	117.45	64.13	-	
Tanjung Aru PSC	-	-	-	110.51	47.52	-	155.81	67.00	-	
THAILAND										
G11/48	4.92	1.11	-	14.84	3.34	-	26.08	5.87	-	

projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

In the "low estimate" scenario of contingent resources ("1C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90%;

In the "best estimate" scenario of contingent resources (together with 1C, "2C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 50%; and

In the "high estimate" scenario of contingent resources (together with 1C and 2C, "3C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 10%.

Contingent resources are classified as development pending when there is a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan.

Contingent resources are classified as development unclarified when there is a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal and/or evaluation activities are required to clarify the potential for eventual commercial development.

[1] mmbbl refers to millions of barrels
[2] bcf refers to billions of cubic feet

STRATEGY & PORTFOLIO





STRATEGY & PORTFOLIO



RICHARD LORENTZ

Director Business Development

KrisEnergy is a fast-growth E&P company and our portfolio continues to expand and evolve. This constant evolution was highlighted by the conversion of 39 mmboe of 2C resources to 2P reserves at the end of 2014, reflecting progress in two KrisEnergy-operated development projects – Wassana and Lengo. Our focus in the coming 36 months will be to execute on our development projects to increase production, and therefore cash flow, and to increase our reserves base.

Our approach to building a sustainable and successful upstream oil company is to assemble a multi-asset portfolio diversified across fiscal and regulatory regimes, mixed between oil and gas reserves and resources, and active across each stage of the exploration-to-production life cycle. Not least, flexibility and balance in our capital structure is as important as disciplined portfolio management.

The rollercoaster ride of the past year has underpinned our belief in the portfolio strategy.

For KrisEnergy, 2014 was a transformational year in which we made solid progress operationally, strategically and in our growth aspirations. We doubled our production as well as reserves and resources; we executed three significant acquisitions; we were awarded three exploration assets; and we undertook debt refinancing that increased our borrowings while reducing the effective cost of debt.

But the oil markets and investor confidence in the upstream sector were dismal. The oil price drop surprised many observers and companies both in its speed and magnitude. KrisEnergy is not immune to such changes but there are several features of our portfolio that reduce our exposure compared with others in the industry:

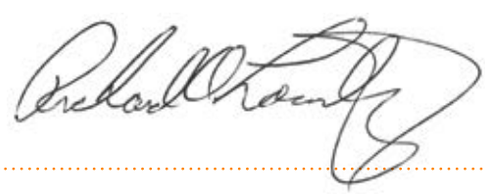
- **Striking a balance between oil and gas:** Gas is highly prized in the markets of Southeast Asia, with infrastructure developing around the region to transport this increasingly important source of fuel further afield from the site of production. Gas also has the advantage of being sold under long-term contracts that are either at fixed levels or adjusted once or twice a year, so it is less volatile than the price of oil on spot markets;
- **Diversifying fiscal regimes:** Our 19 assets span five countries with various fiscal regimes. We benefit from the stability of the production sharing contract arrangement in times of market volatility and downswings, and from the tax royalty environment when prices are rising or are stable at higher levels;



Inspection at one of the production wellheads in the Bangora gas field in Bangladesh

- **Testing commercial thresholds:** Many of our current development projects were acquired shortly after KrisEnergy was established in 2009. Our assessment of the commercial viability of these projects was based on a lower oil price than the US$100+/bbl that prevailed between 2011 and 2014;
- **Flexibility in operations:** We have little by way of firm commitment or obligation under our exploration licence agreements over the next three years and therefore we are able to fast-track or defer activities to optimise operations and efficiencies and control capital expenditures; and
- **Operating control:** Our development portfolio was strengthened in 2014 with the acquisition of increased working interests in G10/48 and Cambodia Block A. Importantly the operatorship of both licences was transferred to KrisEnergy, giving us control over the work program, the timing of operational activities as well as oversight of expenditure. These two projects along with the non-operated Nong Yao development in G11/48, form the backbone of our Gulf of Thailand core area with Nong Yao and Wassana on target to produce first oil in the second half of the year.

Uncertainty continues in early 2015 over when and at what levels global oil markets will stabilise. Likewise, the impact of any benefit from the associated decline in costs for third-party services and equipment and materials is not yet quantifiable. As part of our risk mitigation, we run sensitivity tests on our economic models to ensure we remain in safe territory and we will continue to rigorously manage our portfolio through both acquisition and divestment.



RICHARD LORENTZ

Executive Director, Director Business Development

28 February 2015

OUR PORTFOLIO





SINGAPORE ENERGY HUB

COUNTRY FACTS

Capital and largest city	Singapore
Official languages	English Malay Mandarin Tamil
Ethnic groups	Chinese Malay Indian Eurasian
Total area	**700 sq. km**
Population	
2013	5,399,200
GDP (PPP)	**2013 estimate**
Total	US$425.3 billion
Per capita	US$78,762
Currency	**Singapore dollar (SGD)**

KRISENERGY

Office	83 Clemenceau Avenue #10-05, UE Square Singapore 239920

Note:
All country facts compiled from World Bank

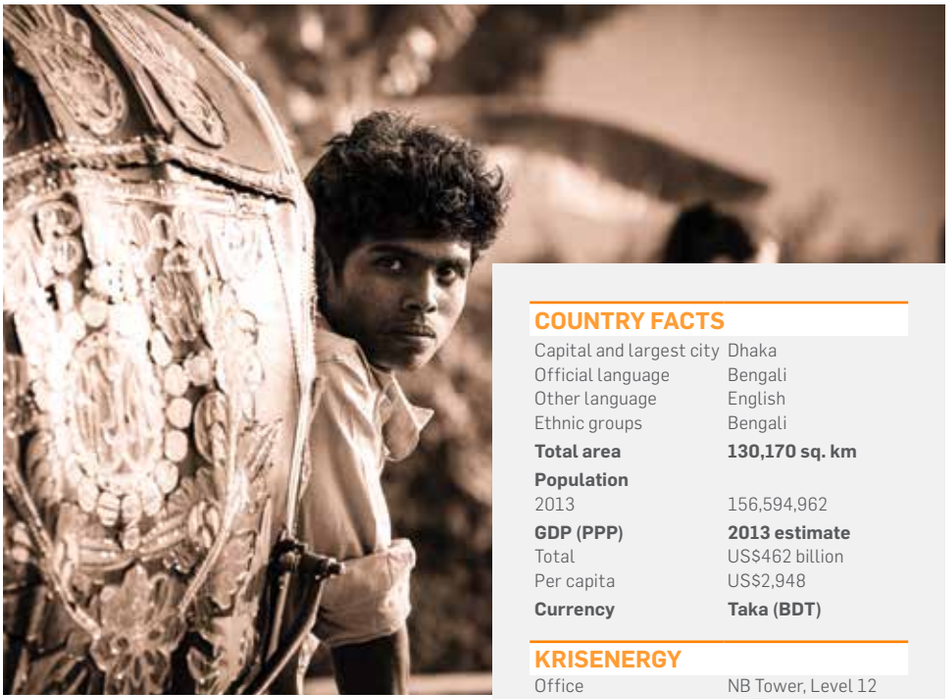
As at 28 February 2015, KrisEnergy holds working interests in 19 contract areas in five countries.

We are mindful of managing risk. Our approach is to build a portfolio of assets across each stage of the E&P life cycle and to spread our exposure to political and fiscal risks by operating in multiple countries with different taxation regimes and regulations.

Our assets are largely in shallow waters in well-explored geological basins. We operate 12 of our 19 assets giving us control of the work programs and budget and therefore the flexibility to optimise operations such as drilling and seismic acquisition.

We aim to balance our reserves, resources and production between oil and gas. Commercial oil discoveries are quicker to develop and sell into a ready international spot market at a higher value than the gas equivalent, but the latter is generally sold under long-term supply contracts in Asia and less vulnerable to the volatility of global benchmark oil prices.

Producing assets provide cash flow with which we explore for hydrocarbons and subsequently appraise and develop our discoveries. We aggressively seek new acquisition opportunities across the E&P cycle but remain committed to maintaining rigorous technical, operational and commercial selection standards. Likewise, the divestment of assets is also critical to portfolio management.



COUNTRY FACTS

Capital and largest city	Dhaka
Official language	Bengali
Other language	English
Ethnic groups	Bengali
Total area	**130,170 sq. km**
Population	
2013	156,594,962
GDP (PPP)	**2013 estimate**
Total	US$462 billion
Per capita	US$2,948
Currency	**Taka (BDT)**

KRISENERGY

Office	NB Tower, Level 12 40/7, North Avenue, Gulshan 2, Dhaka 1212

BANGLADESH

One of the world's most densely populated countries, Bangladesh occupies much of the massive and fertile Ganges-Brahmaputra river delta above the Bay of Bengal. Increasingly, Bangladesh's economy is buoyed by overseas remittances and the garment industry. Bangladesh is now one of the biggest exporters of ready-made garments and although the country's hydrocarbon industry is dominated by natural gas, it faces critical supply shortages partly as a result of rising domestic demand from the burgeoning garment, fertiliser and power sectors.

KrisEnergy holds one onshore licence, Block 9, where the producing Bangora gas field is located, and one offshore shallow water exploration block, SS-11.

BLOCK 9

We hold a 30% operated working interest in Block 9, through our acquisition of Tullow Bangladesh Ltd, which completed in December 2013.

Block 9 covers 1,770 sq. km over the Bangora Lalmai anticline onshore Bangladesh, approximately 50 km east of Dhaka. It contains the Bangora gas producing field and the Lalmai gas accumulation, discoveries made in 2004 by the Bangora-1 ("B-1") and Lalmai-3 exploration wells, respectively. Both wells tested dry gas from several sandstone units within the Late Miocene Upper Bhuban formation, which provides the main reservoir objective in the Surma Basin.

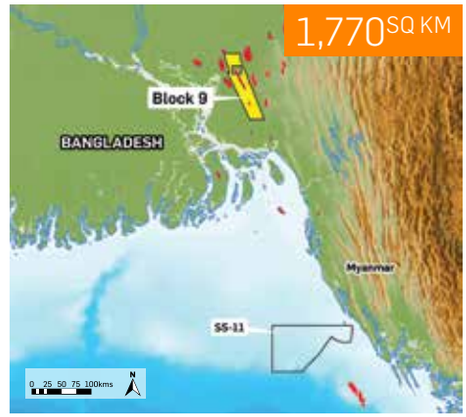
Bangora commenced production in 2006 from the B-1 well under a long-term flow test. Subsequently three additional development wells – B-2, B-3 and B-5 – were put into production with gas processed through the Bangora central processing facility, located in the southern area of the block in Muradnagar Upazilla in the Comilla District. Sales gas is injected directly into the national grid transmission network through a sales gas transfer line. The associated condensate is trucked to nearby refineries.

Two well workovers were conducted in 2013 to replace production tubing with corrosion-resistant chrome tubing. Upgrading of the Bangora field operation continued in 2014 with the commissioning of three compressors and the fabrication and installation of a condensate storage tank and a condensate loading system.

Average gross gas production in 2014 was 107.7 mmcfd. Gross cumulative gas production at Bangora as at 31 December 2014 was 285 billion cubic feet ("bcf") and the NSAI estimate for gross remaining 2P reserves as at 31 December 2014 was 353.9 bcf of gas and 0.8 million barrels of condensate.

In 2015, KrisEnergy intends to drill two development wells, B-6 and B-7, one of which will eventually replace the B-1 well, which is expected to be converted to a water injection well at a later stage.

Block 9 also contains additional upside potential including contingent and prospective resources within a lead portfolio along the crest and flanks of the anticline. Most of these leads are amplitude driven showing sand prone geometries. The main risks associated with these leads are considered to be the seal presence in the shallower leads and overpressure in the deeper leads. We intend to review all seismic data in the block to identify future drilling targets.



BLOCK 9
ONSHORE BANGLADESH
PRODUCTION & EXPLORATION

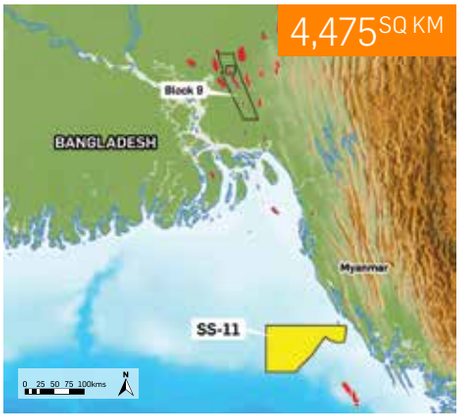
PARTNERS

KrisEnergy (operator)	30%
Niko Resources	60%
BAPEX	10%

LOCATION
Onshore Bangladesh over Surma Basin

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
RESERVES			
1P	0.2	56.6	9.6
2P	0.3	106.2	18.0
3P	0.3	113.5	19.2
CONTINGENT RESOURCES			
1C	0.0	1.8	0.3
2C	0.0	8.3	1.4
3C	0.2	38.7	6.6



SS-11 OFFSHORE BANGLADESH EXPLORATION

PARTNERS

KrisEnergy	45%
Santos (operator)	45%
BAPEX	10%

LOCATION
Bay of Bengal over Bengal Fan

WATER DEPTHS
200 – 1,500 metres

KrisEnergy became a 45% non-operating working interest partner in the SS-11 exploration block in March 2014 through a direct award from the Government of the People's Republic of Bangladesh. The PSC has an initial five-year term, with an associated work commitment of the acquisition and processing of 1,893 km 2D seismic data and 300 sq. km 3D seismic data, and the drilling of one exploration well.

SS-11 covers 4,475 sq. km in the Bay of Bengal over the Bengal Fan, the world's largest submarine fan at approximately 3,000 km long and 1,000 km wide with a maximum thickness of 16.5 km. The fan was formed by sediment supplied by the Ganges and Brahmaputra River, through delta systems and a series of submarine canyons out into the Bay of Bengal. Drilling to date has been confined largely to the margins of the basin, with negligible drilling in the central Bay region. No wells have been drilled within the current boundary line of SS-11, the majority of which lies in shallow waters up to 200 metres depth.

Existing geological and geophysical data comprises 1970s widely spaced vintage seismic data of generally poor quality. Prior to the award of SS-11 in 2014, no modern – post 1990 – 2D or 3D seismic had been acquired in the area, apart from a small 3D survey over the Tekneft anticlinal structure in Block 10.

The SS-11 joint-venture partners undertook a 3,146 km 2D seismic acquisition program in December 2014 and January 2015. The data is being processed for interpretation and identification of leads and prospects ahead of a planned 3D seismic program in 2015.



COUNTRY FACTS	Thailand	Cambodia
Capital and largest city	Bangkok	Phnom Penh
Official language	Thai	Khmer
Ethnic groups	Thai Chinese Others	Khmer Vietnamese Chinese Others
Total area	**510,890 sq. km**	**176,520 sq. km**
Population		
2013	67,010,502	15,135,169
GDP (PPP)	**2013 estimate**	**2013 estimate**
Total	US$965 billion	US$46 billion
Per capita	US$14,394	US$3,041
Currency	**Baht (THB)**	**Riel (KHR)**

KRISENERGY

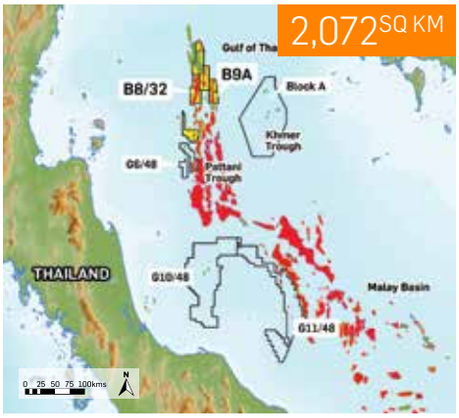
Office	Thailand: 7F Athenee Tower, No. 63 Wireless Road, Lumpini, Pathumwan, Bangkok 10330 Cambodia: No. 28, Street 310, Sangkat Boeung Keng Kang 1, Khan Chamcar Monn, Phnom Penh, P.O. Box 1619

GULF OF THAILAND/ OFFSHORE CAMBODIA

The Gulf of Thailand covers approximately 320,000 sq. km and borders Cambodia, Malaysia, Thailand and Vietnam. The majority of Thailand's oil and gas reserves have been discovered in the Gulf of Thailand, which is also the location of Cambodia's first potential oil field development.

The area is composed of a series of geological basins in which numerous faults provide structural closures for hydrocarbon accumulation. A typical oil and gas field has multiple fault blocks with oil and/or gas trapped in multiple reservoirs.

KrisEnergy's portfolio in Thai waters comprises the B8/32 and B9A oil and gas producing fields, the G10/48 and G11/48 development blocks, which are scheduled to commence oil production in the second half of 2015, and the G6/48 licence, where the Rossukon oil discovery requires appraisal. The company is the operator of Cambodia Block A across the maritime border in Cambodia waters, where the Apsara series of oil discoveries are pending development.



B8/32 & B9A
PRODUCTION, DEVELOPMENT & EXPLORATION

PARTNERS

KrisEnergy	4.63%
Chevron (operator)	51.66%
PTTEP	25.00%
MOECO	18.71%
Palang Sophon	2.00%

LOCATION
Northern Pattani Basin

WATER DEPTHS
42 – 113 metres

WORKING INTEREST

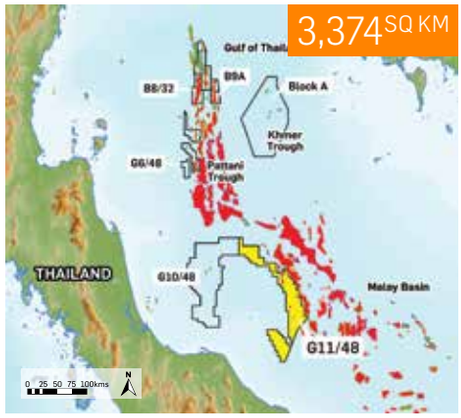
	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
RESERVES			
1P	1.4	6.8	2.5
2P	5.7	32.9	11.2
3P	6.9	40.9	13.7

Several producing fields are located within the B8/32 and B9A complex, the largest of which is Benchamas, which also processes production from the Maliwan and North Jarmjuree areas. Oil production is offloaded from the FSO *Benchamas Explorer*.

The second major producing area is Tantawan where production is processed on the floating production, storage and offloading vessel *Tantawan Explorer*, which also processes the crude oil stream from the Rajpruek field in B9A. A third producing area, Chaba, commenced production in 2009.

Due to the compartmentalised geology of the Gulf of Thailand, maintaining production rates in the fields is dependent upon the continual drilling of new development wells to offset reserves depletion. In 2014, 55 development wells were drilled and two new production platforms were brought on stream. In addition, in-fill drilling resulted in the resumption of production at three platforms. As at 31 December 2014, there were 41 platforms and 250 producing wells in the B8/32 and B9A complex and gross cumulative production was 417 mmboe with gross 2P reserves of 709.0 bcf of gas and 123.5 million barrels of oil remaining.

In 2015, up to 60 development wells are scheduled to be drilled and one new production platform is anticipated to commence operation.



G11/48
NEAR-TERM PRODUCTION, APPRAISAL & EXPLORATION

PARTNERS

KrisEnergy	22.5%
Mubadala (operator)	67.5%
Palang Sophon	10.0%

LOCATION
Southern margin of Pattani Basin and northwest margin of Malay Basin

WATER DEPTHS
Up to 75 metres

WORKING INTEREST

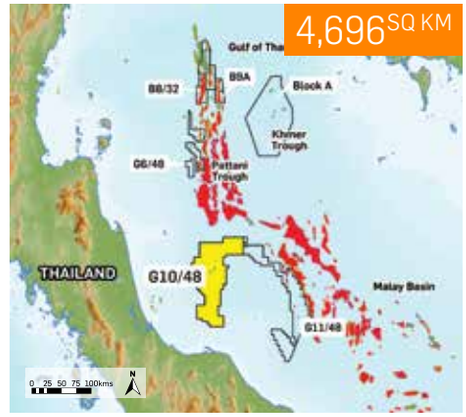
	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
RESERVES			
1P	2.2	0.0	2.2
2P	2.9	0.0	2.9
3P	3.7	0.0	3.7
CONTINGENT RESOURCES			
1C	0.5	1.1	0.7
2C	0.9	3.3	1.4
3C	5.8	5.9	6.8

G11/48 contains the Nong Yao and Angun oil discoveries and the Mantana gas accumulation, which were drilled in a single exploration campaign in 2009. The production area application ("PAA") for the Nong Yao development project was approved in late 2012. The development consists of 19 wells, a wellhead processing platform and a minimum facility wellhead platform with the export of crude oil via FSO vessel. The facilities will have a production capacity of up to 15,000 bopd and a processing capacity of 30,000 barrels of fluids per day. First oil is expected in the second half of 2015.

The engineering, procurement, construction, installation and commissioning contract for the Nong Yao production and processing facilities was awarded to Nippon Steel and Sumikin Engineering Co Ltd in January 2014. As at 28 February 2015, fabrication of the two platforms was 100% complete.

G11/48 also holds a number of mapped drillable prospects as well as leads for potential upside exploration. In June 2014, the joint-venture partners drilled the Rojana-1 exploration well, the final exploration commitment well under the G11/48 petroleum concession. The well reached a total depth at 4,916 feet MD (1,498 metres MD), or -4,126 feet TVDSS. No significant hydrocarbon shows were detected in the target reservoirs and the well was plugged.

The government of the Kingdom of Thailand approved in May 2014 the farm-out of a 10% working interest in G11/48 to Palang Sophon Ltd as a Thai participant (being a Thai national or a Thai company majority owned by Thai nationals) as required under the petroleum concession once a production area has been defined. Following the farm-out agreement, KrisEnergy's working interest in G11/48 reduced to 22.5% from 25%.



G10/48
NEAR-TERM PRODUCTION, APPRAISAL & EXPLORATION

PARTNERS[1]

KrisEnergy (operator)	100%

LOCATION
Southern Pattani Basin

WATER DEPTHS
Up to 60 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
RESERVES			
1P	0.0	0.0	0.0
2P	13.6	0.0	13.6
3P	21.9	0.0	21.9
CONTINGENT RESOURCES			
1C	0.5	0.0	0.5
2C	6.0	0.0	6.0
3C	10.2	0.0	10.2

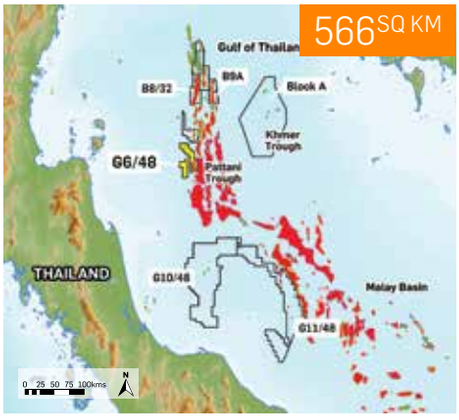
KrisEnergy secured a 25% working interest in G10/48 in 2009 and in 2014 acquired the remaining 75% and took over operatorship of the block, which holds the Wassana, Niramai and Mayura oil discoveries.

Wassana will be the first oil production from G10/48 and is slated to go on stream in the second half of 2015 and reach a gross plateau rate at 10,000 bopd. Official approval for the Wassana PAA was received from the Thai regulators in February 2015.

The development comprises the *MOPU Ingenium*, and up to 15 development wells producing to the *Rubicon Vantage* FSO, which is connected to the MOPU via a CALM buoy. All key components for the development have been secured and are in various stages of refurbishment or construction. The *Key Gibraltar* jack-up rig has been contracted to drill the development wells. For a brief description of the development program, see *Spotlight on Thailand: Wassana Oils Growth Engine* on pages 16–17.

The Niramai and Mayura discoveries require further appraisal to mature into development projects and G10/48 contains numerous additional prospects with exploration upside potential. In August 2014, the Mancharee-1 exploration well was drilled, the final commitment well under the petroleum concession. Mancharee-1 reached a total depth at 12,205 feet MD (3,720 metres MD) or -10,460 feet TVDSS. No significant pay zones were identified and the well was plugged. Further exploration and appraisal drilling is planned.

[1] On 5 February 2015, we completed the sale of 14.67% shareholding interest in KrisEnergy Management Ltd to Palang Sophon. KrisEnergy Management Ltd holds 100% of KrisEnergy G10 (Thailand) Ltd, which holds 75% working interest in G10/48. Our wholly owned entity, KrisEnergy (Gulf of Thailand) Ltd, holds the remaining 25% working interest in, and operatorship of G10/48



G6/48
APPRAISAL & EXPLORATION

PARTNERS

KrisEnergy (operator)	30%
Mubadala	30%
Northern Gulf Petroleum	40%

LOCATION
Karawake Basin on western margin of Pattani Basin

WATER DEPTHS
60 – 70 metres

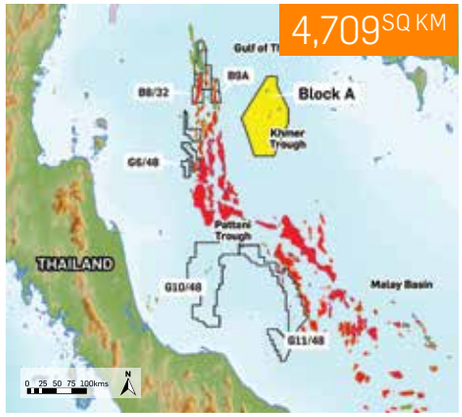
WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
CONTINGENT RESOURCES			
1C	0.0	0.0	0.0
2C	2.5	0.0	2.5
3C	6.2	0.0	6.2

G6/48 became KrisEnergy's first operated licence in the Gulf of Thailand in May 2014 following government approval for the company's farm-in transaction.

The appraisal block is located north of the G10/48 development block and south of the B8/32 producing area over the Karawake Basin, a small but deep tertiary sub-basin situated immediately west of the prolific Pattani Basin and partially separated from it by the Dara High. In 2009, the Rossukon-1 exploration well encountered 31 feet of net oil pay and 19 feet of net gas pay and tested 851 bopd from a single zone.

Seven additional leads have been identified around the Rossukon discovery along the eastern and western flank of the Karawake kitchen. Analysis of the extensive 2D and 3D seismic data covering the block has identified two drilling locations and it is anticipated that up to four exploratory wells will be drilled in the first half of 2015 using the *Key Gibraltar* jack-up rig.



CAMBODIA BLOCK A
DEVELOPMENT PENDING & EXPLORATION

PARTNERS[2]

KrisEnergy (operator)	55%
MOECO	30%
GS Energy Corporation	15%

LOCATION
Khmer Basin

WATER DEPTHS
50 – 80 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
CONTINGENT RESOURCES			
1C	0.5	0.0	0.5
2C	5.4	0.0	5.4
3C	9.5	0.0	9.5

A 25% joint-venture partner in Cambodia Block A since 2010, KrisEnergy acquired in October 2014 the entire issued and paid up share capital of Chevron Overseas Petroleum (Cambodia) Ltd ("COPCL"), which held a 30% interest and the operatorship of Cambodia Block A. COPCL has been renamed as KrisEnergy (Apsara) Ltd and the company's combined working interest in the block is 55%.

Cambodia Block A overlays the Khmer Basin, offshore in Cambodian waters and is located to the east of the Pattani Trough within the central area of the Gulf of Thailand. Extensive exploration work in the Cambodia Block A licence since the 1970s resulted in 26 wells being drilled with 23 encountering oil and/or gas.

KrisEnergy, as operator, along with the joint-venture partners, is working closely with the Cambodian authorities to agree the terms of the production permit and petroleum agreement for the contract area. Once these have been agreed, the joint-venture partners will be able to declare FID. Production from the initial phase of the Apsara development is anticipated to start approximately 24 months after FID is declared.

Phase 1A of the Apsara project includes 20 development wells from a single platform producing to a production barge for processing and then stored in an offshore storage vessel prior to commercial sales. Production from the initial single platform is expected to peak at approximately 8,000 bopd. Once Phase 1A is on stream, we envisage a period of monitoring reservoir performance before commencing on Phase 1B of three additional platforms producing to the Phase 1A facilities.

The Cambodian Ministry of Mines and Energy ("MME"), the successor agency to the Cambodian National Petroleum Authority) intends to exercise its right to acquire a 5% working interest in Cambodia Block A, which when completed will reduce KrisEnergy's combined holdings to 52.25%.

[2] Before 5% transfer of working interest to MME





INDONESIA

Indonesia is one of the top oil and gas producing nations in Asia and has a rich history dating back to the late 1800s when the production of crude oil first began on the island of Sumatra. The world's largest archipelago straddles the equator and runs through three time zones, spanning roughly 5,000 km. Its many thousands of islands overlay an estimated 128 geological basins with only about one-third having been extensively explored.

KrisEnergy holds interests in eight production sharing contracts in Indonesia in four core areas: East Java Sea (Bulu PSC, East Muriah PSC and Sakti PSC); Makassar Strait (Kutai PSC and Tanjung Aru PSC); North Sumatra (Block A Aceh PSC and East Seruway PSC); and onshore West Papua (Udan Emas PSC).

COUNTRY FACTS

Capital and largest city	Jakarta
Official language	Bahasa Indonesia
Ethnic groups	Javanese Sundanese Malay Madurese Others
Total area	**1,811,570 sq. km**
Population	
2013	249,865,631
GDP (PPP)	**2013 estimate**
Total	US$2.4 trillion
Per capita	US$9,561
Currency	**Rupiah (IDR)**

KRISENERGY

Office	Talavera Office Park 3rd Floor, Jln. Let. Jend. TB. Simatupang Kav. 22-26 Cilandak Jakarta 12430

East Java Sea

The East Java Basin is dominated by two principal structural trends: a northeastly extensional regime represented by horst blocks and intervening half-grabens which have been overprinted by an east-west compressional trend. The stratigraphic section comprises Eocene-Early Miocene transgressive clastics with carbonate developments on structural highs overlain with regressive clastics.

KrisEnergy operates three PSCs in the East Java Sea, two – Bulu and East Muriah – contain gas discoveries at various stages of development or appraisal. The third contract area, Sakti, is an exploration block, which was awarded to KrisEnergy as the operator in February 2014.

These three assets form the company's gas aggregation strategy for sales into the thriving industrial heartland onshore Java, where gas demand is steadily increasing for power generation and fertiliser and petrochemical plants.



BULU PSC
NEAR-TERM PRODUCTION

PARTNERS

KrisEnergy (operator)	42.5%
AWE Ltd	42.5%
Pt Satria Energindo	10.0%
Pt Satria Wijayakusuma	5.0%

LOCATION
East Java Sea

WATER DEPTHS
50 – 60 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
RESERVES			
1P	0.0	0.0	0.0
2P	0.0	152.5	25.4
3P	0.0	178.3	29.7

The Bulu PSC comprises three separate areas – A, B and C – of which Bulu A contains the Lengo gas accumulation, which was discovered by the Lengo-1 exploration well in 2008 and delineated by the Lengo-2 appraisal well in 2013. Data from the Lengo-2 well increased the 2C resource estimates for the discovery and demonstrated the Lengo accumulation to be commercially viable for development.

The development plan for the Lengo gas field was approved by the Indonesian authorities in late 2014 and resulted in the conversion of 25.4 mmboe of working interest 2C resources to 2P reserves.

The project will entail drilling four initial development wells each up to 7,000 feet in length and reaching a vertical depth of approximately 2,500 feet, fabrication and installation of an unmanned wellhead platform and the laying of a 20-inch, 65 km export pipeline to transport the gas to shore. Production is anticipated to commence 24 months after the joint-venture partners declare FID and is expected to plateau at 70 mmcfd.



EAST MURIAH PSC
DEVELOPMENT PENDING

PARTNERS

KrisEnergy (operator)	50%
AWE Ltd	50%

LOCATION
East Java Sea

WATER DEPTHS
50 – 65 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
CONTINGENT RESOURCES			
1C	0.0	0.0	0.0
2C	0.0	9.9	1.6
3C	0.0	24.4	4.1

The East Muriah PSC is adjacent to the eastern boundary of the Bulu A area and contains the East Lengo gas accumulation, which was discovered in 2010.

KrisEnergy completed a 1,284 km 2D seismic acquisition program in February 2014, designed to help in the identification of the drilling location for an appraisal well to delineate the East Lengo structure. If appraisal is successful and proves East Lengo volumes to be viable for development, the appraisal well would be tied-back to the Lengo gas production facilities, located 15 km away in the Bulu PSC.

In addition, work on further leads and prospects defined on the new seismic is ongoing.



SAKTI PSC
EXPLORATION

PARTNERS

KrisEnergy (operator)	95%
Golden Heaven Jaya Ltd	5%

LOCATION
East Java Sea

WATER DEPTHS
50 – 60 metres

KrisEnergy was awarded as operator a 95% working interest in the Sakti PSC in February 2014. The exploration block is adjacent to the KrisEnergy-operated Bulu and East Muriah PSCs, where the company is undertaking development of the Lengo gas field and appraisal of the East Lengo gas accumulation, respectively.

The Sakti PSC has an initial three-year term and an associated work commitment of 1,200 km 2D seismic acquisition and a single well. To date, the 2D seismic commitment has been fulfilled along with the acquisition of an additional 400 sq. km 3D seismic data. Both of the seismic programs were completed in the fourth quarter of 2014 and the data are undergoing processing and interpretation. Initial results are encouraging and a number of Lengo equivalent leads are under review. For details of Sakti 3D seismic see *Discovering Hidden Potential in Indonesia* on page 29.

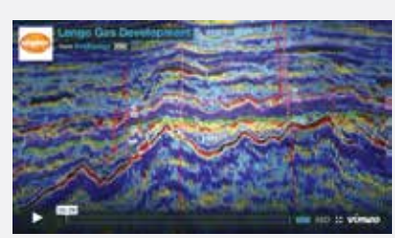
Depending on the availability of drilling rigs and services, the Sakti exploration commitment well is planned to be drilled in 2015 or 2016.

VIDEO

LENGO

http://krisenergy.com/videos/lengo/

Scan the QR code to watch the video



Makassar Strait

The Makassar Strait runs between the islands of Kalimantan and Sulawesi, joining the Celebes Sea at the northern end while to the south it meets the Java Sea. It is one of the most prolific hydrocarbon producing areas in Indonesia.



KUTAI PSC
DEVELOPMENT PENDING & APPRAISAL

PARTNERS

KrisEnergy (operator)	54.6%
Salamander Energy	23.4%
Orchid Kutai ltd	22.0%

LOCATION
Mahakam River delta, Makassar Strait

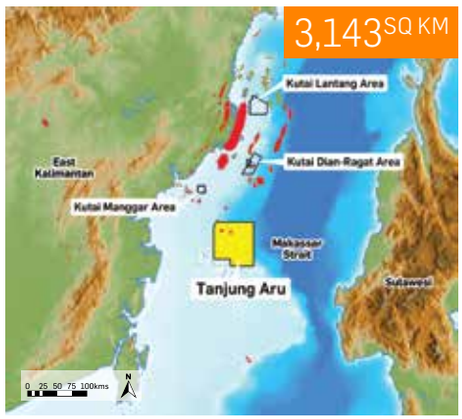
WATER DEPTHS
50 – 90 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
CONTINGENT RESOURCES			
1C	0.0	0.0	0.0
2C	0.1	41.3	6.9
3C	0.1	64.1	10.8

The Kutai PSC is centrally located within the Kutai Basin, offshore in the Mahakam River delta. The block comprises three separate areas totalling 944 sq. km following approval of a final relinquishment in January 2015 under the terms of the Indonesian licensing regulations.

The Kutai PSC contains the Mangkok and Dambus gas accumulations discovered in 2001 and 2010, respectively, and the Tayum discovery drilled in 2013. A further exploration well would be required in order to progress the plan of development for submission to the Indonesian authorities. The current development concept entails re-drilling the discovery wells and installing single-well support structures, with production tied back to a platform at an adjacent field.



TANJUNG ARU PSC
DEVELOPMENT UNCLARIFIED & EXPLORATION

PARTNERS

KrisEnergy (operator)	85%
Natuna Ventures Pte Ltd	15%

LOCATION
Southern edge of Kutai Basin, Makassar Strait

WATER DEPTHS
20 metres to over 1,000 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL(mmboe)
CONTINGENT RESOURCES			
1C	0.0	0.0	0.0
2C	0.0	47.5	7.9
3C	0.0	67.0	11.2

In 2014, Neon Energy withdrew its participation in the Tanjung Aru PSC and its 42% working interest was transferred to KrisEnergy, as operator of the exploration block. The completion of the transfer is pending government approval, which once received, will increase KrisEnergy's working interest in the block to 85% from 43%.

Three exploration wells have been drilled in the current outline of the Tanjung Aru PSC, of which two – Halimun-1 and Papandayan-1 – encountered gas. Work has been undertaken to integrate existing 2D and 3D seismic interpretations and run petrophysical analysis of the wells to review the volumetrics of the discoveries. In March 2014, a 502 sq. km 3D broadband seismic acquisition program was completed to identify additional prospects and leads. Processing and interpretation of the seismic data is ongoing.

In line with the Indonesian licensing regulations governing the end of initial three-year exploration period, the authorities approved the relinquishment of 25% of the gross acreage of the contract area in February 2015 leaving a remaining area of 3,143 sq. km.



Sumatra

Sumatra is the most prolific hydrocarbon producing region in Indonesia and is home to the giant Duri steamflood oil development and the Minas oil field, the largest oil field to be discovered in Southeast Asia.

In July 2014, KrisEnergy acquired through a corporate acquisition a non-operated working interest in the Block A Aceh PSC onshore in North Sumatra, where a number of gas discoveries are pending development and/or appraisal. To the east, offshore in the Malacca Strait, the company operates the East Seruway exploration block.

BLOCK A ACEH

In June 2014, KrisEnergy signed an agreement to acquire Premier Oil Sumatra (North) B.V., which held a 41.6666% non-operated working interest in the Block A Aceh PSC. The transaction was completed in January 2015.

Block A Aceh was historically an oil producing area onshore northeast Sumatra. Oil production ceased in 2001 and the current focus is on commercialisation of gas resources; these include accumulations at Alur Rambong, Alur Siwah and Julu Rayeu, for which a plan of development was approved in 2007. These three accumulations account for 30.4 mmboe of working interest 2C resources in the development pending category. Two other discoveries – Matang and the high-carbon dioxide Kuala Langsa – have an associated 73.2 mmboe working interest 2C resources in the development unclarified category and are also located in the block.



BLOCK A ACEH PSC
DEVELOPMENT PENDING, APPRAISAL & EXPLORATION

PARTNERS

KrisEnergy	41.66%
Medco (operator)	41.66%
Japex Block A Ltd	16.67%

LOCATION
Onshore Sumatra over North Sumatra Basin

WATER DEPTHS
25 – 60 metres

WORKING INTEREST

	OIL (mmbo)	GAS (bcf)	TOTAL (mmboe)
CONTINGENT RESOURCES			
1C	0.5	470.5	78.9
2C	1.0	615.7	103.6
3C	1.7	836.5	141.2

The three fields to be initially developed are Alur Rambong, Alur Siwah and Julu Rayeu with the Matang discovery to be appraised and tied into the production facilities at a later date. Sweet gas from Alur Rambong is expected to go into production in 2017, followed by sour gas from Alur Siwah. The Matang field is expected to be brought on stream when production from the Alur Siwah field declines from plateau.

The development plan includes the construction of a 70 mmcfd gas plant for carbon dioxide and hydrogen sulphide removal. Up to 18 wells, involving a combination of new wells and re-entry and completion of existing wells, will be drilled during the development.

In January 2015, the operator, PT. Medco E&P Malaka, announced it had signed a gas sales agreement for a daily contracted quantity of 58 billion British thermal units with an agreed gas price of US$9.45/mmBtu.



EAST SERUWAY PSC
EXPLORATION

PARTNERS

KrisEnergy (operator)	100%

LOCATION
North Sumatra Basin, Malacca Strait

WATER DEPTHS
25 – 60 metres

The North Sumatra Basin comprises a series of northerly trending rifted horst and grabens comprising an initial Oligo-Miocene lacustrine-non-marine sedimentary infill, overlain by Early Miocene-aged reefal carbonates and Middle-Late Miocene deepwater marine shales and claystones.

Exploration activity began in the general area of the East Seruway PSC in the 1960s with a number of 2D seismic surveys acquired through to 1998. Six exploration wells drilled between 1974 and 1984 resulted in one gas and condensate discovery and one gas discovery. In 2013, a 948 km 2D seismic acquisition program was completed from which 15 prospects and leads have been identified and mapped.

In line with the Indonesian licensing regulations governing the exploration period, the authorities approved the final relinquishment of the original gross acreage of the contract area in October 2014 leaving a remaining area of 1,172 sq. km. The authorities also approved a 19-month extension to the East Seruway PSC, which runs until 12 June 2016.

West Papua

The Udan Emas PSC is located onshore West Papua over the Bintuni Basin, a proven prolific gas province containing several multiple-trillion-cubic-feet gas discoveries. Preliminary geological and geophysical evaluation has identified a Mesozioic play fairway and two leads, supported by old seismic and gravity data, favourably located on the southeast margin of the Bintuni Basin.



UDAN EMAS PSC
EXPLORATION

PARTNERS

KrisEnergy (operator)	100%

LOCATION
Onshore West Papua over Bintuni Basin

Since 2012, KrisEnergy has been planning and preparing a 300 km transition zone 2D seismic acquisition program, the first shot of which was recorded on 26 January 2015. More than 1,300 workers are involved in the program in this remote and rugged location. Great care has been taken to socialise the preparation and recording activities with the 32 villages within the seismic zone. For a brief description of the exploration program, see *Spotlight on Indonesia: Rumble in the Jungle* on pages 24–25.

Seismic acquisition is anticipated to be completed in June 2015 with data processing continuing until the end of 2015. Concurrently, an airborne gravity and magnetic survey will be recorded over the contract area. This survey will be integrated with surface geology and the new seismic data to identify prospects for drilling.



COUNTRY FACTS

Capital city	Hanoi
Largest city	Ho Chi Minh City
Official language	Vietnamese
Ethnic groups	Kinh Tay Tai Murong Khmer Krom Hoa Nùng Hmong
Total area	**310,070 sq. km**
Population	
2013	89,708,900
GDP (PPP)	**2013 estimate**
Total	US$475.0 billion
Per capita	US$5,294
Currency	**Dong (VND)**

KRISENERGY

Office	19F, Bitexco Financial Tower, No. 2, Hai Trieu Street, Dist. 1, Ho Chi Minh City

VIETNAM

Vietnam lies on the eastern margin of the Indochinese peninsula and borders the Gulf of Thailand, Gulf of Tonkin and South China Sea. The country's continental shelf covers approximately 1 million sq. km and comprises seven major Tertiary Basins and groups of basins, of which the southern offshore Nam Con Son and Cuu Long Basins have been the most prolific hydrocarbon producing regions to date.

KrisEnergy holds working interests in three exploration licences, Block 105 and Block 115/09 in shallow waters of the Song Hong Basin offshore north-central Vietnam and Block 120 in moderate water depths in the northern Phu Khanh Basin, offshore central Vietnam. These exploration blocks are underexplored and all contain a variety of plays and prospects.

In 2014, Neon Energy withdrew its participation in Block 105 and Block 120 and its 25% working interest was transferred on a *pro rata* basis to operator Eni and KrisEnergy. KrisEnergy's working interest in both blocks has increased to 33.33% and Eni's working interest to 66.67%.



BLOCK 105
EXPLORATION

PARTNERS

KrisEnergy	33.33%
Eni (operator)	66.67%

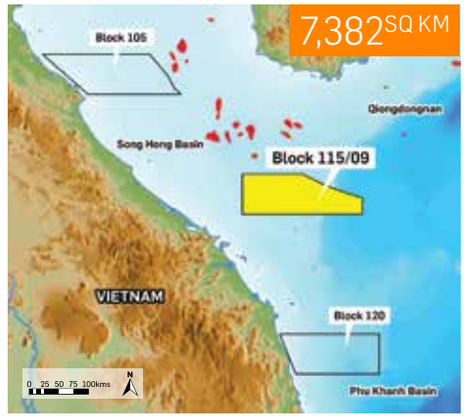
LOCATION
Central Song Hong Basin

WATER DEPTHS
20 – 80 metres

Block 105 is located at the outlet of the extensive paleo-Song Ca river system in a favourable position for the deposition of quartz-rich sand reservoirs in slope fans and basin floor fan/channel complexes. These reservoirs are developed in a series of structural/stratigraphic traps associated with faults and shale diapirs, which are analogous to the producing Dong Fang gas fields located immediately to the east of the concession in Chinese waters. A secondary play comprises stacked Early to Late Miocene-aged fluvio-deltaic sandstone reservoirs trapped in large up-thrown fault blocks along the faulted western margin of the Song Hong Basin.

The Cua Lo-1/1ST exploration well, the first well to be drilled in the block, commenced drilling in October 2013 and completed in January 2014. Based on log interpretation, several Pliocene-aged gas bearing slope fan sandstone reservoirs were identified. A drill stem test was conducted on a reservoir evaluated with the largest potential within the prospect and although gas flowed during the test, poor reservoir deliverability rate combined with high carbon dioxide content suggested that the future development of the tested reservoir was unlikely.

Data from the Cua Lo-1/1ST drilling results have been integrated into the geological model and a thorough review and remapping of the multiple prospects and leads within the block is underway.



BLOCK 115/09
EXPLORATION

PARTNERS

KrisEnergy (operator)	100%

LOCATION
Song Hong Basin

WATER DEPTHS
60 – 200 metres

KrisEnergy was awarded 100% working interest in and operatorship of Block 115/09 in March 2014. The PSC has an initial four-year term, with an associated work commitment of the reprocessing of 3,000 km of existing 2D seismic data, the acquisition and processing of 850 sq. km of 3D seismic data and a single exploration well.

Block 115/09 is an under-explored exploration block, with approximately 3,600 km of 2D seismic data acquired in 1990. A single well, 115-A-1X, was drilled in 1991 and encountered a 310 metre gas column with high carbon dioxide.

Preliminary mapping of the existing 2D seismic data identified a Tertiary carbonate build-up in addition to progradational Tertiary through present day clastic sequences with associated deltaic/shelfal, slope and deepwater fan systems. Various petroleum plays within this stratigraphic section have been identified, including a Miocene-aged reefal carbonate build-up and Oligo-Miocene clastics within marginal basin tilted fault blocks, in addition to Mio-Pliocene clastics associated with diapiric structuring and drape compaction.

Reprocessing of the 2D seismic data was completed in 2014, and will be reviewed to identify prospective areas of the block for a 3D seismic acquisition program, which is planned during 2016.



BLOCK 120
EXPLORATION

PARTNERS

KrisEnergy	33.33%
Eni (operator)	66.67%

LOCATION
Overlying Quang Ngai Graben in north and central areas, passing into Phu Khanh Basin in the south

WATER DEPTHS
50 – 650 metres

Block 120 lies offshore central eastern Vietnam over the Quang Ngai Graben and the Tri Ton Horst. The graben connects the Song Hong and Qiongdongnan Basins in the north, with the Phu Khanh Basin in the south. Rifting began in the late Eocene as the South China Sea commenced breakup and the Indochina block extruded to the southeast. Lacustrine, fluvial and shallow marine synrift sediments were deposited in the resultant elongate rifts throughout the Song Hong, Quang Ngai and Phu Khanh Basins.

In line with Vietnamese licensing regulations, the authorities approved in February 2015 the relinquishment of 20% of the original contract area as required at the end of the first exploration period. The acreage of Block 120 reduced to 6,869 sq. km from 8,574 sq. km.

Two exploration wells, 120-CS-1X and Ca Ngu-1, have been drilled in the block following extensive mapping of multiple prospects from seismic data. Both wells encountered oil and/or gas shows, confirming the existence of a petroleum system in the area.

The Ca Ngu-1 well commenced drilling in October 2013 and was completed in January 2014. Wireline log data confirmed the presence of low saturation gas in Pliocene sandstone reservoirs, with a 15.2 metre gross oil and gas column within the main Miocene-aged carbonate reservoir target. The 120-CS-1X well, drilled in 1993, encountered hydrocarbons with an interpreted 6 metre oil column at the top of the main Miocene carbonate reservoir target, overlying a 26 metre section of oil and gas shows.

Data from the Ca Ngu-1 well has been integrated into the existing seismic data and a review of the geological model was completed during 2014. A 550 sq. km 3D seismic acquisition program, to further high grade the next drilling target, is planned for 2015.

FISCAL TERMS

The petroleum licences in which we have interests contain the terms of our concessions as agreed between the participants and the relevant host government. The economic terms of these licences, commonly known as fiscal terms, vary depending on jurisdiction.





BANGLADESH

The table below sets out the material fiscal terms of our Bangladesh assets.

	BLOCK 9	SS-11
DMO FOR OIL	With six months' prior written notice, Petrobangla may require contractor to provide its *pro rata* share of oil, up to 25.0% of its share of profit oil, for domestic consumption.	With six months' prior written notice, Petrobangla may require contractor to provide its *pro rata* share of oil, up to 80.0% of its share of profit oil, for domestic consumption.
DMO PRICE FOR OIL	15.0% discount to fair market value.	15.0% discount to fair market value.
DMO FOR GAS	Contractor must first offer all its share of gas to Petrobangla and its affiliates. If Petrobangla or its affiliates does not purchase the gas within six months of contractor's submission of an evaluation report, contractor is free to find a market outlet within Bangladesh.	Contractor must first offer all its share of gas to Petrobangla and its affiliates. If Petrobangla or its affiliates does not purchase the gas within six months of contractor's submission of an evaluation report, contractor is free to find a market outlet within Bangladesh.
DMO PRICE FOR GAS	Price of gas sold to Petrobangla and its affiliates is set at 75.0% of the average for each calendar quarter of Platt's Oilgram quotations of High Sulphur Fuel Oil 180 CST, free-on-board ("FOB") Singapore with a floor price of US$70 per metric tonne and ceiling price of US$120 per metric tonne. Price of gas sold to Petrobangla is subject to a further 1.0% discount. Price of gas sold to third parties shall be equal to or greater than the pricing formula described above.	Price of gas sold to Petrobangla and its affiliates is set at 75.0% of the average for each calendar quarter of Asian Petroleum Price Index quotations of High Sulphur Fuel Oil 180 CST, FOB Singapore with a floor price of US$100 per metric tonne and ceiling price of US$200 per metric tonne. Price of gas sold to Petrobangla is subject to a further 1.0% discount. Price of gas sold to third parties shall be equal to or greater than the pricing formula described above.
COST RECOVERY LIMIT		
Oil	Up to 40.0% per calendar year of all oil produced and saved from the contract area and not used in petroleum operations.	Up to 55.0% per calendar year of all oil produced and saved from the contract area and not used in petroleum operations.
Gas	Up to 45.0% per calendar year of all gas produced and saved from the contract area and not used in petroleum operations.	Up to 55.0% per calendar year of all gas produced and saved from the contract area and not used in petroleum operations.

	DURING COST RECOVERY	AFTER COST RECOVERY	
PROFIT OIL SPLIT (TO CONTRACTOR)			
Up to 10,000 bopd	33.0%	30.0%	–
Portion over 10,000 and up to 25,000 bopd	30.0%	25.0%	–
Portion over 25,000 and up to 50,000 bopd	25.0%	20.0%	–
Portion over 50,000 and up to 100,000 bopd	20.0%	15.0%	–
Portion over 100,000 bopd	17.0%	10.0%	–
PROFIT GAS SPLIT (TO CONTRACTOR)			
Up to 75 mmcfd	39.0%	34.0%	45.0%
Portion over 75 and up to 150 mmcfd	39.0%	34.0%	40.0%
Portion over 150 and up to 250 mmcfd	34.0%	27.5%	35.0%
Portion over 250 and up to 300 mmcfd	34.0%	27.5%	30.0%
Portion over 300 and up to 400 mmcfd	27.5%	22.0%	30.0%
Portion over 400 and up to 450 mmcfd	27.5%	22.0%	25.0%
Portion over 450 and up to 600 mmcfd	25.0%	17.5%	25.0%
Portion over 600 mmcfd	18.0%	15.0%	20.0%
PROFIT CONDENSATE/LIQUIDS (TO CONTRACTOR)			
Up to 3,000 boepd	35.0%	30.0%	–
Portion over 3,000 and up to 6,000 boepd	32.0%	27.0%	–
Portion over 6,000 and up to 10,000 boepd	28.0%	25.0%	–
Portion over 10,000 and up to 15,000 boepd	25.0%	20.0%	–
Portion over 15,000 boepd	20.0%	15.0%	–

	BLOCK 9		SS-11
	DURING COST RECOVERY	AFTER COST RECOVERY	
PROFIT OIL AND CONDENSATE/LIQUIDS (TO CONTRACTOR)			
Up to 5,000 boepd	–	–	45.0%
Portion over 5,000 and up to 12,500 boepd	–	–	42.5%
Portion over 12,500 and up to 25,000 boepd	–	–	40.0%
Portion over 25,000 and up to 40,000 boepd	–	–	35.0%
Portion over 40,000 and up to 65,000 boepd	–	–	30.0%
Portion over 65,000 and up to 100,000 boepd	–	–	25.0%
Portion over 100,000 boepd	–	–	20.0%
		GENERAL	GENERAL
PRODUCTION BONUS PAYMENTS			
Within 30 days of first commercial discovery		US$1 million	US$3 million
		OIL	OIL
Upon daily average of 10,000 bopd for 30 consecutive days		US$1 million	US$0.5 million
Upon daily average of 20,000 bopd for 30 consecutive days		US$1 million	US$1 million
Upon daily average of 30,000 bopd for 30 consecutive days		US$1 million	US$2 million
Upon daily average of 40,000 bopd for 30 consecutive days		US$2 million	US$2.5 million
Upon daily average of 50,000 bopd for 30 consecutive days		US$2 million	US$3 million
Upon daily average of 100,000 bopd for 30 consecutive days		US$2 million	US$4 million
		GAS	GAS
Upon daily average of 75 mmcfd for 30 consecutive days		US$1 million	US$0.5 milion
Upon daily average of 150 mmcfd for 30 consecutive days		US$1 million	US$1 million
Upon daily average of 225 mmcfd for 30 consecutive days		US$1 million	US$2 million
Upon daily average of 300 mmcfd for 30 consecutive days		US$2 million	US$2.5 million
Upon daily average of 375 mmcfd for 30 consecutive days		US$2 million	US$3 million
Upon daily average of 450 mmcfd for 30 consecutive days		–	US$4 million
Upon daily average of 600 mmcfd for 30 consecutive days		US$5 million	US$6 million
INCOME TAX	All Bangladesh income tax levied on petroleum operations are borne and discharged by Petrobangla		All Bangladesh income tax levied on petroleum operations are borne and discharged by the contractor
BANGLADESH PARTICIPATION OPTION	None		None

CAMBODIA

The table below sets out the material fiscal terms of Cambodia Block A.

	BLOCK A	
ROYALTY	12.5% of production	
COST RECOVERY PETROLEUM	90.0% of production	
ALLOCATION OF REMAINING OIL (TO CONTRACTOR) (average annual production)	Up to 10,000 and up to 25,000 bopd	58.0%
	In excess of 10,000 – 25,000 bopd	53.0%
	Portion over 25,000 and up to 50,000	48.0%
	Portion over 50,000 bopd	38.0%
ALLOCATION OF REMAINING GAS (TO CONTRACTOR)	65.0%	
INCOME TAX (NOT PAYABLE ON THE ROYALTY PETROLEUM OR COST RECOVERY PETROLEUM)	25.0% for five years from first profit and 30.0% thereafter.	
PRODUCTION BONUS PAYMENT	None	
ANNUAL SURFACE RENTAL FEE	US$500 per sq. km of unrelinquished production area and up to US$40 per sq. km of unrelinquished exploration area.	
MME OPTION	5.0% exercised on 15 November 2011 and currently under negotiation.	

NOTES:
(1) Negotiations with the Cambodian authorities on the terms of the production permit and Petroleum Agreement for Cambodia Block A are ongoing. The fiscal terms for Cambodia Block A may be amended as a result of the resolution reached with the Cambodia authorities

INDONESIA

The table below sets out the material fiscal terms of our Indonesian assets.

	BLOCK A ACEH	BULU	EAST MURIAH	EAST SERUWAY	KUTAI	SAKTI	TANJUNG ARU	UDAN EMAS
FTP (Oil and gas) (as % of total petroleum production)	20.0%	10.0%	20.0%	20.0%	10.0%	20.0%	20.0%	20.0%
Effective Tax Rate	40.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%
DMO for oil	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
DMO for gas	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
DMO price for oil (% of market price)	15.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
DMO price for gas (% of market price)	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Pre-tax profit oil split to contractor	25.0%	37.5%	26.8%	26.8%	35.8%	41.7%	58.3%	58.3%
Pre-tax profit gas split to contractor	58.3%	62.5%	53.6%	53.6%	53.6%	58.3%	66.7%	66.7%
PRODUCTION BONUS PAYMENTS UPON CUMULATIVE PRODUCTION HAVING REACHED:								
25 mmboe	US$1 million	–	US$1 million	US$1 million	US$1 million	US$1 million	US$1 million	US$1 million
50 mmboe	US$2 million	US$500,000	US$2 million	US$1 million	US$2 million	US$1.5 million	US$1.5 million	US$1.5 million
75 mmboe	–	US$1 million	US$3 million	US$1 million	US$3 million	US$2 million	US$2 million	US$2 million
100 mmboe	US$4 million	–	–	–	–	–	–	–
125 mmboe	–	US$2 million	–	–	–	–	–	–
INDONESIAN PARTICIPATION OPTION	–	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
ACEH PARTICIPATION OPTION	10.0%	–	–	–	–	–	–	–
LOCAL COMMUNITY FUND CONTRIBUTION	1.0% of gross revenue	–	–	–	–	–	–	–

THAILAND

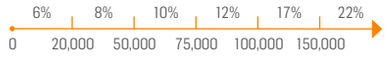
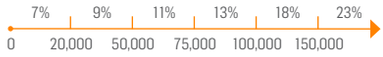
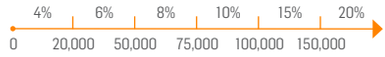
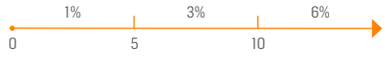
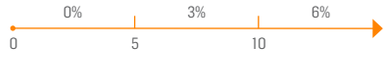
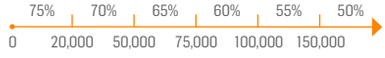
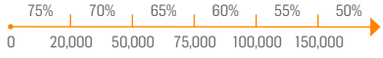
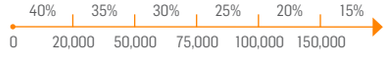
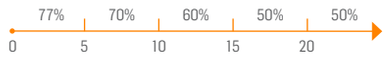
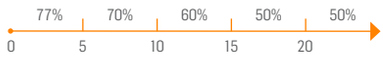
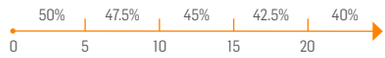
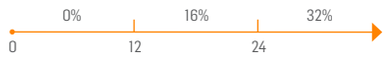
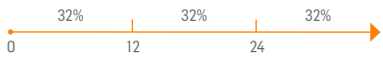
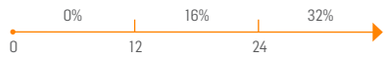
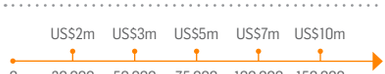
The table below sets out the material fiscal terms of our Thai assets.

	B9A	B8/32, G6/48, G10/48 & G11/48	
ROYALTY (as % of the value of petroleum sold or disposed in each month)	12.5%	0 – 60,000 barrels	5.00%
		60,000 – 150,000 barrels	6.25%
		150,001 – 300,000 barrels	10.00%
		300,001 – 600,000 barrels	12.50%
		Over 600,000 barrels	15.00%
INCOME TAX RATE	50.0%		50.0%
ANNUAL SURFACE RESERVATION FEE	THB 4,000 per sq. km per year		None
SPECIAL REMUNERATORY BENEFIT	None	Payable at the end of each fiscal year in various rates based on the profit earned during the year up to a maximum payment of 75.0% of the profit earned.	

		B8/32	G6/48	G10/48	G11/48
PRODUCTION BONUS PAYMENT	Fully discharged	Fully discharged	US$0.3 million payable within 30 days from day total production from the contract area first averages 10,000 boepd for 90 consecutive days	US$0.5 million payable within 30 days from day total production from the contract area first averages 20,000 boepd for 30 consecutive days	US$0.5 million payable within 30 days from day total production from the contract area first averages 20,000 boepd for 30 consecutive days
THAI PARTICIPANT OPTION	None	None	None	10.0%	10.0%

VIETNAM

The table below sets out the material fiscal terms of our Vietnam assets.

	BLOCK 105	BLOCK 115/09	BLOCK 120
ROYALTY ON OIL (BOPD)			
ROYALTY ON GAS (MMCFD)			
COST RECOVERY LIMIT	70% of gross reserves	70% of gross reserves	70% of gross reserves
PRE-TAX PROFIT OIL SPLIT (TO CONTRACTOR)			
PRE-TAX PROFIT GAS SPLIT (TO CONTRACTOR)			
INCOME TAX RATE			
OIL EXPORT DUTY	10.0%	10.0%	4.0%
PRODUCTION BONUS PAYMENTS			
GENERAL			
Within 30 days of first commercial discovery	US$1 million	US$1 million	US$2 million
Within 30 days of first commercial production	US$1 million	US$1 million	US$2 million
OIL (BOPD) 30 consecutive days			
GAS (MMCFD) 30 consecutive days			
PetroVietnam option	20.0%	20.0%	20.0%

The table below sets out certain information regarding our oil and gas assets as at 28 February 2015.

COUNTRY/ ASSET NAME	EFFECTIVE INTEREST (%)	STATUS[1]	EFFECTIVE DATE	LICENCE EXPIRY DATE	EXPLORATION PERIOD	PRODUCTION AREA	PRODUCTION PERMIT EXPIRY DATE	LICENCE AREA (SQ. KM)	TYPE OF MINERAL OIL OR GAS DEPOSIT	LICENCE TYPE
BANGLADESH										
BLOCK 9[2]	30.0	Production & development unclarified	11 April 2001	26 August 2033	–	Bangora	26 August 2033[3]	1,770	Gas / Condensate	PSC
SS-11	45.0	Exploration	12 March 2014	See Note 3	11 March 2019 [3]	–	–	4,475	Oil/Gas	PSC
CAMBODIA										
BLOCK A[4]	55.0[5]	Development pending & development unclarified	18 March 2002	See Note 6	See Note 6	–	–	4,709	Oil	Petroleum Agreement
INDONESIA										
BLOCK A ACEH	41.6666	Development pending & development unclarified	1 September 2011	31 August 2031	31 August 2031	–	–	1,867	Gas/ Condensate	PSC
BULU	42.5	Near production	14 October 2003	13 October 2033	–	Lengo	13 October 2033	697	Gas	PSC
EAST MURIAH	50.0	Development pending	13 November 2008	12 November 2038	13 November 2008 to 12 November 2018[6]	–	–	3,751	Gas	PSC
EAST SERUWAY	100.0	Exploration	13 November 2008	12 November 2038	13 November 2008 to 12 June 2016[6]	–	–	1,172	Oil/Gas	PSC
KUTAI	54.6	Development pending	16 January 2007	15 January 2037	16 January 2007 to 15 January 2017[6]	–	–	944	Gas	PSC
SAKTI	95.0	Exploration	26 February 2014	25 February 2044	26 February 2014 to 25 February 2020[6]	–	–	4,974	Oil/Gas	PSC
TANJUNG ARU	43.0[7]	Development unclarified	19 December 2011	18 December 2041	19 December 2011 to 18 December 2017[6]	–	–	3,143	Gas	PSC
UDAN EMAS	100.0	Exploration	20 July 2012	19 July 2042	20 July 2012 to 19 July 2018[6]	–	–	5,396	Gas	PSC
THAILAND										
B8/32	4.6345	Production	1 August 1991	31 July 2020 [8]	–	Tantawan	31 July 2020[9]	1,992	Oil/Gas	Tax/ Royalty
						Benchamas South and Pakarong	31 July 2020[9]			
						Maliwan	31 July 2020[9]			
						North Jarmjuree	31 July 2020[9]			
						North Benchamas	31 July 2020[9]			
						Chaba	31 July 2020[9]			

COUNTRY/ ASSET NAME	EFFECTIVE INTEREST (%)	STATUS[1]	EFFECTIVE DATE	LICENCE EXPIRY DATE	EXPLORATION PERIOD	PRODUCTION AREA	PRODUCTION PERMIT EXPIRY DATE	LICENCE AREA (SQ KM)	TYPE OF MINERAL OIL OR GAS DEPOSIT	LICENCE TYPE
B9A	4.6345	Production	17 July 2003	16 July 2041	–	Rajpruek	16 July 2041	80	Oil/Gas	Tax/ Royalty
G6/48	30.0	Development pending	8 January 2007	See Note 9	8 January 2007 to 7 January 2016[6]	–	–	566	Oil	Tax/ Royalty
G10/48[10]	100.0 [11]	Near production, development pending & development unclarified	8 December 2006	See Note 9	8 December 2006 to 7 December 2015[6]	Wassana	7 December 2035[9]	4,696	Oil	Tax/ Royalty
G11/48	22.5	Near production & development unclarified	13 February 2007	See Note 9	13 February 2007 to 12 February 2016[6]	Nong Yao	12 February 2036[9]	3,374	Oil	Tax/ Royalty
VIETNAM										
BLOCK 105	33.33	Exploration	3 February 2010	2 February 2040	3 February 2010 to 2 February 2016	–	–	7,192	Oil/Gas	PSC
BLOCK 115/09	100.0	Exploration	31 March 2014	30 March 2044	31 March 2014 to 30 March 2018	–	–	7,382	Oil/Gas	PSC
BLOCK 120	33.33	Exploration	23 January 2009	22 January 2039	23 January 2009 to 22 January 2017	–	–	6,869	Oil/Gas	PSC

NOTES:

(1) Each of our contract areas also holds exploration prospects and leads

(2) Resources associated with the Lalmai gas discovery are classified as development unclarified

(3) The production permit for gas will be valid for 25 years with an extension period of up to five years

(4) Resources associated with Platform A within Cambodia Block A are classified as development pending and resources associated with Platform B and Platform C within Cambodia Block A are classified as development unclarified

(5) Assuming completion of the formal transfer of 5.0% interest in Cambodia Block A to the relevant government corporation as decided by the Cambodian Ministry of Mines and Energy, we will indirectly hold a 52.25% working interest in Cambodia Block A

(6) Exploration period may be extended with the approval of the host government

(7) Assuming receipt of governmental approval to transfer Neon Energy interest in the Tanjung Aru PSC to us due to Neon Energy default and withdrawal from the Tanjung Aru PSC, we will hold an 85.0% working interest in the Tanjung Aru PSC

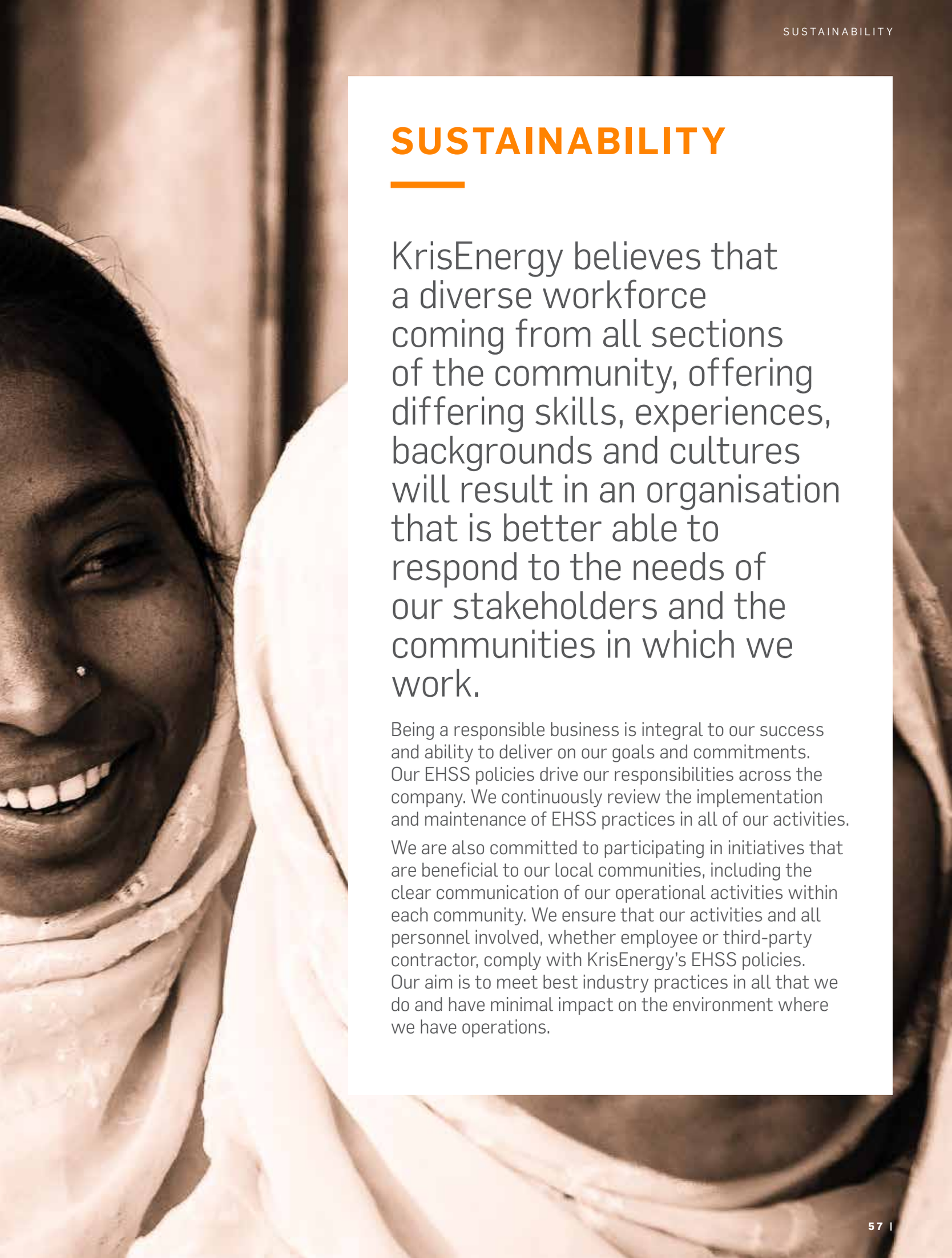
(8) Licence expiry dates can be extended accordingly if host government grants extension of exploration period or production permit

(9) Production permits are valid for 20 years with an extension period of up to 10 years

(10) Resources associated with the Wassana and Niramai discoveries within G10/48 are classified as development pending and resources associated with the Mayura discovery within G10/48 are classified as development unclarified

(11) On 5 February 2015, we completed the sale of 14.67% shareholding interest in KrisEnergy Management Ltd to Palang Sophon. KrisEnergy Management Ltd holds 100.0% of KrisEnergy G10 (Thailand) Ltd, which holds a 75.0% working interest in G10/48. Our wholly-owned entity, KrisEnergy (Gulf of Thailand) Ltd holds the remaining 25.0% working interest in, and operatorship of G10/48





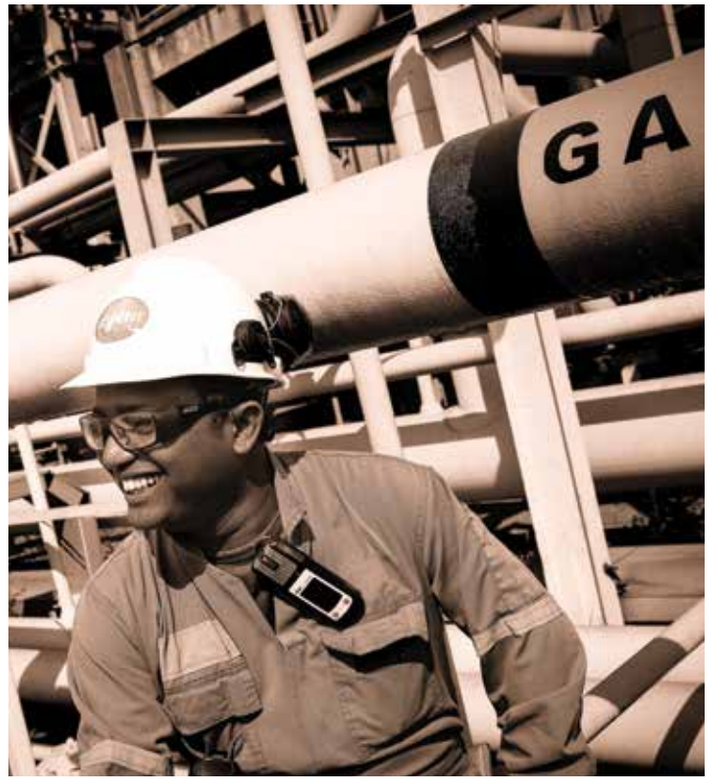
SUSTAINABILITY

KrisEnergy believes that a diverse workforce coming from all sections of the community, offering differing skills, experiences, backgrounds and cultures will result in an organisation that is better able to respond to the needs of our stakeholders and the communities in which we work.

Being a responsible business is integral to our success and ability to deliver on our goals and commitments. Our EHSS policies drive our responsibilities across the company. We continuously review the implementation and maintenance of EHSS practices in all of our activities.

We are also committed to participating in initiatives that are beneficial to our local communities, including the clear communication of our operational activities within each community. We ensure that our activities and all personnel involved, whether employee or third-party contractor, comply with KrisEnergy's EHSS policies. Our aim is to meet best industry practices in all that we do and have minimal impact on the environment where we have operations.

EHSS
ENVIRONMENT, HEALTH, SAFETY & SECURITY



Our Health and Safety Policy emphasises our responsibilities for the health, safety and security of every individual involved in our operations. We undertake risk management and ensure we comply with, or exceed, the relevant legal requirements for our operations. We develop and nurture safety awareness and a safety culture among all employees and as a result of this, create individual responsibility for health and safety at all levels. All EHSS policies and procedures are compliant with OHSAS 18001 and ISO 14001 requirements.

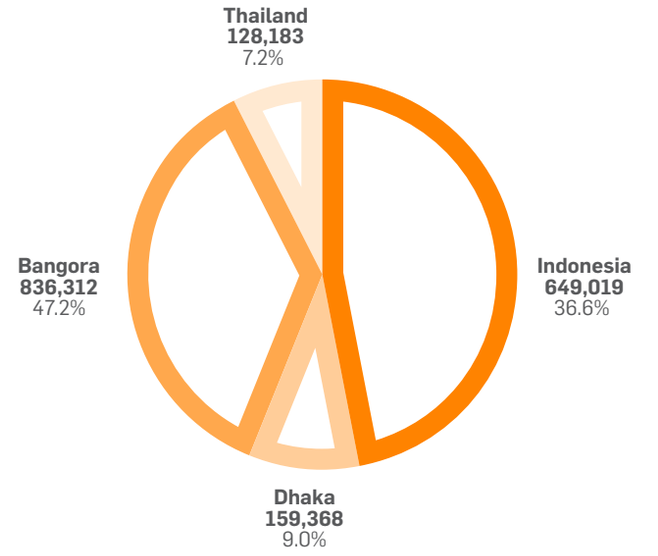
We are aware that successful health and safety management is based upon five key principles: a suitable and sufficient policy; organisation; planning; implementation; and performance review. It is the company's policy to adopt these principles.

We engage in an effective Environmental, Health and Safety Management System ("EHSMS") as it is our legal obligation to comply with legislation, our moral obligation to our people and lastly to protect our business reputation. The EHSMS provides a platform to manage our risks, reduce potential accidents and improve operational performance. Our regional incident and accident reporting system is established on a single group-wide platform in a structured Business Management System.

We recognise that our activities affect the environment and the communities in which we operate. Our Environmental Policy highlights our commitment to comply with all applicable environmental legislation requirements and to minimise and prevent pollution at the source wherever and whenever possible.

Our Singapore office attained full OHSAS 18001 and ISO 14001 certifications in 2012 and in 2013, respectively, as awarded by SGS International Certification Services accredited by both the Swiss Accreditation Service and the United Kingdom Accreditation Services. In December 2014, our Jakarta office received OHSAS 18001 certification, and our Dhaka office and the Bangora field operations, onshore Bangladesh, were awarded ISO 14001 certification.

The process is underway for all KrisEnergy regional offices to eventually attain full OHSAS 18001 and ISO 14001 certifications. These standards and accreditations will be transferred into all new operations.



Between January and December 2014, the KrisEnergy group achieved 1,772,882 man-hours at operated assets without a Lost Time Injury.

CSR
CORPORATE SOCIAL RESPONSIBILITY

Our CSR vision focuses on the alleviation of poverty and the sustainable well-being of the communities in host countries through social investment, volunteerism, research and the robust exchange of ideas. We ensure our activities are measurable and long lasting for the communities. Our priority lies in education, which provides individuals the knowledge and skills to improve their lives and participate in the wider society. Education reduces poverty, boosts economic growth, promotes gender equality and generally results in improved healthcare.

We support healthcare and community development programs that lead to better standards of living and promote self-sufficiency. In 2014, we supported several educational programs throughout Southeast Asia and contributed to the welfare and development of children and teenagers. Our contributions included educational sponsorships, mentoring and supporting students in social entrepreneurship initiatives, financial and equipment donations to orphanages and donations for disaster relief. Find out more about our CSR activities in Bangladesh on pages 60–63, *Spotlight on Bangladesh: Wood, Water, Wisdom*.

As we increase our CSR activities in the region, our endeavours will include community development in our operational areas where we intend to support education, training, health, and village and social development. Where appropriate, our programs will be planned in consultation with governments and the local communities and authorities to provide practical solutions and sustainable results.

DIVERSITY & EQUALITY

We promote equality of opportunity and the elimination of all forms of discrimination. Our goal is to maintain a healthy and positive working and learning environment, which creates mutual respect and dignity and enables everyone to realise their full potential.

We respect human rights and will not tolerate any level of bullying, discrimination, harassment or victimisation by or towards any of our employees, contractors, suppliers, stakeholders and visitors. Any such cases are taken seriously and may result in disciplinary or other appropriate action including termination of contract.

We firmly uphold fair employment practices and in formulating employment policies KrisEnergy is guided by the relevant legislation when establishing employee contracts. These policies are regularly reviewed and new policies are introduced following consultation with employees.

> "KrisEnergy seeks to make lasting improvements to the least advantaged people in the communities within which we work."
>
> *— Hinna Ijaz*
>
> *Corporate EHSS & CSR Manager*



SPOTLIGHT ON BANGLADESH

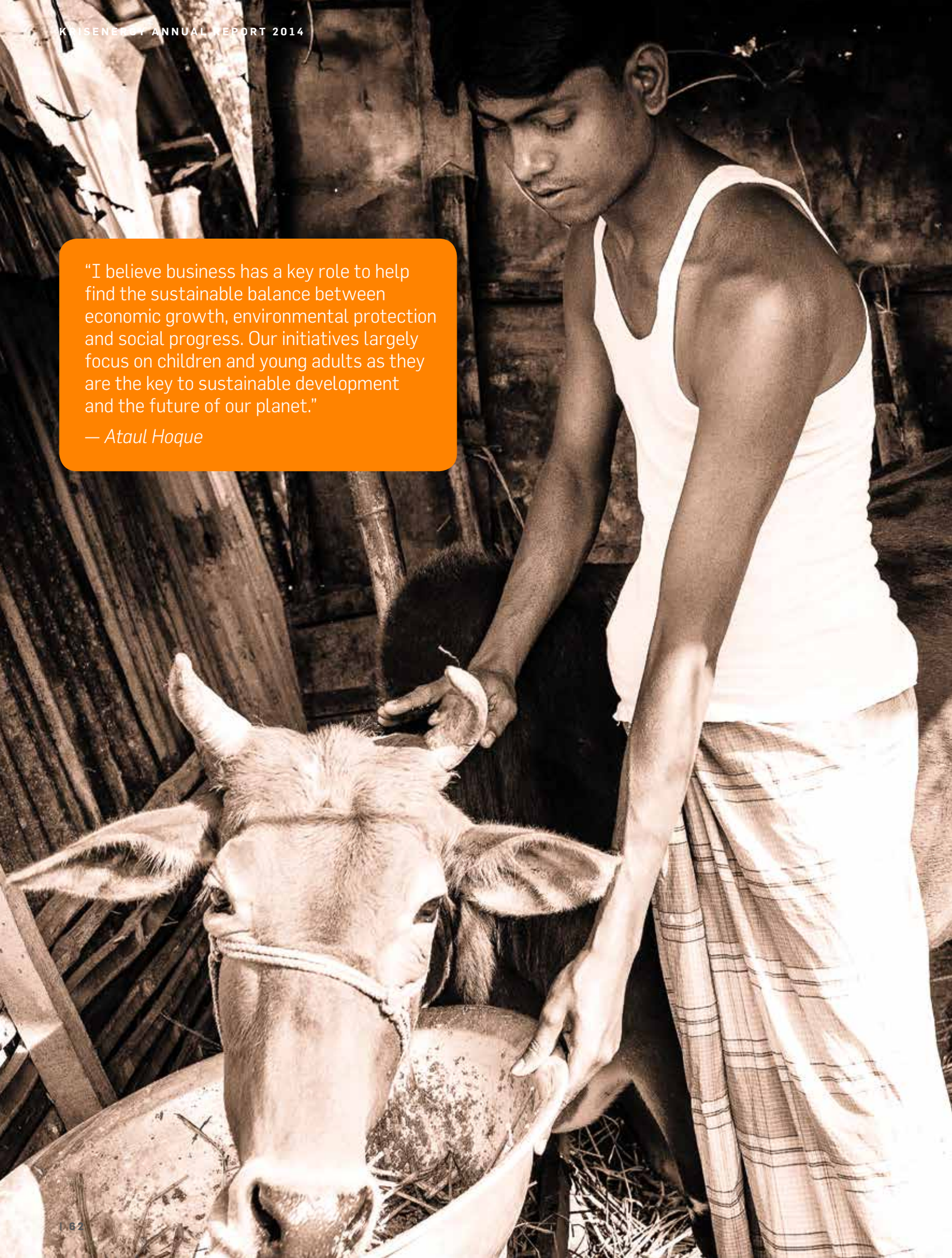




WOOD, WATER, WISDOM

KrisEnergy completed the acquisition of Tullow Bangladesh Ltd in December 2013. The acquisition brought a full complement of staff in Dhaka as well as the operatorship of Block 9 and the associated Bangora gas field operation at Muradnagar Upazilla in Comilla District, approximately 128 km by road from the capital.

In 2014, we continued to build on the community programs established by the previous operator. KrisEnergy supports primary and high schools near the field operations, providing educational materials, scholarships, IT and science lessons for students and science training for teachers as well as various healthcare initiatives and adult empowerment programs.



"I believe business has a key role to help find the sustainable balance between economic growth, environmental protection and social progress. Our initiatives largely focus on children and young adults as they are the key to sustainable development and the future of our planet."

— Ataul Hoque

Ataul Hoque, who oversees KrisEnergy's External Affairs & CSR activities in Bangladesh, highlights three of our programs in the district surrounding the Bangora field location.

SETTING ROOTS

Trees provide kindling for heating and cooking, fruit and spices, timber to build homes, shade to shelter from the sun and roots that anchor the soil.

Trees are life in rural communities across the developing world, but often economic hardship or population pressures lead to wide-scale deforestation. According to the World Bank, 11% of Bangladesh's land area was covered by forest in 2012. As part of the Millennium Goals for Development, the country set itself a target of 20% by 2015.

The Tree Plantation Program distributes saplings to children in approximately 20 schools in Comilla District. The saplings are one to two years old and range from 4 feet to 6 feet in height. Varieties include mango, lychee and guava, as well as medicinal species and timber-producers like teak, mahogany and acacia. The program aims to educate children and their families about the value of trees and how to care for them as well as providing an additional economic benefit.

KrisEnergy distributed 19,000 saplings in 2014 and overall the program has given out 80,000 young trees since it was established in 2007.

WATER SAFETY

Although 95%[1] of Bangladesh's population has access to drinking water through boreholes/ tubewells, contamination of the groundwater by naturally occurring arsenic is widespread in the country. Long-term exposure to arsenic may lead to skin problems, circulatory and nervous disorders and various forms of cancer.

The Nirapad Paani, or Safe Water, Program provides public-water filtration systems to remove arsenic and other chemical contaminants such as phosphate, manganese and iron, as well as microbes. The plants, which use granular ferric hydroxide as the filtration medium, are installed at selected schools, where they are secure and accessible to the entire community. A joint committee between the school authority and local community is provided training to ensure regular maintenance and replacement of the filtration system. Each plant can filter up to 300 litres an hour, providing clean water for drinking and cooking for about 50 families, who pay a token sum to draw water and an annual fee for the maintenance of the plants.

KrisEnergy has installed three filtration plants in the area, bringing to six the total number of filtration systems in the Comilla District. We plan to install additional filtration plants in 2015.

EMPOWERMENT

The immediate area around the Bangora field operation is rural with agriculture forming the mainstay of the economy. Industrial infrastructure is underdeveloped, constraining the market for skills and products and limiting opportunities for education or self-improvement.

In 2011, the Bangora Initiative for Livelihood Development, or BILD, was launched to focus on the poorest and most vulnerable members of the communities surrounding the Bangora field operation. The program is implemented on the ground by the non-governmental organisation, Friends in Village Development Bangladesh, and has 11 Community Learning Centres ("CLCs") to provide training and micro-loans to individuals or households as start-up seed capital.

Courses range from rearing goats to fish farming, repairing engines and cell phones to sewing or micro-farming. Members can also train to become traditional birth attendants or take courses in leadership and CLC management.

KrisEnergy provides seed funding to each CLC, which distributes sums among its members in the form of business loans. The loans are reimbursed from future earnings and monthly reporting by the CLC indicates a repayment rate of approximately 95%. Activities are monitored by a project manager against the original business plan and regular site visits ensure proper utilisation of funds. To date, almost 900 people have benefitted from BILD training.



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[1] WHO/UNICEF Joint Monitoring Programme, *Bangladesh: estimates on the use of water sources and sanitation failities (1980–2012)*

GROUP OVERVIEW




KRISENERGY

BOARD OF DIRECTORS

Will Honeybourne
John Koh
Keith Cameron
Chris Gibson-Robinson
Richard Lorentz
Brooks Shughart
Choo Chiau Beng
Loh Chin Hua
Duane Radtke
Jeff MacDonald
Tan Ek Kia
Alan Nisbet
Keith Pringle



WILL HONEYBOURNE (63)

NON-EXECUTIVE CHAIRMAN

Bachelor of Science in Oil Technology, Imperial College, University of London; Member of the Society of Petroleum Engineers; Member of the Society of Exploration Geophysicists

Date of first appointment as Director:
5 October 2009

Length of service as a Director (as at 31 December 2014):
5 years 3 months

KrisEnergy Board Committee(s) served on:
Nominating Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd; Exterran Holdings, Inc.

Other principal directorships:
Barra Holdings GP Ltd; First Reserve Asia Ltd; First Reserve Energy Infrastructure GP Ltd; First Reserve Energy Infrastructure GP II Ltd; First Reserve GP XII Ltd; First Reserve GP XIII Ltd; FR Horizon GP Ltd; FR X Offshore GP Ltd; FR XI Offshore GP Ltd; FR XII Alternative GP Ltd; KrisEnergy Holdings Ltd; FR DGE III Alternative B GP Ltd

Major Appointments (other than directorships):
Managing Director of First Reserve

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Acteon Group Ltd; FR Acteon Holdings Ltd; First Reserve International Ltd; KrisEnergy Pte Ltd; Red Technology Alliance, LLC; Turbo Cayman Ltd; Petroleum Equipment Suppliers Association.

Others:
Former Director of CNOOC Ltd (China National Offshore Oil Corporation)



JOHN KOH (59)

LEAD NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor of Arts and Master of Arts, University of Cambridge; Bachelor of Law, Harvard Law School

Date of first appointment as Director:
11 January 2013

Length of service as a Director (as at 31 December 2014):
2 years

KrisEnergy Board Committee(s) served on:
Audit Committee (Chairman);
Nominating Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd; NSL Ltd

Other principal directorships:
Artfx Fine Art Services Ltd; Artpac Management Ltd; Bernard Quaritch Ltd; BMH Management Pte Ltd; Brandmine Properties Ltd; Genphar, Inc.; Mapletree Industrial Fund Ltd; Mapletree Industrial Trust Management Ltd (as Trustee-Manager of Mapletree Industrial Trust); Mapp Editions Ltd; Mission Impossible Pte Ltd; Singapore Arts School; Singapore National Library; Worldwide Books Corporation

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Afa Management LLC; Arbutus International Ltd; China Lumena New Materials Corp; Easy Capital Ltd; Mandra Forestry Finance Ltd; Mandra Forestry Holdings Ltd; Mission Impossible International Ltd; Straits Capital Investments Ltd

Others:
Former Managing Director and Senior Advisor of the Goldman Sachs Group; Former Deputy Public Prosecutor in the Singapore Attorney-General's Chambers; Former Deputy Director of the Commercial Affairs Department in the Ministry of Finance; Former founding partner of WongPartnership



KEITH CAMERON (67)

EXECUTIVE DIRECTOR AND CHIEF EXECUTIVE OFFICER

Registered Chartered Accountant; Fellow of the Institute of Chartered Accountants of England and Wales; Member of the Canadian Institute of Chartered Accountants; Member of the Institute of Chartered Accountants, Alberta

Date of first appointment as Director:
5 October 2009

Length of service as a Director (as at 31 December 2014):
5 years 3 months

KrisEnergy Board Committee(s) served on:
Nil

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd

Other principal directorships:
B Block Ltd; KrisEnergy (Bangladesh SS-11) Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte Ltd; Puri Aircraft Ltd; SJ Production Barge Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
KrisEnergy Holdings Ltd; KrisEnergy Management Ltd; Mont D'Or Petroleum Ltd

Others:
Former Chief Financial Officer and Vice President Finance for Gulf Indonesia Resources Ltd, formerly known as the Asamera Group of Companies; Former co-founder and Chief Executive Officer of Pearl Energy Ltd; Former Vice President, New Ventures (South East Asia) and member of Aabar's senior executive team after Pearl Energy Ltd was acquired by Aabar Petroleum Investments Company PJSC ("Aabar")



CHRIS GIBSON-ROBINSON (61)

EXECUTIVE DIRECTOR

Bachelor of Science and Associate Royal School of Mines Degree, Imperial College of Science and Technology, University of London; Master of Science in Marine Earth Science (Geology & Geophysics), University College of London; Chartered Geologist; Chartered Scientist; Fellow of the Geological Society of London; Member of the Geologists' Association of the United Kingdon; Member of the Indonesian Petroleum Association; Member of the South East Asia Petroleum Exploration Society; Member of the Petroleum Exploration Society of Great Britain

Date of first appointment as Director:
5 October 2009

Length of service as a Director (as at 31 December 2014):
5 years 3 months

KrisEnergy Board Committee(s) served on:
Nil

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd

Other principal directorships:
B Block Ltd; KrisEnergy (Bangladesh SS-11) Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte Ltd; SJ Production Barge Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
KrisEnergy Holdings Ltd; KrisEnergy Management Ltd

Others:
Former President and co-owner of Far East Exploration Co. Ltd; Former General Manager for Premier Oil (Halmahera) Ltd; Former Chief Technical Officer of Pearl Energy Ltd; Former Vice President, Operations and Vice President, New Ventures (Southeast Asia) and member of Aabar's senior executive team after Pearl Energy Ltd was acquired by Aabar



RICHARD LORENTZ (59)

EXECUTIVE DIRECTOR

Bachelor of Science in Geology, Oklahoma State University; Master of Science in Geology, University of Philippines; Member of Indonesian Petroleum Association; Member of American Association of Petroleum Geologists; Member of Oklahoma Geological Society; Member of South East Asia Petroleum Exploration Society

Date of first appointment as Director:
5 October 2009

Length of service as a Director (as at 31 December 2014):
5 years 3 months

KrisEnergy Board Committee(s) served on:
Nil

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd

Other principal directorships:
B Block Ltd; KrisEnergy (Bangladesh SS-11) Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd.; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte Ltd; Miclyn Express Offshore Ltd; SJ Production Barge Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Franklin Offshore Holding Pte Ltd; Global Tender Barge Pte Ltd; KrisEnergy Holdings Ltd; KrisEnergy Management Ltd

Others:
Former Manager of the New Business Development department for Elf Aquitaine; Former New Ventures & Exploration Manager for Gulf Indonesia and Senior Production Geologist for Asamera (South Sumatra) Ltd; Former Senior Field Geologist for Oriental Petroleum and Minerals Corp; Former Senior Exploration Geologist and Exploration Manager at Funk Exploration Inc; Former Senior Explorationist at Anglo-Suisse (Pakistan) Inc; Former Chief Business Development Officer and co-founder of Pearl Energy Ltd; Former Vice President New Ventures & Corporate Relations and member of Aabar's senior executive team after Pearl Energy Ltd was acquired by Aabar



BROOKS SHUGHART (37)

NON-EXECUTIVE DIRECTOR

Bachelor of Business Administration in Finance, University of Texas at Austin

Date of first appointment as Director:
16 October 2012

Length of service as a Director (as at 31 December 2014):
2 years 2 months

KrisEnergy Board Committee(s) served on:
Audit Committee (Member);
Remuneration Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd; Sabine Oil & Gas Corporation

Other principal directorships:
Amromco Holdings GP Ltd; KIPP. Inc; KrisEnergy Holdings Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil

Others:
Former Director in the Mergers and Acquisitions Group of Credit Suisse



CHOO CHIAU BENG (67)

NON-EXECUTIVE DIRECTOR

Bachelor of Science (First Class Honours), University of Newcastle upon Tyne (awarded Colombo Plan Scholarship to study Naval Architecture); Master of Science in Naval Architecture, University of Newcastle upon Tyne; Attended the Programme for Management Development at Harvard Business School; Member of Wharton Society of Fellows, University of Pennsylvania

Date of first appointment as Director:
9 July 2012

Length of service as a Director (as at 31 December 2014):
2 years 6 months

KrisEnergy Board Committee(s) served on:
Nominating Committee (Member);
Audit Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd; M1 Ltd

Other principal directorships:
Keppel Care Foundation Ltd[1]

Major Appointments (other than directorships):
Chairman of Board of Governors of Raffles Institution; Member of Board of Trustees of Singapore University of Technology and Design; Member of the Board of the National Research Foundation, Prime Minister's Office, Singapore; Board and Council Member, American Bureau of Shipping; Chairman, Centre for Maritime Studies, National University of Singapore (NUS); Provost's Chair Professor (Practice), Faculty of Engineering and NUS Business School, NUS; Rector, Residential College 4 of NUS; Board Member of Energy Studies Institute of NUS and Singapore Non-Resident Ambassador to Brazil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Keppel Corporation Ltd; Keppel Offshore & Marine Ltd; Keppel Energy Pte Ltd; Keppel Land China Ltd; k1 Ventures Ltd

Others:
Conferred the Public Service Star Award (BBM) in August 2004; Conferred the Meritorious Service Medal in 2008; Conferred the NTUC Medal of Commendation (Gold) Award in May 2007

[1] Mr Choo was appointed Chairman / Director on 12 January 2015



LOH CHIN HUA (53)

NON-EXECUTIVE DIRECTOR

Bachelor Degree in Property Administration, Auckland University (Colombo Plan Scholarship); Presidential Key Executive MBA, Pepperdine University; CFA Charterholder; Registered Valuer from the New Zealand Institute of Valuers

Date of first appointment as Director:
9 July 2012

Length of service as a Director (as at 31 December 2014):
2 years 6 months

KrisEnergy Board Committee(s) served on:
Remuneration Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
Keppel Corporation Ltd; Keppel Land Ltd; Keppel Telecommunications & Transportation Ltd, KrisEnergy Ltd

Other principal directorships:
Keppel Offshore & Marine Ltd; Keppel Infrastructure Holdings Pte Ltd; Alpha Investment Partners Ltd

Major Appointments (other than directorships):
Chief Executive Officer of Keppel Corporation Ltd

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
AAJ Investment Pte Ltd; Alpha Investment Partners (BVI) Ltd; AIBJ Hero Pte Ltd; AIBJ Roppongi Pte Ltd; AIPJ Investment Pte Ltd; All Fortune International Ltd; Allenstand Ltd; Anderhill Ltd; ANOF Korea 1 Private Ltd; Antrohorne Ltd; Asia Real Estate Fund Management Ltd; AREFM (BVI); Ash Springs Ltd; Assibere Ltd; Brenspere Ltd; Bugis City Holdings Pte Ltd; Canyonwater Ltd; Caray Gardens Holdings Ltd; Chiba Investment Pte Ltd; Christus Ltd; Comprohorne Ltd; Core Plus Investment Pte Ltd; Daikanyama (CP) Investment Pte Ltd; Dapenso (CP) Investment Pte Ltd; Divine (AMT) Pte Ltd; Equity (CP) Pte Ltd; Ever Gain Logistics Pte Ltd; Fertile Crescent Ltd; Fusiongold Pte Ltd; Garrard Ventures Pte Ltd; Grathfield Ltd; Great Insight Investments Ltd; Greateast Investments Ltd; Highland Flow Pte Ltd; Hubville Co. Ltd; Japan Core Investment Pte Ltd; Kinetic (AMT) Ltd; Kephinance Investment Pte Ltd; Keppel Energy Pte Ltd; Keppel REIT Management Ltd (Manager of Keppel REIT); Kynson (AMT) Pte Ltd; Lavenson Investment Pte Ltd; Macro (AMT) Pte Ltd; Manesar (AMT) Pte Ltd; Matrix (CP) Investment Pte Ltd; Max Platinum Ltd; Myrick Investment Pte Ltd; Nordic (CP) Pte Ltd; Northern Tech Pte Ltd; Noxh Developments (Cecil) Pte Ltd; Numberspring Ltd; Omnibury Ltd; Pessiborge Ltd; Practical Asia Ltd; Preciousbud Ltd; Prestimorne Ltd; Prime Industrial Holdings Pte Ltd; Primiscorne Ltd; Pteris Global Ltd; Regal (1886) Pte Ltd; Rightbridge Ltd; Ristoria (AMT) Pte Ltd; Rochor Investment Ltd; Sacremorne Ltd; Samnorwood Ltd; Sanholpark Ltd; Sheung Wan (AMT) Pte Ltd; Shibuya (AMT) Pte Ltd; Shine City Investment Ltd; Shiodo (CP) Investment Pte Ltd; Solitaire (AMT) Pte Ltd; Sound Investments Ltd; Spellworth Ltd; Sperishorne Ltd; Tannehill Ltd; Trends (AMT) Pte Ltd; Trillington (AMT) Pte Ltd; Tsukiji (CP) Investment Pte Ltd; UL (CP) Investment Pte Ltd; Wallwrick Ltd; Zelkova (AMT) Pte Ltd

Others:
Former Managing Director at Prudential Investment Management Inc.; Former Head of European Real Estate Group in London of Government of Singapore Investment Corporation



DUANE RADTKE (66)

NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor Degree in Mining Engineering, University of Wisconsin

Date of first appointment as Director:
1 September 2010

Length of service as a Director (as at 31 December 2014):
4 years 4 months

KrisEnergy Board Committee(s) served on:
Nominating Committee (Member);
Remuneration Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
Devon Energy Corporation; KrisEnergy Ltd; Sabine Oil & Gas Corporation

Other principal directorships:
Nil

Major Appointments (other than directorships):
President and Chief Executive Officer of Valiant Exploration LLC

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Smith International (merged with Schlumberger in 2010)

Others:
Former President of Devon International Corporation; Former President and Chief Executive Officer of Dominion Exploration and Production



JEFF MACDONALD (59)

NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor of Science (Hons) in Civil Engineering, Glasgow University

Date of first appointment as Director:
5 October 2009

Length of service as a Director (as at 31 December 2014):
5 years 3 months

KrisEnergy Board Committee(s) served on:
Nominating Committee (Member);
Remuneration Committee (Chairman)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd

Other principal directorships:
Hansa Hydrocarbons Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Delta Energy Ltd; Remora Energy; Stone Mountain Resources

Others:
Former Managing Director at Production Testing Services; Former Engineer and Project Manager at Conoco Inc.; Former Managing Director and Chairman at Blackwatch Petroleum Services Ltd; Former Managing Director of Highland Energy Ltd; Former Chief Executive at Caledonia Oil & Gas Ltd; Former Managing Director at First Reserve



TAN EK KIA (66)

NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor of Science Mechanical Engineering (First Class Honours), Nottingham University; Management Development Programme, International Institute for Management Development, Lausanne, Switzerland; Fellow of the Institute of Engineers, Malaysia; Professional Engineer, Board of Engineers, Malaysia; Chartered Engineer of Engineering Council; Member of Institute of Mechanical Engineers

Date of first appointment as Director:
11 January 2013

Length of service as a Director (as at 31 December 2014):
2 years

KrisEnergy Board Committee(s) served on:
Audit Committee (Member);
Nominating Committee (Chairman)

Present Directorships (as at 31 December 2014):
Listed Companies:
Keppel Corporation Ltd; KrisEnergy Ltd; PT Chandra Asri Petrochemical Tbk; SMRT Corporation Ltd; Transocean Ltd

Other principal directorships:
City Gas Pte Ltd (Chairman); Dialog Systems (Asia) Pte Ltd; Keppel Offshore and Marine Ltd; Star Energy Group Holdings Pte Ltd (Chairman); Singapore LNG Corporation Pte Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil

Others:
Former Vice President (Ventures and Developments) of Shell Chemicals, Asia Pacific and Middle East region (based in Singapore); Former Chairman, Shell companies in North East Asia(based in Beijing); Former Managing Director, Shell Malaysia Exploration and Production



ALAN NISBET (64)

NON-EXECUTIVE INDEPENDENT DIRECTOR

Member of the Singapore Institute of Chartered Accountants

Date of first appointment as Director:
13 May 2014

Length of service as a Director (as at 31 December 2014):
7 months

KrisEnergy Board Committee(s) served on:
Audit Committee (Member);
Remuneration Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd; Halcyon Agri Corporation Ltd

Other principal directorships:
Ascendas Pte Ltd; Accounting and Corporate Regulatory Authority; Standard Chartered Bank (Singapore) Ltd

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Deloitte & Touche Management Services Pte Ltd; Deloitte Consulting SEA Pte Ltd

Others:
Former Partner and Audit Leader in Deloitte & Touche LLP, Singapore



KEITH PRINGLE (55)

NON-EXECUTIVE INDEPENDENT DIRECTOR

Bachelor of Science (Hons) in Geology from Edinburgh University; Master of Science in Petroleum Engineering from Strathclyde University; Member of the Society of Petroleum Engineers

Date of first appointment as Director:
13 May 2014

Length of service as a Director (as at 31 December 2014):
7 months

KrisEnergy Board Committee(s) served on:
Audit Committee (Member);
Remuneration Committee (Member)

Present Directorships (as at 31 December 2014):
Listed Companies:
KrisEnergy Ltd

Other principal directorships:
Nil

Major Appointments (other than directorships):
Nil

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Remora Energy; Delta Energy Ltd; KrisEnergy Ltd

Others:
Former Independent Technical Advisor to KrisEnergy Ltd

MANAGEMENT TEAM

Kiran Raj
James Parkin
Brian Helyer
Tim Kelly
Kelvin Tang
John Bujnoch
Mike Whibley
Stephen Clifford
Chris Wilson
Tanya Pang
Edwin G. Bowles
Malin Ros
Kusmutarto Basuki
Phattarin Jirapojaporn
Nguyen Manh Huyen



KIRAN RAJ

CHIEF FINANCIAL OFFICER VICE PRESIDENT FINANCE

Mr. Raj (42) joined KrisEnergy in 2013 and is a qualified Chartered Accountant with the Chartered Accountants in Australia and New Zealand. He has more than 17 years of investment banking and oil and gas experience in the Asia Pacific region.

Mr. Raj started his career as a business analyst for a mid-sized Australian aerospace firm from 1994 until 1996. From 1996 until 2000, he was an integral senior member of the Corporate and Business Services division of international chartered accounting firm, Moore Stephens LLP. Mr. Raj moved to Singapore in 2000 and joined CLSA Merchant Bankers Limited ("CLSA") where he led the Southeast Asian investment banking execution business, including the IPO of Pearl Energy Ltd on the Singapore Exchange. At CLSA, Mr. Raj was the Director of Investment Banking and a member of the board of directors for CLSA Merchant Bankers Ltd, the CLSA entity regulated by the Monetary Authority of Singapore.

In 2009, Mr. Raj founded, and was Chief Executive Officer for Brighton Capital Advisors, a corporate finance and advisory firm established in Singapore with a primary focus on the oil and gas sector. Mr. Raj holds a Bachelor of Commerce majoring in Accounting and Finance from Monash University.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Brighton Capital Advisors Pte Ltd



JAMES PARKIN

VICE PRESIDENT EXPLORATION

Mr. Parkin (56) joined KrisEnergy in 2009 and has more than 30 years of experience in the upstream oil and gas sector, of which he has spent over 25 years in Southeast Asia. Prior to KrisEnergy, Mr. Parkin was Vice President Exploration from 2003 until 2009 and Regional Vice President, Southeast Asia (acting) from 2008 until 2009 for Pearl Energy.

He began his career in 1979 as a Mudlogger, later becoming a Wellsite Geologist with Exploration Logging International. From 1986 until 1990, he worked at British Gas as an Operations Geologist. In 1990, Mr. Parkin moved to Indonesia and worked as a Senior Geologist for Petromer Trend until 1993 and later became a Senior Exploration Geologist for Union Texas Petroleum and Far East Exploration Co. Ltd from 1997 until 1998. From 1998 until 2003, Mr. Parkin was a Senior Geologist and then Team Leader East Java at Gulf Indonesia/Conoco/ConocoPhillips.

Mr. Parkin holds a Bachelor of Science (Hons) in Geology from the University of Sheffield and a Master of Science in Petroleum Geology from the Imperial College of Science and Technology, University of London. Mr. Parkin is a member of the South East Asia Petroleum Exploration Society, Indonesian Petroleum Association and Petroleum Exploration Society of Great Britain.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



BRIAN HELYER

VICE PRESIDENT OPERATIONS

Mr. Helyer (57) has worked in the offshore oil and gas industry for over 30 years covering all aspects of project management for facilities construction, operations, maintenance and commissioning. He joined KrisEnergy in 2010 and is also responsible for the writing and implementation of EHSS policy across the group.

Prior to KrisEnergy, Mr. Helyer was the Project and Operations Director for Songa Floating Production, responsible for the conversion and class approval of the floating production, storage and offloading vessel, *FPSO East Fortune*. Between 2003 and 2007, he worked for Petrofac Energy Developments in various roles such as Production Manager, Business Development Manager and Project Manager in Indonesia, Malaysia, United Kingdom and Tunisia. From 1999 to 2005, Mr. Helyer was Field Operations Manager at the Kakap oil field in the South China Sea for Gulf Resources (Indonesia). He also spent 14 years with Marathon Oil in various roles in the United Kingdom and Indonesia.

Mr. Helyer has attained the National Examination Board in Occupational Safety and Health (NEBOSH) professional safety accreditation and is a member of the International Institute of Risk Management (IIRM) and the Institute of Occupational Safety and Health (IOSH).

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



TIM KELLY

VICE PRESIDENT ENGINEERING

Mr. Kelly (55) has more than 30 years of experience in the upstream oil industry with the last 25 years spent in Southeast Asia, during which time he has been involved in the appraisal and development of new fields and the reservoir and production management of mature fields.

Mr. Kelly was Corporate Petroleum Engineering Manager for Pearl Energy between 2003 and 2009 in Singapore and was involved in projects in Indonesia, Philippines, Thailand and Vietnam. Between 1989 and 2003, Mr. Kelly was based in Jakarta as Engineering Manager for Marathon Oil, Clyde Petroleum and Gulf Indonesia, and as DST Specialist with ExxonMobil. He began his career in 1981 with Phillips Petroleum as a Drilling & Reservoir Engineer working in the United States and Singapore.

Mr. Kelly holds a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines. He is a member of the Society of Petroleum Engineers and South East Asia Petroleum Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



KELVIN TANG

VICE PRESIDENT LEGAL PRESIDENT CAMBODIA

Mr. Tang (40) joined KrisEnergy in 2009 and is responsible for the legal and regulatory functions of the company. Since late 2014, Mr Tang has taken on the additional role of President of KrisEnergy's activities in Cambodia. Prior to KrisEnergy, Mr. Tang was based in Abu Dhabi as General Counsel for Aabar, having held the position of General Counsel and Company Secretary between 2005 and 2008 at Pearl Energy.

From 2003 until 2004, Mr. Tang was a Legal Associate for Wong Partnership LLP and Clifford Chance Wong (a joint law venture between Wong Partnership LLP and Clifford Chance Wong Pte Ltd). He was Associate Director (Legal) for Temasek Holdings Pte Ltd in 2002, and a Legal Associate in the Technology Practice Group of Rajah & Tann LLP between 2000 and 2002.

He holds a Bachelor of Law from the National University of Singapore and is an Advocate and Solicitor of the Supreme Court of Singapore. He is also a member of the Association of International Petroleum Negotiators.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
KrisEnergy (Ageng) B.V.; KrisEnergy (Andaman Timur) B.V.; KrisEnergy (Nemo) B.V.; KrisEnergy (Sakti) B.V.; KrisEnergy (Tanjung Aru) B.V.; KrisEnergy (Udan Emas) B.V.; KrisEnergy East Seruway B.V.; KrisEnergy Glagah-Kambuna B.V.; KrisEnergy (Andaman II) B.V.; KrisEnergy Kutai B.V.; KrisEnergy Kutei B.V.; KrisEnergy (Bangora) B.V.



JOHN BUJNOCH

VICE PRESIDENT DRILLING

Mr. Bujnoch (64) has over 40 years of experience in the offshore oil and gas industry, with over 30 years spent as a drilling engineer, rig site manager or in well operations management. He joined KrisEnergy in 2010 in a part-time capacity and became a full-time employee in 2011.

Mr. Bujnoch began his career in 1972 as a Meteorologist/Oceanographer consultant for the oil industry. He joined Conoco Inc. (now ConocoPhillips) as a Meteorologist/ Oceanographer in the Production Engineering Services group, primarily providing project environmental design criteria and also working on environmental issues and in-house hurricane warning services. In his ensuing 27 years with Conoco-Phillips, Mr. Bujnoch worked in various roles such as Rig Site Manager in Texas, Louisiana, and Gulf of Mexico from 1981 until 1984 and 1990 until 1995, respectively; Workover Engineer in Dubai from 1984 until 1990; Rig Site Manager in the UK North Sea from 1995 until 2000; Completion Specialist and Well Operations Coordinator in Indonesia from 2000 until 2006; and Drilling Superintendent in Qatar in 2006.

From late 2006 until 2009, Mr. Bujnoch was Vice President Drilling for Pearl Oil (Thailand), where he was responsible for exploration and development drilling in Thailand and Vietnam. During this period, the company drilled more than 100 wells in the region and brought four platforms into production.

Mr. Bujnoch holds a Bachelor of Arts in Meteorology from the University of St. Thomas in Texas and is a member of the Society of Petroleum Engineers.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Global Tender Barge Pte Ltd



MIKE WHIBLEY

VICE PRESIDENT TECHNICAL

Mr. Whibley (56) is a geologist with over 30 years of management, operational and interpretive experience in exploration and development projects and new business development. He has been based in Asia for more than 20 years.

Prior to joining KrisEnergy in 2009, Mr. Whibley held senior management and senior technical roles in Singapore with Pearl Energy/ Aabar/ Mubadala in Singapore between 2006 and 2009; in Jakarta, Indonesia with Amerada Hess from 2003 until 2006; Santa Fe Energy /Devon Energy/ PetroChina between 1998 and 2003, Santos Ltd. from 1997 until 1998; and Apache Corporation from 1993 until 1997.

Mr. Whibley worked in Perth, Australia originally with Phillips Petroleum as a Graduate Geologist from 1980 until 1983 and later with Bond Energy Resources/ Occidental Petroleum/ Hadson Energy between 1983 and 1993 as a Senior Explorationist.

Mr. Whibley graduated from the University of Western Australia with a Bachelor of Science (Hons) in Geology and is a member of the Indonesian Petroleum Association, South East Asian Exploration Society and American Association of Petroleum Geologists.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



STEPHEN CLIFFORD

CHIEF STRATEGY OFFICER VICE PRESIDENT FINANCE THAILAND

Mr. Clifford (54) is a Chartered Certified Accountant with more than 25 years of experience in the oil and gas industry. He is a founding member of KrisEnergy and joined in 2009 as Chief Financial Officer.

Prior to KrisEnergy, Mr. Clifford was appointed Chief Financial Officer for Pearl Energy, during which he also served as Group Financial Controller for the upstream division of parent company, Mubadala from 2007 until 2009. From 1989 until 2007, he held financial management and controller roles with Halliburton Company in Europe, Middle East, Africa, Asia and the United States.

Mr. Clifford holds a Bachelor of Arts in Business Studies from The Hatfield University.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



CHRIS WILSON

VICE PRESIDENT BUSINESS DEVELOPMENT

Mr. Wilson (43) joined KrisEnergy in 2009 and is a strategist responsible for the origination and execution of corporate and asset acquisitions for the group and in particular the valuation of new business opportunities.

Between 2003 and 2009, he was the in-house Financial Advisor for Pearl Energy, working on all aspects of fundraising and acquisition opportunity evaluation, including reserves-based lending facilities, pre-IPO private equity placements, the company's IPO in 2005 and all key asset acquisitions.

In 2002, Mr. Wilson was a consultant with the Asian Development Bank. From 1997 until 2001, he was Assistant Vice President in the Project Finance Group of ABN AMRO in Singapore focusing initially on project advisory transactions in the power sector and later moving into lending and advisory in the oil and gas sector. Mr. Wilson began his career in 1995 with Chase Manhattan Bank as a private equity analyst for Chase Capital Partners in Hong Kong before moving to Singapore to take up the role of Assistant Vice President in the Risk Asset Management Group.

Mr. Wilson holds a Bachelor of Arts in International Relations from the John Hopkins University, and a Master of Arts in China Studies from the Paul H. Nitze School of Advanced International Studies. He is a member of the Association of International Petroleum Negotiators and South East Asia Petroleum Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Panotech Pte Ltd; Chicane Pte Ltd (voluntarily wound up)



TANYA PANG

VICE PRESIDENT INVESTOR RELATIONS & CORPORATE COMMUNICATIONS

Ms. Pang (49) was initially a consultant to KrisEnergy in 2009 and became a full-time employee of the group in 2012. Ms. Pang has more than 25 years of experience in journalism and media/investor relations in the energy sector.

In 2009, Ms. Pang established a consultancy providing corporate communications, marketing, public relations and editorial services to clients including KrisEnergy, Schlumberger Business Consulting, Arawak Energy, Vitol and Atlantic Energy. From 2008 until 2009, she was with Arawak Energy Ltd, a dual-listed upstream company on the Toronto Stock Exchange and the London Stock Exchange, as General Manager Investor Relations based in London, United Kingdom. Ms. Pang was with Pearl Energy from 2005 until 2008, where she was responsible for investor relations and all internal and external communications. From 1994 until 2005, she was with Reuters news agency as a Journalist and worked on foreign assignments including five years as an International Correspondent in Oslo, Norway, and five years in Singapore as Editor-in-Charge, Energy for Asia Pacific. She began her career as Deputy Editor on a monthly science journal before moving to Platts, the oil price benchmarking agency in 1992.

Ms. Pang holds a Bachelor of Science (Hons) in Chemistry from the University of Sussex and is a member of the South East Asia Petroleum Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



EDWIN G. BOWLES

GENERAL MANAGER BANGLADESH

Mr. Bowles (61), a geologist, is an executive oil and gas industry professional with more than 35 years of experience in Malaysia, India, Pakistan, UK, Middle East, North Africa and Sub-Saharan Africa. The majority of his career has been spent with British Gas and its overseas subsidiaries. He joined KrisEnergy in 2014.

Key roles which he has held prior to KrisEnergy include Exploration Manager West Africa, General Manager Pakistan and Managing Director of Gujarat Gas Company, India (the largest independent Gas Distribution Company in India). In 2008, Mr. Bowles established RJ Energy, which acts as a strategic advisor to ministries, state oil companies and international oil companies. This followed an extensive assignment with the UK government as an advisor on oil and gas (Africa and Middle East), where he sat on several advisory energy groups including those for Libya, Morocco, Egypt and Nigeria.

Mr. Bowles holds a Bachelor of Science (Hons) in Geology from Southampton University and a Master of Science in Geology from Imperial College of Science and Technology, University of London. He is a member of the Petroleum Exploration Society of Great Britain, American Association of Petroleum Geologists and Geological Association.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
EP Energy Ltd; RJ Energy Ltd; SAER Ltd



MALIN ROS

GENERAL MANAGER CAMBODIA

Ms. Ros (49) has more than 20 years of experience in the upstream oil and gas industry. She started her career in 1992 as an Administrator in the Cambodian office of Enterprise Oil Exploration, a British exploration and production company.

Ms. Ros took over the role of Office Manager in 1997 and was Enterprise Oil's local representative in Cambodia from 1999 onwards. After Royal Dutch Shell's acquisition of Enterprise Oil in 2002, Ms. Ros joined Chevron Overseas Petroleum (Cambodia) Ltd as Country Manager and was responsible for local government relations, operations and community engagement.

Ms. Ros was appointed General Manager of KrisEnergy's Cambodian operations in October 2014 following the company's acquisition of Chevron's Cambodia unit.

Ms. Ros holds a Bachelor of Arts in Economics and a Master of Business Administration from the National University of Management in Phnom Penh. She is a member of the Society of Petroleum Engineers.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



KUSMUTARTO BASUKI

GENERAL MANAGER INDONESIA

Mr. Basuki (53) joined KrisEnergy in July 2010, bringing extensive local knowledge and experience in the upstream sector. He began his career in 1987 as a Consulting Engineer at PT. SUCOFINDO, a state-owned inspection, testing and certification company, and later became Vice President of the Mineral Service Division. In 2003, he joined Pearl Energy in Indonesia as General Manager until 2010.

He holds a Bachelor of Science in Chemical Engineering from Bandung Institute of Technology and has an MBA from the Institute Pengembangan Manajemen Indonesia. Mr. Basuki is a member of Indonesian Petroleum Association.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



PHATTARIN JIRAPO-JAPORN

GENERAL MANAGER THAILAND

Ms. Jirapojaporn (39) joined KrisEnergy in 2010. She holds an Executive Master of Business Administration from the Sasin Graduate Institute of Business Administration of Chulalongkorn University and started her career in 2001 as a business analyst with Thai Shell Exploration and Production. She later went on to work on contract analysis in procurement and contract management.

Between 2007 and 2009, she was a business analyst for Hess Corporation with a primary focus on oil and gas assets in Thailand. Prior to joining KrisEnergy, she was a senior manager of group financial planning and analysis at Thoresen Thai Agencies Plc, a strategic investment holding company with three primary business groups – Transport, Energy and Infrastructure.

Ms. Jirapojaporn also holds a Bachelor of Business Administration, Finance & Banking and a Master of Science in Computer Information Systems from Assumption University.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil



NGUYEN MANH HUYEN

GENERAL MANAGER VIETNAM

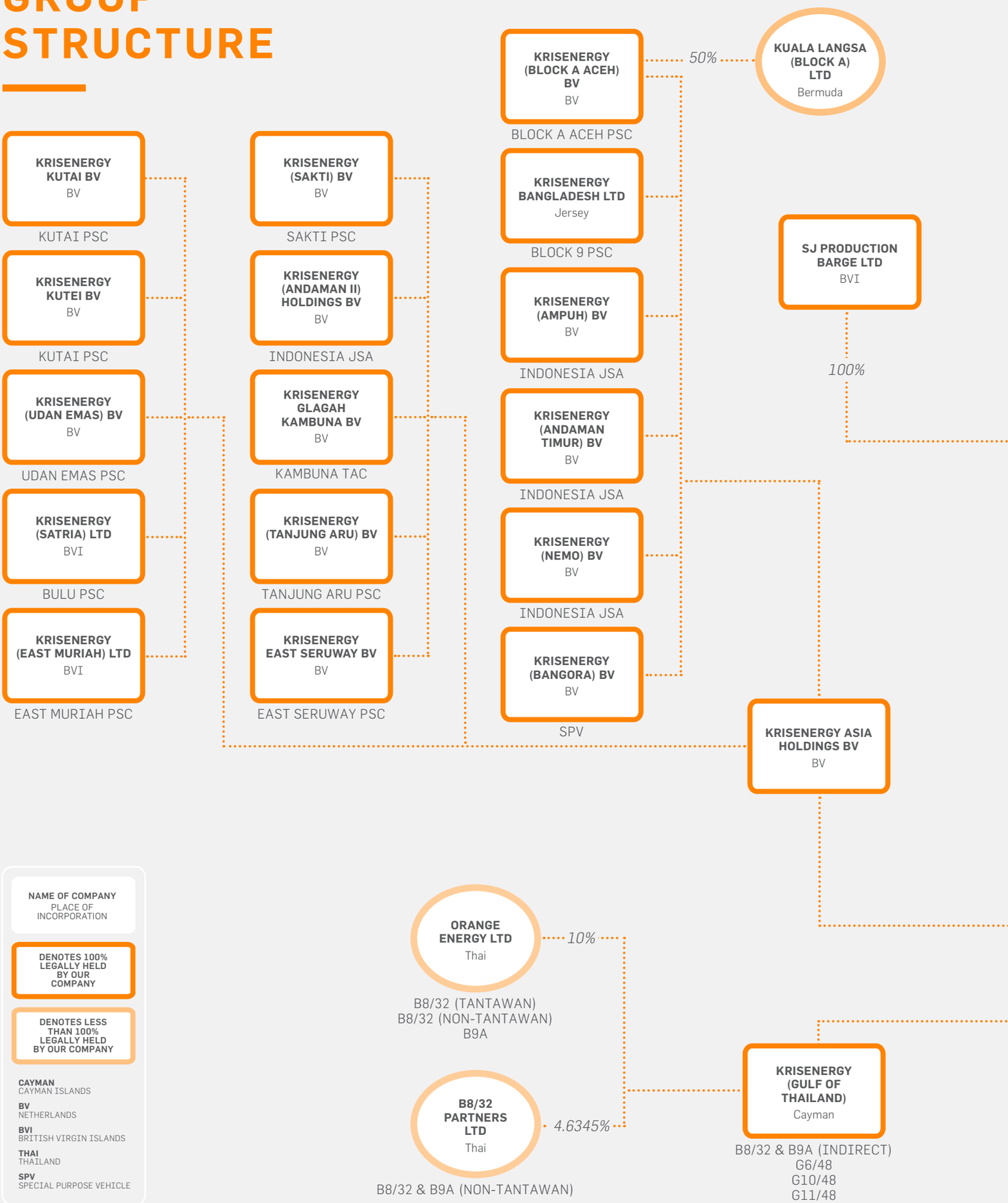
Mr. Huyen (65) has worked both as a geologist and a geophysicist. He has more than 40 years of experience, largely in Vietnam, but also in Southeast Asia, Middle East, North Africa and Russia. Mr. Huyen joined KrisEnergy in 2011.

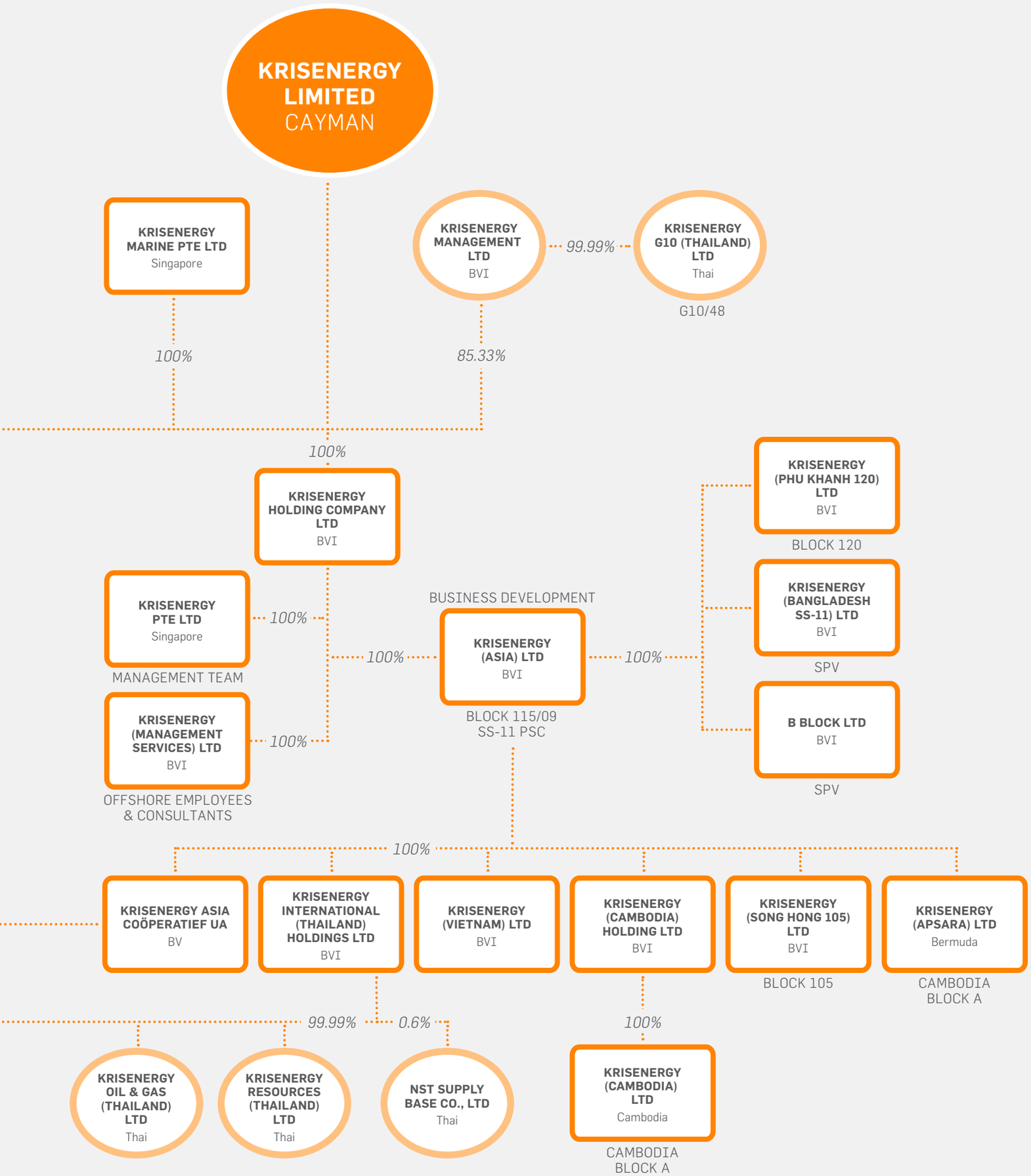
His previous positions include Party Chief for seismic acquisition, Seismic Interpreter; Researcher in geophysical methodology (Vietnam Petroleum Institute); Chief Geophysicist (American Red River Co. Petrovietnam Supervising Company (PVSC)); New Ventures Project Manager (PVSC); and Senior Manager for Exploration & Production (Petrovietnam Exploration & Production Company, formerly Petrovietnam Investment and Development Company (PIDC)). Prior to KrisEnergy, Mr. Huyen held the positions of Project Manager and General Manager for PIDC-Alger Company in Algeria and for Bach Dang POC.

Mr. Huyen has a Bachelor of Science in Geophysics from the University of Petroleum Geology in Bucharest, Romania. He was a collaborator with Moscow Geophysical Institute from 1983 until 1984 in Seismic Stratigraphy. He is a member of the Vietnam Geophysical Association and is a Committee Member of the Vietnam Petroleum Association. He has a number of reports and published research works relating to petroleum exploration and production.

Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):
Nil

GROUP STRUCTURE




KRISENERGY LIMITED
CAYMAN
KRISENERGY MARINE PTE LTD
Singapore
100%
KRISENERGY MANAGEMENT LTD
BVI
99.99%
KRISENERGY G10 (THAILAND) LTD
Thai
G10/48
85.33%
100%
KRISENERGY HOLDING COMPANY LTD
BVI
KRISENERGY PTE LTD
Singapore
100%
MANAGEMENT TEAM
KRISENERGY (MANAGEMENT SERVICES) LTD
BVI
100%
OFFSHORE EMPLOYEES & CONSULTANTS
100%
BUSINESS DEVELOPMENT
KRISENERGY (ASIA) LTD
BVI
100%
BLOCK 115/09 SS-11 PSC
100%
KRISENERGY (PHU KHANH 120) LTD
BVI
BLOCK 120
KRISENERGY (BANGLADESH SS-11) LTD
BVI
SPV
B BLOCK LTD
BVI
SPV
100%
KRISENERGY ASIA COÖPERATIEF UA
BV
KRISENERGY INTERNATIONAL (THAILAND) HOLDINGS LTD
BVI
KRISENERGY (VIETNAM) LTD
BVI
KRISENERGY (CAMBODIA) HOLDING LTD
BVI
KRISENERGY (SONG HONG 105) LTD
BVI
BLOCK 105
KRISENERGY (APSARA) LTD
Bermuda
CAMBODIA BLOCK A
99.99%
0.6%
KRISENERGY OIL & GAS (THAILAND) LTD
Thai
KRISENERGY RESOURCES (THAILAND) LTD
Thai
NST SUPPLY BASE CO., LTD
Thai
100%
KRISENERGY (CAMBODIA) LTD
Cambodia
CAMBODIA BLOCK A

CORPORATE GOVERNANCE REPORT

The Board and Management are committed to high standards of corporate governance, business integrity and professionalism in our activities. To this end, we are pleased to confirm that we have complied in all material aspects with the principles and guidelines of the Code of Corporate Governance 2012 (the "2012 Code"). Any deviations are accompanied with appropriate explanations within this corporate governance report. Our corporate governance practices are set out below, with specific reference to the 2012 Code.

PRINCIPLE 1 BOARD'S CONDUCT OF AFFAIRS

BOARD RESPONSIBILITY

The Board oversees the conduct of our affairs, exercising its fiduciary role in the interests of the Company and its subsidiaries (the "Group") as a whole, with the objectives of creating value for shareholders and ensuring sustainable success for the Group. The duties of the Board also include ensuring that corporate responsibility and the ethical standards of the Group are met. The Board is accountable for our activities, strategy and governance, risk management and financial performance. Specifically, its principal functions include:

- Setting our strategic direction and long-term targets and ensuring that resources are set aside to meet these targets
- Overseeing the business and affairs of the Company and instituting, with Management, strategies and financial objectives to be enforced by Management, and monitoring the performance of Management
- Approving the appointment of the Chief Executive Officer ("CEO") and Directors, and succession planning process
- Overseeing a framework for evaluating adequacy of the internal controls, risk management systems, financial reporting and compliance to safeguard shareholders' interests
- Setting the values and the standards (including ethical standards) of the Company
- Assuming responsibility for corporate governance
- Considering sustainability issues of policies and proposals.

INDEPENDENT JUDGEMENT

Directors are expected to exercise due diligence and independent judgement in the best interests of the Company.

DELEGATION BY OUR BOARD

The Board delegates authority and powers to various Board Committees to assist it in the oversight of specific responsibilities. These Committees have been constituted with clear written terms of references, in compliance with the 2012 Code, which set out the duties, authority and accountabilities of each Committee. Each Committee plays a pivotal role in ensuring good corporate governance practices within the Group.

MEETINGS & ATTENDANCE

The schedule of all Board and Board Committees meetings for the next calendar year is planned in advance, in consultation with our Directors. The Board meets at least four times a year and *ad hoc* as warranted by particular circumstances. Further, the non-executive Directors meet without the presence of Management at each of these Board meetings. Telephonic attendance and conference of Board meetings are allowed under our Articles of Association ("Articles").

The Board and Board Committees may also make decisions by way of circulating written resolutions.

During Board meetings, the Directors review our financial performance, annual budget, work program and budget, corporate strategy, business plans, potential acquisitions and significant operational matters. At each Board meeting, the Chairman of each Board Committee provides updates from their respective Board Committee meetings. In addition, the Board receives regular email and teleconference updates from the CEO on our operations, reports from the Chief Financial Officer ("CFO") on financial performance and where applicable, updates on developments in, and our compliance with, corporate governance requirements and other regulations.

The number of meetings held by the Board, Board Committees, non-executive Director meetings since 1 January 2014 to the end of the financial year under review, as well as the attendance of each member at these meetings, are disclosed in Table 1.

TABLE 1

	BOARD MEETINGS[1]	BOARD COMMITTEE MEETINGS[1]			NON-EXECUTIVE DIRECTORS' MEETING (WITHOUT PRESENCE OF MANAGEMENT)[5]
NAME OF DIRECTOR		AUDIT	NOMINATING	REMUNERATION	
Will Honeybourne	5	3[2]	4	3[2]	4
John Koh	5	4	4	2[3]	4
Keith Cameron	5	-	-	-	-
Chris Gibson-Robinson	5	-	-	-	-
Richard Lorentz	5	-	-	-	-
Brooks Shughart	5	4	3[2]	4	4
Choo Chiau Beng	4	2[4]	3	2[2]	3
Loh Chin Hua	4	0[4]	1[2]	4	3
Duane Radtke	5	1[4]	4	4	4
Jeff MacDonald	5	-	4	4	4
Tan Ek Kia	5	4	4	3[2]	4
Alan Nisbet[5]	3	3[4]	1[2]	2[3]	2
Keith Pringle[6]	3	3[4]	-	2[3]	2
Total No. Of Meetings Held	**5**	**4**	**4**	**4**	**4**

NOTES:
1. Refers to meetings held/attended while each Director was in office
2. By invitation
3. On 13 May 2014, John Koh ceased to be a member of the Remuneration Committee and Alan Nisbet and Keith Pringle were appointed as members of the Remuneration Committee
4. On 13 May 2014, Loh Chin Hua and Duane Radtke ceased to be members of the Audit Committee and Choo Chiau Beng, Alan Nisbet and Keith Pringle were appointed as members of the Audit Committee
5. Alan Nisbet was appointed to the Board on 13 May 2014 and will be seeking re-election as Director at the Annual General Meeting
6. Keith Pringle was appointed to the Board on 13 May 2014 and will be seeking re-election as Director at the Annual General Meeting

Further, the independent Directors hold their meetings after each of the Board meetings.

If a Director is unable to attend a Board or Board Committee meeting, he will receive materials for discussion and is expected to review them and subsequently advise the Chairman or Board Committee Chairman of his views and comments so that they can be conveyed to other members at the meeting.

BOARD APPROVAL

We have adopted internal guidelines that set forth matters requiring Board approval. Matters specifically reserved to our Board for approval, amongst others, are: (a) acquisitions and disposals of petroleum assets, (b) plan of development of petroleum assets, (c) amendment of the Group work program and budget, and (d) all commitments to term loans and lines of credit from banks and financial institutions by the Company. While matters relating to the above require the Board's direction and approval, Management is responsible for the day-to-day operation and administration of the Company.

BOARD INDUCTION

A formal letter will be sent to newly-appointed Directors upon their appointment detailing the duties and responsibilities of a Director. Newly-appointed Directors shall undergo an orientation program, which includes Management's introduction to our business, strategic plans and objectives and governance practices, amongst others. The orientation program serves as comprehensive and tailored induction and training.

BOARD TRAINING

The Directors are encouraged to keep abreast of the relevant topics such as Directors' duties and responsibilities, corporate governance, changes in financial reporting standards, insider trading and changes in industry-related matters. As and when available, relevant reading materials are sent to the Directors. Directors are also kept informed of, and encouraged to attend, any appropriate and pertinent courses which may serve to update and refresh them on matters, which can affect or enhance their performance as Board or Board Committee members. In addition, it is our policy to arrange for the Directors to attend a yearly training session on such topics conducted by an external expert. Former topics covered during such training sessions include corporate governance updates, anti-bribery and corruption laws and insider trading laws.

PRINCIPLE 2
BOARD COMPOSITION AND GUIDANCE

BOARD SIZE, COMPOSITION & COMPETENCY

The size and the composition of the Board are reviewed regularly and at least annually by the Nominating Committee, with the aim to maintain a size which is conducive and effective for discussion and decision making, while ensuring that the Board has sufficient independent Directors. The Nominating Committee emphasises the need for the Directors to possess a wide array of expertise, skills and attributes, including relevant core competencies in areas such as accounting and finance, business and management, industry knowledge, strategic planning and knowledge of risk management and takes these factors into account when recommending Director appointments. The Board, with the concurrence of the Nominating Committee, taking into account the current nature and scope of our operations, the requirements of our business, and the need to avoid undue disruptions from changes to the composition of the Board and Board Committees, considers that the current size and composition provides an appropriate balance and diversity of skills, experience and knowledge of the Company without interfering with efficient and effective decision-making. Nonetheless, the Board, together with the Nominating Committee, will continue to evaluate the Board size, composition and competency on a regular basis to cater for the evolving needs of the Company and the industry.

BOARD INDEPENDENCE

An annual review is conducted by the Nominating Committee to determine whether each Director is independent, taking into account the 2012 Code definition of an "independent" Director and guidance as to relationships the existence of which would deem a Director not to be independent. In this regard, the Nominating Committee takes into consideration, among other things, whether a Director has business relationships with the Company or any of its related companies, and if so, whether such relationships could interfere, or be reasonably perceived to interfere with the exercise of the Director's independent judgement with a view to the best interests of the Company. The Board, taking into account the views of the Nominating Committee, considers the following Directors independent: John Koh, Duane Radtke, Jeff MacDonald, Tan Ek Kia, Alan Nisbet and Keith Pringle.

BOARD INFORMATION

We endeavour to provide an open and constructive environment for the Board members to have the freedom to debate and challenge Management on its assumptions and proposals. This is an underlying feature of a robust and effective Board and mandatory for good corporate governance. The Board, and in particular, the non-executive Directors, are kept well informed of our conduct of business and affairs through regular updates from Management and are knowledgeable about the oil and gas industry. The non-executive Directors are supported by accurate and timely information and are granted unrestricted access to Management. Further, if possible, regular informal meetings are held by Management to brief the Directors on prospective transactions and potential developments at an early stage prior to seeking formal Board approval and these are usually accompanied with detailed Board memorandums. Technical Board meetings are also conducted for the Directors to be kept updated on relevant in-depth information in relation to our operations, which gives the Directors better understanding of the Group and its businesses and to provide the opportunity for them to familiarise themselves with Management.

PRINCIPLE 3
CHAIRMAN AND CEO

SEPARATION OF THE ROLES OF CHAIRMAN & CEO

Will Honeybourne is the non-executive Chairman, and Keith Cameron is the CEO. The roles of the Chairman and CEO are kept separate to ensure an appropriate balance of power, greater accountability and increased capacity of the Board for independent decision-making. The Chairman is not related to the CEO. The division of responsibilities and functions between the two roles has been delineated and agreed by the Board.

The Chairman guides the Board to ensure its effectiveness on all aspects of its role, sets the agenda and monitors the flow of information from Management to the Board to ensure that all material information is provided in a timely manner for the Board to review and discuss. He encourages and promotes communication and constructive relations between the Board and Management, and between our executive and non-executive Directors. The Chairman aims to take a lead role in spearheading high standards of corporate governance, with the aid of the Directors, Company Secretaries and Management.

The CEO manages and oversees our business. The other executive Directors and Management provide assistance to the CEO in making strategic proposals to the Board. Pursuant to open and constructive Board discussions, the CEO formulates the plan to execute the agreed strategy and implements the Board decisions.

LEAD INDEPENDENT DIRECTOR

John Koh is the lead independent Director. The lead independent Director is appointed by the Board to lead in the coordination of activities for the non-executive Directors in instances where it would not be appropriate for the Chairman to serve in such capacity. The lead independent Director also assists the Chairman and Board to ensure effective corporate governance measures are practised when managing the affairs of the Company. The independent Directors meet periodically and the lead independent Director will provide feedback to the Chairman after such meetings.

He is available to shareholders if they have concerns which contact through the normal channels of the Chairman, CEO and CFO have failed to resolve or is inappropriate.

PRINCIPLE 4
BOARD MEMBERSHIP

NOMINATING COMMITTEE

The Nominating Committee is chaired by Tan Ek Kia and comprises Will Honeybourne, John Koh, Choo Chiau Beng, Duane Radtke and Jeff MacDonald. The Nominating Committee comprises entirely of non-executive Directors, of which four out of six (including the Nominating Committee Chairman) are independent.

The key responsibilities of the Nominating Committee include:

- Reviewing and recommending candidates for appointment to the Board and Board Committees, as well as candidates for senior management staff
- Developing a process for evaluation of the performance of the Board, Board Committees and Directors
- Reviewing and recommending nomination for re-appointment or re-election or renewal of appointment of the Directors
- Reviewing Board succession plans for the Directors, in particular the Chairman and CEO

- Reviewing training and professional development programs for the Board
- Determining the independence of the Directors
- Reviewing the participation by each independent Director in any competing businesses and taking into account such matters in the re-appointment or re-election or renewal of appointment of such independent Director.

RECOMMENDATION OF DIRECTORS

It is the responsibility of the Nominating Committee to review and recommend all nominations and re-nominations of Directors and Board Committee members, taking into account the composition and progressive renewal of the Board and each Director's competencies, commitment, contribution and performance. Under our Articles, the Directors are required to retire at least once every three years. For this purpose, we adopt a policy of retiring one-third of our Directors from office by rotation at each Annual General Meeting ("AGM") and these Directors will be eligible for re-election at that AGM. Our Articles also stipulate that Directors appointed by the Board during the financial year, shall only hold office until the next AGM, and thereafter be eligible for re-election at the AGM.

REVIEW OF DIRECTORS' INDEPENDENCE

The Nominating Committee also undertakes the responsibility of determining the independence of the Directors on an annual basis. Please refer to *Principle 2 "Board Composition and Guidance"* of this Corporate Governance Report for the Nominating Committee's determination of Directors' independence.

DIRECTORS' TIME COMMITMENTS

The Nominating Committee considers whether Directors, who have multiple board representations, are able to devote sufficient time and attention to discharging their responsibilities adequately. The Nominating Committee believes that limiting the number of directorships which a Director can hold is arbitrary and given that time requirements for each role may differ, there should be no prescriptive maximum limit set. The Nominating Committee requires each Director to confirm annually to the Nominating Committee, his ability to devote sufficient time and attention to the Company's affairs, having regard to all his other commitments (specifically considering factors such as executive duties or listed company representations). The Nominating Committee is satisfied that all Directors have discharged their duties adequately from 1 January 2014 to the end of the financial year under review and will continue to do so for the next financial year.

ALTERNATE DIRECTORS

We do not have a practice of appointing alternate Directors.

SUCCESSION PLANNING FOR THE BOARD & MANAGEMENT TEAM

We place emphasis on succession planning and the Nominating Committee seeks to refresh the Board membership progressively and in an orderly manner. The Nominating Committee reviews the succession and leadership development plans for the Board and Management, which are subsequently approved by the Board.

CRITERIA AND PROCESS FOR NOMINATION AND SELECTION OF NEW DIRECTORS & RE-ELECTION OF CURRENT DIRECTORS

In the search, nomination and selection of new Directors, the Nominating Committee identifies the main attributes which an incoming Director should have, based on the current matrix of the attributes of the existing Board and the requirements of the Company. Once the Board approves the identification of such main attributes, the Nominating Committee taps on the resources of the Directors' personal and business contacts and recommendations of candidates and goes through a shortlisting process. Executive recruitment agencies may also be used where necessary. Interviews will be arranged with potential candidates for the Nominating Committee members for assessment. The Nominating Committee will then recommend the candidate for appointment to the Board. When reviewing the suitability of a current Director for re-election, the Nominating Committee assesses the Director for his skills, and the time and experience he has and can contribute to the Board and Company, and takes into consideration the other time commitments of that Director.

KEY INFORMATION ON DIRECTORS

Please refer to the section *Board of Directors* of this Annual Report for key information on our Directors. The *Notice of Annual General Meeting* sets out the Directors proposed for retirement and re-election at the AGM.

PRINCIPLE 5 BOARD PERFORMANCE

BOARD EVALUATION POLICY

The Board has implemented a process for assessing the effectiveness of the Board and Board Committees, which will be carried out by the Nominating Committee. To ensure that the assessments are completed promptly, fairly and confidentially, an independent consultant has been engaged by the Nominating Committee to assist in collating and analysing the feedback from the Board members.

The evaluation process will comprise questionnaires designed with the assistance of the independent consultant. The questionnaires will be developed through incorporating best practices in the market for Director, Board and Board Committee evaluations and revised based on key issues and areas which the Board wishes to focus on. Such questionnaires will be provided to the Directors for feedback on an annual basis and the results will be collated by the independent consultant and presented to the Nominating Committee. The Nominating Committee will then assess and discuss such evaluation results and will ascertain the main components for improvement and map out the key action steps.

BOARD AND COMMITTEES EVALUATION PROCESS

For the financial year under review, the Directors were provided a set of questionnaires to evaluate the effectiveness and adequacy of the performance of the Board and the relevant Board Committees which they are a member of. The Nominating Committee discussed the results of such evaluations internally and subsequently with the Board. The evaluation results of the Board and Board Committees were satisfactory, with a consensus that appropriate measures had been and will be undertaken to fortify the governance of the Company, the Board and Board Committees. Areas such as succession planning for certain Senior Management roles were highlighted for discussion and will be continually addressed throughout the financial year with a view to improve the effectiveness and adequacy of the performance of the Board and Board Committees.

BOARD AND COMMITTEES PERFORMANCE CRITERIA

The performance criteria for the evaluations (which was approved by the Board) included the size and composition, independence, processes, information and accountability, risk controls and internal management, standards of conduct, all of which are in accordance with the guidelines of the 2012 Code and the terms of reference of each of the Committees.

PRINCIPLE 6 ACCESS TO INFORMATION

COMPLETE, ADEQUATE & TIMELY INFORMATION

The flow of complete, adequate and timely information on an ongoing basis to the Board is essential for its discharge of its duties. Board meeting agendas and Board papers are sent in advance with items proposed by Management and the relevant Chairman, so that the Directors have the requisite amount of time to consider the matters to be discussed. This enables discussions during the meeting to focus on questions which may arise. Any additional material or information requested by the Directors is promptly furnished. During Board meetings, Management personnel who are able to provide insight into the matters at hand will be requested to join. Directors are also acquainted with the relevant Management personnel, Company Secretaries, internal and external auditors to facilitate direct and independent access to the same.

Board meeting agendas and Board papers include, amongst others, minutes to the previous Board meetings, major operational and financial updates, background or explanations on matters brought before the Board for decision or information, including issues dealt with by Management, relevant budgets, forecasts and projections. In respect of budgets, any material variance between the projections and actual results is disclosed and explained to the Board.

Pursuant to our corporate governance practices, key matters requiring decisions are reserved for resolution at Board meetings or teleconferences. Relevant material information on the Group is forwarded to the Directors on an ongoing basis.

COMPANY SECRETARY

The Company Secretary administers, attends and prepares minutes of Board proceedings, ensuring that Board procedures are followed and that applicable rules and regulations are complied with. The Company Secretary attends meetings for the Board and Board Committees. The Chairman works with the Company Secretary to ensure that there is good information flow within the Board and its Committees and between Management and non-executive Directors, as well as to facilitate orientation and assist with professional development of the Directors as necessary. The Company Secretary also assists the Chairman and Board to implement and strengthen corporate governance practices and processes. The responsibility of compliance lies with the Company Secretary and guidance is provided to Management to ensure that our Articles and relevant rules and regulations are complied with. The Company Secretary acts as the primary conduit for communication between the Company and the SGX-ST, where necessary. The appointment or removal of any Company Secretary is subject to the approval of the Board.

INDEPENDENT PROFESSIONAL ADVICE

Directors are able to seek and obtain independent professional advice to assist them in their duties, at the expense of the Company, where necessary.

PRINCIPLE 7 REMUNERATION MATTERS

REMUNERATION COMMITTEE

The Remuneration Committee is chaired by Jeff MacDonald and comprises Brooks Shughart, Loh Chin Hua, Duane Radtke, Alan Nisbet and Keith Pringle. The Remuneration Committee comprises entirely of non-executive Directors, of which four out of six (including the Remuneration Committee Chairman) are independent.

The key responsibilities of the Remuneration Committee include:

- Reviewing and approving our policy for determining the remuneration of its executives including that of executive Directors, CEO and other key Management personnel ("Senior Management")
- Reviewing the ongoing appropriateness and relevance of our executive remuneration policy and other benefit programs
- Considering, reviewing and approving and/or varying the entire specific remuneration package and service contract terms for each Senior Management
- Considering and approving termination payments, retirement payments, gratuities, *ex-gratia* payments, severance payments and other similar payments to Board members and Senior Management
- Reviewing the Group's obligations arising in the event of termination of Senior Management's contracts of service;
- Reviewing and approving the design of all option plans, stock plans and/or other equity-based plans
- Determining each year whether awards will be made under each of the equity-based plans
- Reviewing and approving each award as well as the total proposed awards under each plan in accordance with the rules governing each plan
- Reviewing, approving and keeping under review performance hurdles and/or fulfilment of performance hurdles of each of the equity-based plans
- Approving the remuneration framework (including Directors' fees) for non-executive Directors
- Reviewing succession plans for Senior Management positions.

No member of the Remuneration Committee is involved in deliberations in respect of any remuneration, compensation, options or any form of benefits to be granted to him.

The Remuneration Committee reviews and recommends to the Board remuneration packages, annual increments, variable bonuses, performance share grants and other incentive awards or benefits. Where necessary, the Remuneration Committee may seek advice from independent expert remuneration consultants on remuneration matters. Please refer to *Principle 9 "Disclosure on Remuneration"* of this Corporate Governance Report for further information on our compensation philosophy.

PRINCIPLE 8
LEVEL AND MIX OF REMUNERATION

REMUNERATION OF EXECUTIVE DIRECTORS & KEY MANAGEMENT PERSONNEL

The remuneration packages of Senior Management comprise the following components:

(a) Fixed and Variable Components

The fixed component consists of basic salary and Central Provident Fund contributions (if applicable). The Remuneration Committee ensures that Senior Management's remuneration is consistent and comparable with market practice by reviewing and considering such remuneration components against those of comparable companies, if such information is publicly available, while continuing to be aware of the general correlation between increased remuneration and performance improvements.

The variable component comprises variable bonus based on our Group's performance in relation to stipulated key performance indicators, as well as relevant market remuneration benchmarks. The performance of Senior Management is assessed each year, measuring their performance against such selected key performance indicators. Total bonuses payable are reviewed by the Remuneration Committee and approved by the Board to ensure (i) alignment of interests with those of shareholders, (ii) symmetry with risk outcomes, and (iii) sensitivity to time horizon of risks.

The Board views performance bonus as a mechanism to support the Group's business strategy and the enhancement of shareholder value through the delivery by the Group of annual financial, strategic and operational objectives. On an individual level, the performance bonus may vary based on the actual achievement of the Group and individual performance objectives. While these objectives may be of different emphasis for each executive, they are assessed on the same principles across our business and strategy targets, which include environmental, health and safety processes, production and reserves values, financial and risk management and people development. Further, our executives may be assessed on teamwork and collaboration across the Group.

(b) Allowances & Benefits

Allowances and benefits provided are consistent with market practice and include medical benefits, flexible benefits and transportation and education allowances. Eligibility for these allowances and benefits will depend on individual salary grade, employment position and country of residence.

(c) Share Awards & Options

In recognition of the contribution of Senior Management to the Company and as a tool for long-term incentive, Senior Management is also eligible for share options and awards under the KrisEnergy Employee Share Option Scheme ("KrisEnergy ESOS") and KrisEnergy Performance Share Plan ("KrisEnergy PSP").

For the financial year under review, awards were granted under the KrisEnergy PSP at the discretion of the Remuneration Committee to Senior Management. Such share awards are conditional upon the achievement of predetermined performance targets over the performance period. These performance conditions include market capitalisation and reserves targets, which were intended to serve as incentives to Senior Management to create value for the Company and align their interests with the Group's business objectives. As at the end of the financial year, certain share awards granted under the KrisEnergy PSP have been partially vested.

For more information on the KrisEnergy ESOS and KrisEnergy PSP and the share awards granted, please refer to the sections *Directors' Report – KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan* and *Notes to the Consolidated Financial Statements – Share-based Payments* of this Annual Report.

The Remuneration Committee has the discretion not to award performance bonuses or share-based incentives in any year if any executive is involved in misconduct which has a material impact on the Company.

REMUNERATION OF NON-EXECUTIVE DIRECTORS

Directors' fees payable to the non-executive Directors are paid in cash and are subject to shareholders' approval at each AGM. Each non-executive Director is paid a basic fee and an attendance fee. The Chairman of the Board and each Board Committee Chairman command an additional fee in addition to the membership fees in view of the greater responsibility carried by that office. Executive Directors are not paid Directors' fees.

Basic Fee

The basic fee structure of the non-executive Directors is as disclosed in Table 2 below:

TABLE 2

NATURE	DESCRIPTION	RATE
Board Fees	Chairman Fee	US$20,000 Per Annum
	Basic Retainer Fee	US$50,000 Per Annum
	Lead Independent Director Fee	US$10,000 Per Annum
Audit Committee Fees	Membership Fee	US$10,000 Per Annum
	Chairman Fee	US$10,000 Per Annum
Remuneration Committee Fees	Membership Fee	US$10,000 Per Annum
	Chairman Fee	US$10,000 Per Annum
Nominating Committee Fees	Membership Fee	US$10,000 Per Annum
	Chairman Fee	US$10,000 Per Annum

If a Director occupies a position for part of the financial year, the fee payable will be pro-rated accordingly.

Attendance Fee

A non-executive Director will be paid an attendance fee of US$10,000 for each Board meeting attended (whether in person or by teleconference) in that financial year and also be reimbursed any travel expenses incurred in relation thereto. No attendance fee is payable for attendance of (i) routine Board telephone conference calls or (ii) Board Committee meetings.

Share Awards & Options

Non-executive Directors are eligible for the grant of share options and awards under the KrisEnergy ESOS and KrisEnergy PSP and are also encouraged to acquire Shares in order to align their interests with that of our shareholders. Directors' shareholding interests are disclosed in the section *Directors' Report – Directors' Interests in Shares and Debentures* of this Annual Report. For the financial year under review, non-executive Directors will not receive any Shares as part of their remuneration. However, the Remuneration Committee will review and consider the possibility of including a share-based component in the non-executive Directors' remuneration for future years.

PRINCIPLE 9 DISCLOSURE ON REMUNERATION

ANNUAL REMUNERATION REPORT

A breakdown showing the level and mix of each individual Director's and Senior Management's remuneration payable for the financial year under review is disclosed in Tables 3A, 3B and 4 below:

TABLE 3A — EXECUTIVE DIRECTORS

NAME OF DIRECTOR	SALARY INCLUDING CPF, IF ANY	BONUS/ PROFIT-SHARING	ALLOWANCES & OTHERS	DIRECTORS' FEES	PERFORMANCE SHARES	TOTAL
	%	%	%	%	%	%
S$1,250,001 TO S$1,500,000						
Keith Cameron	50	26	17	–	7	100
Chris Gibson-Robinson	50	26	17	–	7	100
Richard Lorentz	50	26	17	–	7	100

TABLE 3B — NON-EXECUTIVE DIRECTORS

Directors' fees paid to the non-executive Directors for services for the financial year ended 31 December 2014 were US$1,153,458.90 (S$1,499,496.57).

NAME OF DIRECTOR	DIRECTORS' FEES (US$)
Will Honeybourne	130,000
John Koh	145,000
Brooks Shughart	120,000
Choo Chiau Beng	102,500
Loh Chin Hua	102,500
Duane Radtke	122,500
Jeff MacDonald	130,000
Tan Ek Kia	130,000
Alan Nisbet[1]	85,479.45
Keith Pringle[1]	85,479.45

NOTE:

1 Alan Nisbet and Keith Pringle were appointed to the Board on 13 May 2014

We believe that disclosure of (i) precise remuneration amounts of individual Executive Directors and Senior Management, and (ii) aggregate total remuneration paid to Senior Management is disadvantageous to our business interests, in view of the shortage of talented and experienced personnel in the upstream oil and gas industry.

No termination, retirement or post-employment benefits have been granted to the Directors or Senior Management.

REMUNERATION OF EMPLOYEES WHO ARE IMMEDIATE FAMILY MEMBERS OF A DIRECTOR OR CEO

No employee of the Company and its subsidiaries is an immediate family member of a Director or the CEO.

The remuneration packages of the Directors and Senior Management have been reviewed and approved by the Remuneration Committee, having regard to their contributions as well as the financial performance and commercial needs of the Group. The Remuneration Committee is satisfied and has ensured that the Directors and Senior Management are adequately but not excessively remunerated.

DETAILS OF THE KRISENERGY ESOS & KRISENERGY PSP

For more information on the KrisEnergy ESOS and KrisEnergy PSP, please refer to the sections *Directors' Report – KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan* and *Notes to the Consolidated Financial Statements – Share-based Payments* of this Annual Report, respectively.

TABLE 4 — SENIOR MANAGEMENT

NAME OF EXECUTIVE	DESIGNATON	BASED / FIXED SALARY INCLUDING CPF, IF ANY	BONUS / PROFIT-SHARING	ALLOWANCE & OTHERS	PERFORMANCE SHARES	TOTAL
		%	%	%	%	%
S$1,000,001 TO S$1,250,000						
Kiran Raj	Chief Financial Officer	51	25	17	7	100
James Parkin	Vice President Exploration	51	25	17	7	100
Brian Helyer	Vice President Operations	51	25	17	7	100
Tim Kelly	Vice President Engineering	51	25	17	7	100
Kelvin Tang	Vice President Legal, President Cambodia	51	25	17	7	100

PRINCIPLE 10 ACCOUNTABILITY AND AUDIT

ACCOUNTABILITY & AUDIT

The Board understands its responsibility and adopts a balanced and understandable assessment of our performance, position and prospects when presenting interim and other price-sensitive public reports and reports to regulators (if required). Our affairs are conducted openly and transparently, whilst preserving our commercial interests. Financial statements and reports, along with all other price sensitive information, are released to our shareholders through timely announcements on SGXNET, press releases, our website and during media and analyst briefings. The Board is provided with updates and reports of our performance, position and prospects on a monthly basis and as the Board may require from time to time. The Board also takes steps to ensure compliance with legislative and regulatory requirements, including requirements under the listing rules. Regular updates on any material changes in the relevant legislative and regulatory framework are sent to the Board to keep them apprised.

PRINCIPLE 12 AUDIT COMMITTEE

AUDIT COMMITTEE

The Audit Committee is chaired by John Koh and comprises Brooks Shughart, Choo Chiau Beng, Tan Ek Kia, Alan Nisbet and Keith Pringle. The Audit Committee comprises entirely of non-executive Directors, of which four out of six (including the Audit Committee Chairman) are independent.

The key responsibilities of the Audit Committee include:

- Reviewing all financial information and any public financial reporting with Management and external auditors for submission to the Board
- Reviewing significant financial reporting issues and judgements so as to ensure the integrity of the financial statements of the Company and any announcements relating to the Company's financial performance;
- Reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from Management on difficulties which they have encountered with Management in the course of their audit
- Reviewing with external and internal auditors and reporting to the Board at least annually the adequacy and effectiveness of the internal control system, including financial, operational, compliance and information technology controls (such review can be carried out internally or with the assistance of any competent third parties)
- Reviewing with internal auditors, the program, scope of results of the internal audit and Management's response to their findings to ensure that appropriate follow-up measures are taken
- Reviewing at least annually, the adequacy and effectiveness of the internal audit function
- Reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors
- Reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information
- Reviewing interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interest have been put in place
- Assessing the suitability of an accounting firm as external auditors and recommending to the Board the appointment or re-appointment of such external auditors, approving their compensation and reviewing and approving their discharge
- Reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure
- Commissioning and reviewing the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material
- Reviewing risk management policies and guidelines and monitoring compliance therewith
- Reviewing and approving all hedging policies and types of hedging instruments
- Reviewing whistle-blowing policies and arrangements
- Reporting to the Board the work performed by the Audit Committee in carrying out its functions
- Monitoring the investments in the customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management of or have shareholding interests in similar or related business of the Company and making assessments on whether there are any potential conflicts of interests
- Undertaking generally such other functions and duties as may be requested by the Listing Manual of the SGX-ST and by amendments made thereto.

The Audit Committee has express authority to investigate any matter within its responsibilities and has full access to and cooperation from Management. It also has full discretion to invite any Director or Management personnel to attend its meetings, and reasonable resources to enable it to discharge its functions properly. The Audit Committee may also examine any other aspects of the Group's affairs, as it deems necessary where such matters relate to exposure or risk of a regulatory or legal nature, and monitor the Group's compliance with its legal, regulatory and contractual obligations. The Audit Committee regularly meets with the external auditors and internal auditors, in each case without Management's presence and at least once annually.

The Board is of the view that the Audit Committee members (including the Audit Committee Chairman) have recent and relevant accounting and related financial management expertise and are familiar with the Group's business and operations and are thus able to discharge their duties as Audit Committee members.

EXTERNAL AUDITORS

The Audit Committee recommends to the Board the appointment, re-appointment and removal of the external auditors, the remuneration and terms of engagement of the external auditors. The re-appointment of the external auditors is always subject to shareholder approval at our AGM.

During the financial year under review, the Audit Committee held quarterly meetings with the external auditors, without the presence of Management. The Audit Committee reviewed the independence and objectivity of the external auditors through discussions with the external auditors as well as a review of the volume and nature of non-audit services provided by the external auditors during the financial year under review. Based on the review, the Audit Committee is satisfied that the financial, professional and business relationships between the Company and the external auditors will not prejudice their independence and objectivity. Accordingly, the Audit Committee has recommended the re-appointment of the external auditors at the coming AGM.

In the review of the financial statements for the financial year under review, the Audit Committee held discussions with Management and the external auditors enquiring the accounting principles which were applied and their judgement of items that may affect the integrity of the financial statements. Subsequently, the Audit Committee recommended to the Board the release of the full year financial statements.

The total fees paid to our external auditors, Ernst & Young LLP, are as disclosed in Table 5 and the note summarises the various non-audit services provided:

TABLE 5

	S$'000	% OF TOTAL FEES PAID
EXTERNAL AUDITOR FEES FOR FY2014		
Total Audit Fees	415	78.9
Total Non-Audit Fees[1]	111	21.1
Total Fees Paid	**526**	**100**

NOTE:
[1] Non-audit services provided by Ernst & Young LLP include the advisory services in relation to (i) our bond issuances in June 2014 and August 2014 and (ii) tax filing and transfer pricing study

We have complied with Rules 712 and 715 of the Listing Manual of the SGX-ST in the appointment of our external auditors.

WHISTLE-BLOWING POLICY

Clearly defined procedures have been established to encourage employees, customers and third parties to report malpractices and misconduct in the workplace. Concerns about possible improprieties in matters of financial reporting, fraudulent acts and other matters in breach of company policies can be raised confidentially and arrangements are in place for investigations of such matters and for appropriate follow-up action. These procedures aim to promote fairness and consistency in dealing with concerns made in good faith.

There were no whistle-blowing reports made during the financial year under review.

INTERESTED PERSON TRANSACTIONS POLICY

We have embedded procedures to comply with the requirements of the Listing Manual of the SGX-ST relating to interested person transactions. All new Directors are briefed on the relevant provisions with which they are required to comply. Any interested person transactions are reported to and monitored by the finance department, and reviewed by the Audit Committee. There were no interested person transactions amounting to more than S$100,000 for the financial year under review.

MATERIAL CONTRACTS (RULE 1207(8) OF THE LISTING MANUAL OF THE SGX-ST)

There were no material contracts entered into by the Company or any of its subsidiaries involving the interest of the CEO, any Director, or controlling shareholder subsisting at the end of the financial year under review.

PRINCIPLES 11 & 13 RISK MANAGEMENT & INTERNAL CONTROLS, INTERNAL AUDIT

RISK MANAGEMENT & INTERNAL CONTROLS

It is the responsibility of the Board to ensure that there are sufficient risk governance measures implemented in the Company. The Board is also responsible for ensuring that Management maintains a sound system of risk management and internal controls to safeguard shareholders' investments and our assets. Risk management is a continual process in which Senior Management and operational managers continuously participate to evaluate, monitor and report to the Audit Committee and the Board on significant risks encountered in our operations.

We have developed and implemented a Board Assurance Framework ("Framework"), which includes an enterprise risk management framework. The Framework acts as the platform for identification of significant and material risks, to measure the potential impact and likelihood of those risks occurring, to test the internal control effectiveness and to create any action plans to further mitigate those risks. The risks identified in the Framework include strategic, financial, operational, compliance and information technology risks. We have also developed a risk governance structure, which provides details on the roles and responsibilities for the Board and Management (including the Chief Risk Officer) in risk monitoring, escalation, mitigation and reporting.

We have established risk appetite statements with tolerance limits to monitor shifts in significant risks and to proactively manage them within acceptable levels. These risk appetite statements have been reviewed and approved by the Audit Committee and the Board and will be monitored on a quarterly basis. In addition, the Board has received assurance from the CEO and CFO that our financial records have been properly maintained and give a true and fair view of our operations and finances, and that we have effective risk management and internal control systems.

The Audit Committee, as delegated by the Board, has the responsibility to oversee our risk management framework and policies. Any material non-compliance or failures in internal controls and recommendations for improvements will be reported to the Audit Committee. The Audit Committee will also review the effectiveness of the actions taken by Management on the recommendations made by the external and internal auditors. Further, the Audit Committee will update the Board on such risk management framework and policies at least annually and from time to time when necessary.

Based on the internal controls established and maintained by the Group, work performed by independent external third parties, and reviews performed by and assurance from Management, various Board Committees and the Board, the Board with the concurrence of the Audit Committee is of the opinion that the Group's system of risk management and internal controls, addressing financial, operational, compliance and information technology risks, which the Group considers relevant and material to its current business scope and environment, was adequate as at 31 December 2014. Nonetheless, it is understood that such a system can only provide reasonable, but not absolute, assurance that the Group will not be adversely affected by any event that could be reasonably foreseen as it strives to achieve its business objectives. The Board also notes that no system of internal controls and risk management can provide a complete assurance against human error, poor judgement in decision making, losses, fraud or other irregularities.

INTERNAL AUDIT

KPMG LLP has been appointed to act as the Group's internal audit function ("Internal Auditors"). It is responsible for executing the Internal Audit Plan as approved by the Audit Committee and reporting the findings and recommendations of such audit to the Audit Committee on a quarterly basis. The Internal Auditors' primary line of reporting is to the Chairman of the Audit Committee, although the function reports administratively to the executive Directors. All internal audit summary reports are submitted to the Audit Committee for consideration, with copies of these reports extended to the Chairman, executive Directors (specifically the CEO) and the relevant Senior Management. To ensure timely and adequate closure

of internal audit findings, the status of the implementation of the actions agreed by Management is tracked by and will be discussed with the Audit Committee.

Staffed by qualified executives, the Internal Auditors have unrestricted direct access to the Audit Committee and unfettered access to all documents, records, properties and personnel. The functions of the external Auditors are carried out according to the International Professional Practices Framework developed by the Institute of Internal Auditors.

The Audit Committee approves the hiring, removal, evaluation and compensation of the auditing firm to which the internal audit function is outsourced. The Audit Committee is also responsible for the review, at least annually, of the adequacy and effectiveness of the internal audit function.

PRINCIPLE 14 SHAREHOLDER RIGHTS & RESPONSIBILITIES

We believe in having a robust governance culture to ensure that our shareholders are awarded fair and equitable treatment. We recognise that shareholders should be entitled to equal information rights and we strive to provide adequate, timely and sufficient information pertaining to changes and updates in our business, which could have a material impact on the share price and value of the Company.

Shareholders whose names are registered in the Register of the Central Depository Pte Ltd and the Register of Members are entitled to participate in, and vote at, shareholders' meetings. Shareholders are informed of shareholders' meetings through notices published in newspapers and reports or circulars sent to all shareholders. All shareholders have the opportunity to participate effectively in and vote at shareholders' meetings and will be informed of the rules, including voting procedures, which govern such shareholders' meetings. If any shareholder is unable to attend, he is allowed to appoint up to two proxies to vote on his behalf at the meeting through proxy forms sent in advance. At shareholders' meetings, each distinct issue is proposed as a separate resolution and the results of the votes are announced at the shareholders' meetings.

We advocate shareholder participation and will hold our shareholders' meetings in a central location in Singapore. Shareholders will be able to proactively engage the Board and Management on our business activities and financial performance.

PRINCIPLE 15 COMMUNICATION WITH SHAREHOLDERS

We believe in regular, effective and fair communication with our shareholders and we are committed to hearing shareholders' views and addressing their concerns where possible. To facilitate that, we have a dedicated investor relations team tasked with the responsibility of organising and maintaining regular communication with our shareholders and stakeholders. We will hold semi-annual shareholders' forums to educate our shareholders, which allow our shareholders an avenue to raise any queries to Management. Briefing sessions are conducted for the media and analysts when quarterly financial results are released.

All press statements, financial results and material information are published on SGXNET and our website *www.krisenergy.com*, and where appropriate, through media releases on a timely basis. Our announcements and website provide contact details for investors and shareholders in the event they wish to reach out to us.

Throughout the financial year, Management has also participated in local and foreign investor meetings, conferences and forums, which provide an avenue for Management to explain our business strategy and financial performance. Management is provided with an opportunity to seek the investors and analysts' feedback and perceptions of the Company during these meetings, conferences and forums.

We do not have a fixed dividend policy. Taking into consideration factors including but not limited to our results of operations and cash flow, expected financial performance and working capital needs, future prospects, capital expenditures and other investment plans, other investment and growth plans, general economic and business conditions and other factors deemed relevant by the Board and statutory restrictions on the payment of dividends, we do not intend to pay dividends for the financial year in review.

PRINCIPLE 16 CONDUCT OF SHAREHOLDER MEETINGS

At each AGM, the Chairman will address the shareholders with a brief opening speech. Our external auditors will also be present to address shareholders' queries on the conduct of the audit and the preparation and content of the auditors' report. Directors, chairpersons of each Board Committee, or members of the respective Committees standing in for them, will be present at each AGM and other shareholders' meetings held by us, if any, to address shareholders' queries. We will also ensure that appropriate Management personnel will be present at each AGM and other shareholders' meetings held by us, if any, to respond to any queries from shareholders.

A Company Secretary will prepare minutes of the shareholders' meetings, which will include any substantial comments or queries from shareholders and the corresponding responses from our Board and Management. These minutes will be made available to shareholders upon request.

Each item of special business included in the notice of the shareholders' meeting will be accompanied by a full explanation of the effects of a proposed resolution. Separate resolutions are proposed for substantially separate issues at such meetings. Resolutions will be put to vote by electronic poll and detailed results showing the number of votes cast for and against each resolution and their respective percentage will be announced.

The Company is not implementing absentia voting methods such as voting via mail, email or facsimile until security, integrity and other pertinent issues are satisfactorily resolved.

SECURITIES DEALING

Securities Transactions Policy

We have adopted a company-wide Securities Transactions Policy on dealings in the securities of the Company, which emphasises the implications of insider trading and gives illustrative guidance on such dealing, including the prohibition on dealings with the Company's securities on short-term considerations or in circumstances when there is possession of material non-public information. Such policy has been disseminated to the Directors and officers. In compliance with the Listing Manual of the SGX-ST on best practices on dealing in securities, a reminder is issued to the Directors and officers notifying them that the Company, Directors and officers must not deal in listed securities of the Company one month before the release of the full year results and two weeks before the release of quarterly results. Directors and Management are expected to observe insider trading laws at all times, even when dealing in securities outside of the "black-out period" as prescribed.

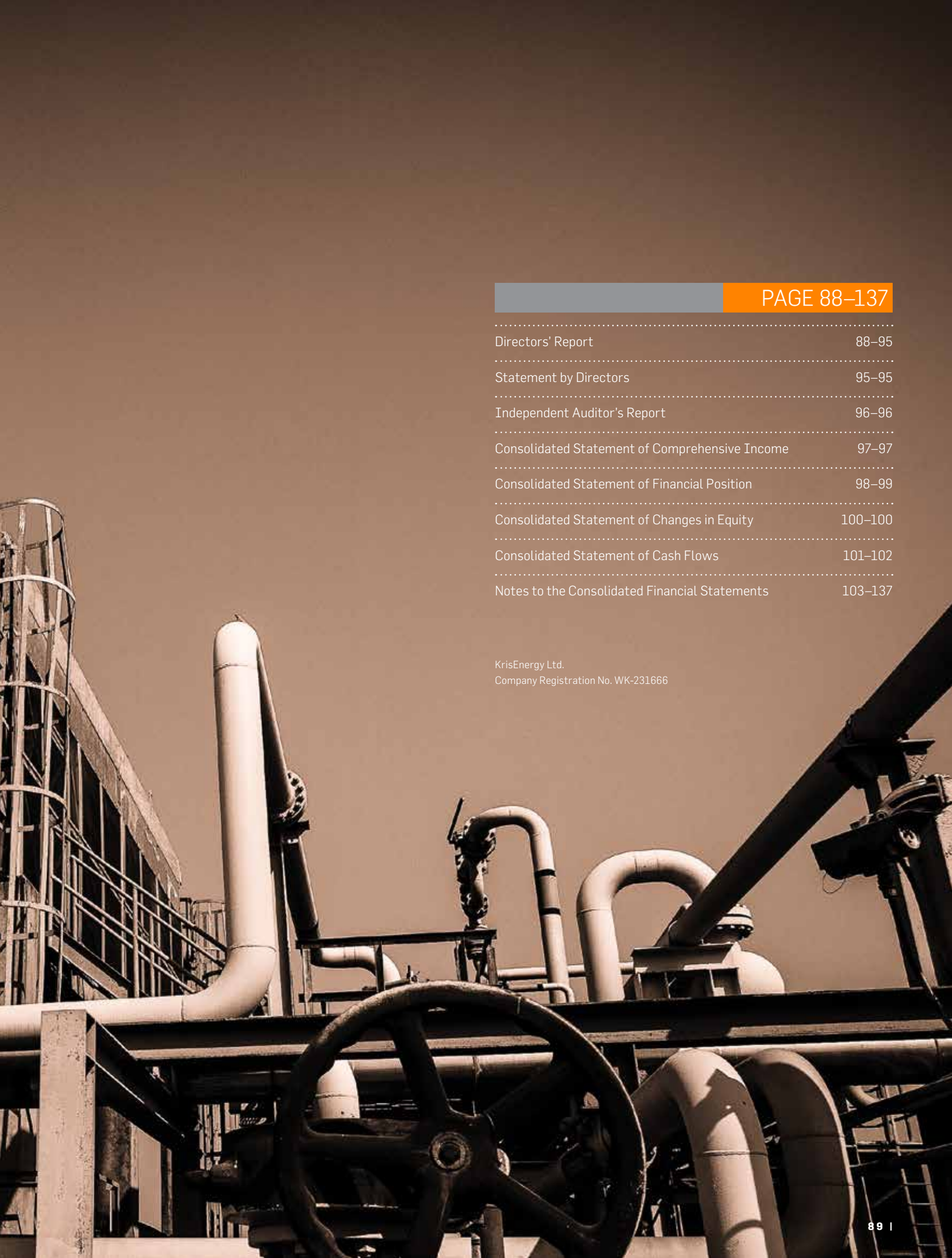
DIRECTORS' REPORT AND FINANCIAL STATEMENTS



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KrisEnergy Ltd.
Company Registration No. WK-231666



The Directors present herein their report together with the audited consolidated financial statements of the Group and balance sheet and statement of changes in equity of the Company for the financial year ended 31 December 2014.

1 DIRECTORS

The Directors in office at the date of this Directors' Report are:

WILL HONEYBOURNE
Non-Executive Chairman

JOHN KOH
Lead Non-Executive Independent Director

KEITH CAMERON
Executive Director and Chief Executive Officer

CHRIS GIBSON-ROBINSON
Executive Director

RICHARD LORENTZ
Executive Director

BROOKS SHUGHART
Non-Executive Director

CHOO CHIAU BENG
Non-Executive Director

LOH CHIN HUA
Non-Executive Director

DUANE RADTKE
Non-Executive Independent Director

JEFF MACDONALD
Non-Executive Independent Director

TAN EK KIA
Non-Executive Independent Director

ALAN NISBET
Non-Executive Independent Director

KEITH PRINGLE
Non-Executive Independent Director

2 AUDIT COMMITTEE

The Audit Committee comprises four independent Directors. Members of the Audit Committee are:

JOHN KOH
Chairman

TAN EK KIA

CHOO CHIAU BENG

BROOKS SHUGHART

ALAN NISBET

KEITH PRINGLE

The Audit Committee carried out its function in accordance with the Code of Corporate Governance 2012, including the following:

- reviewing all financial information and any public financial reporting with Management and external auditors for submission to the Board;
- reviewing significant financial reporting issues and judgements so as to ensure the integrity of the financial statements of the Company and any announcements relating to the Company's financial performance;
- reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from Management on difficulties which they have encountered with Management in the course of their audit;
- reviewing with external and internal auditors and reporting to the Board at least annually the adequacy and effectiveness of the internal control system, including financial, operational, compliance and information technology controls (such review can be carried out internally or with the assistance of any competent third parties);
- reviewing with internal auditors, the program, scope and results of the internal audit and Management's response to their findings to ensure that appropriate follow-up measures are taken;
- reviewing at least annually, the adequacy and effectiveness of the internal audit function;
- reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
- reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- reviewing interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interests have been put in place;
- assessing the suitability of an accounting firm as external auditors and recommending to the Board the appointment or re-appointment of such external auditors approving their compensation and reviewing and approving their discharge;
- reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure;
- commissioning and reviewing the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material;
- reviewing risk management policies and guidelines and monitoring compliance therewith;
- reviewing and approving all hedging policies and types of hedging instruments;
- reviewing whistle-blowing policies and arrangements;
- reporting to the Board the work performed by the Audit Committee in carrying out functions;
- monitoring the investments in customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management of or have shareholding interests in similar or related business of the Company and making assessments on whether there are any potential conflicts of interests; and
- undertaking generally such other functions and duties as may be required by the Listing Manual of the SGX-ST and by amendments made thereto.

The Audit Committee has recommended to the Board of Directors the nomination of Ernst & Young LLP for re-appointment as external auditors at the forthcoming Annual General Meeting of the Company.

3 ARRANGEMENTS TO ENABLE TO ACQUIRE SHARES AND DEBENTURES

Neither at the end of the financial year nor at any time during the financial year did there subsist any arrangement whose object is to enable the Directors of the Company to acquire benefits by means of the acquisition of shares or debentures in the Company or any other body corporate other than the performance shares granted under the KrisEnergy PSP.

4 DIRECTORS' INTEREST IN SHARES AND DEBENTURES

The interests of Directors holding office at the beginning and end of the financial year in the share capital of the Company or its related corporations according to the Register of Directors' Shareholdings kept by the Company were as follows:

	HOLDINGS REGISTERED IN NAME OF DIRECTORS OR NOMINEES		HOLDINGS IN WHICH DIRECTORS ARE DEEMED TO HAVE AN INTEREST	
NAME OF DIRECTOR	AS AT 31 DECEMBER 2014	AS AT 1 JANUARY 2014 OR DATE OF APPOINTMENT, IF LATER	AS AT 31 DECEMBER 2014	AS AT 1 JANUARY 2014 OR DATE OF APPOINTMENT, IF LATER
Will Honeybourne	–	–	–	–
John Koh	100,000 [1]	100,000	–	–
Keith Cameron	–	100,000	The aggregate of[2]: (i) 4,415,285 Shares; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii) 1,095,627 PSP Awards	The aggregate of: (i) 4,208,216 Shares; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii) 321,208 PSP Awards
Chris Gibson-Robinson	221,069	114,000	The aggregate of[3]: (i) 4,208,216 Shares; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii) 1,095,627 PSP Awards	The aggregate of: (i) 4,208,216; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii) 321,208 PSP Awards
Richard Lorentz	207,069	100,000	The aggregate of[4]: (i) 4,208,216 Shares; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii) 1,095,627 PSP Awards	The aggregate of: (i) 4,208,216 Shares; (ii) up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (iii)321,208 PSP Awards
Brooks Shughart	–	–	–	–
Choo Chiau Beng	–	–	–	–
Loh Chin Hua	–	–	–	–
Duane Radtke	–	–	1,615,008[5]	1,615,008
Jeff MacDonald	352,536[6]	352,536	–	–
Tan Ek Kia	100,000	100,000	–	–
Alan Nisbet	–	–	–	–
Keith Pringle	171,344[6]	171,344	–	–

5 DIRECTORS' RECEIPT & ENTITLEMENT TO CONTRACTUAL BENEFITS

Since the end of the previous financial year, no Director has received or become entitled to receive a benefit by reason of a contract made by the Company or a related corporation with the Director or with a firm of which he is a member, or with a company in which he has a substantial financial interest, except as disclosed in the accompanying financial statements and in this Annual Report.

6 DIRECTORS' RECEIPT & ENTITLEMENT TO CONTRACTUAL BENEFITS

The Remuneration Committee is responsible for administering the KrisEnergy ESOS and the KrisEnergy PSP. As at the date of this Directors' Report, the members of the Remuneration Committee are as follows:

Jeff MacDonald
Chairman

Duane Radtke

Brooks Shughart

Loh Chin Hua

Alan Nisbet

Keith Pringle

The KrisEnergy ESOS and KrisEnergy PSP were adopted on 10 July 2013, in conjunction with the initial public offering of the Company. The duration of these share-based incentive schemes is 10 years commencing from 10 July 2013.

The KrisEnergy ESOS and KrisEnergy PSP were established with the objective of rewarding, motiving and retaining our employees and Directors to achieve better performance. Through these share-based incentive schemes, we will be able to recognise and reward past contributions and services and motivate eligible employees and Directors to continue to strive for our long-term success.

Restrictions: The aggregate number of Shares which may be issued pursuant to the options and/or awards granted under the KrisEnergy ESOS and/or the KrisEnergy PSP, when added to the number of Shares issued and/or issuable in respect of all options and awards granted under the KrisEnergy ESOS and KrisEnergy PSP, shall not exceed 15% of the total issued share capital of the Company on the day immediately preceding the date of the relevant grant.

Unless otherwise decided by the Remuneration Committee, the entitlement to any share options or share awards is conditional on the continued employment of the eligible employee or Director up to the specified vesting date.

NOTES:

(1) Held through nominee, DBS Nominees Pte Ltd

(2) Keith Cameron's deemed interests as at 31 December 2014 comprised:
  (a) 207,069 Shares held in trust by Flamboyant Ltd for his benefit and 4,208,216 Shares held by CKR Resources (B.V.I.) Ltd ("CKR Resources"), of which he is a controlling shareholder;
  (b) Shares awarded to him under the KrisEnergy PSP (MS-Awards) on 19 July 2013 ("Listing Date") comprising up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions; and
  (c) up to 1,095,627 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, 25 June 2014 and 31 December 2014 subject to certain performance conditions being met and other terms and conditions

(3) Chris Gibson-Robinson's deemed interests as at 31 December 2014 comprised:
  (a) 4,208,216 Shares held by CKR Resources, of which he is a controlling shareholder;
  (b) Shares awarded to him under the KrisEnergy PSP (MS-Awards) on the Listing Date comprising up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions; and
  (c) up to 1,095,627 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, 25 June 2014 and 31 December 2014 subject to certain performance conditions being met and other terms and conditions

(4) Richard Lorentz's deemed interests as at 31 December 2014 comprised:
  (a) 4,208,216 Shares held by CKR Resources, of which he is a controlling shareholder;
  (b) Shares awarded to him under the KrisEnergy PSP (MS-Awards) on the Listing Date comprising up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions; and
  (c) up to 1,095,627 Shares awarded to him under the KrisEnergy PSP on 13 November 2013, 25 June 2014 and 31 December 2014 subject to certain performance conditions being met and other terms and conditions

(5) Duane Radtke is deemed interested in the 1,615,008 Shares held by Radtke Investments L.P ("RILP") as Duane Radtke and his wife are the general partners of RILP and each is able to make investment decisions for RILP. RILP is owned by Duane Radtke (2.0%) and his wife (2.0%) and their two sons (48.0% each)

(6) Held through nominee, Raffles Nominees Pte Ltd

According to the Register of Directors' Shareholdings kept by the Company, there were no changes to any of the above-mentioned interests between the end of the financial year and 21 January 2015.

Special provisions for vesting and lapsing of awards granted under the KrisEnergy ESOS and KrisEnergy PSP apply for events such as the retirement, ill health or termination of employment and any other events approved by the Remuneration Committee. Upon the occurrence of such events, the Remuneration Committee will consider, at its discretion, whether or not to release any award, and will take into account circumstances of each individual case, including but not limited to the contributions made by that employee or Director.

Eligibility: Employees who are not on probation and all Directors (including non-executive or independent Directors) of the Group who are in the employment of the Group are eligible to participate in the KrisEnergy ESOS and KrisEnergy PSP. Such an eligible participant must not be an undischarged bankrupt or have entered into a composition with his creditors.

SHARE OPTIONS

As at the date of this Directors' Report, the Company has not issued any share options pursuant to the KrisEnergy ESOS.

SHARE AWARDS

Participants of the KrisEnergy PSP will receive fully paid shares free of charge, the equivalent in cash, or combinations thereof, provided that performance targets are met within a prescribed performance period.

Since the commencement of the KrisEnergy PSP to the end of the financial year under review, PSP Awards comprising an aggregate of 10,617,537 shares have been granted to employees of the Company, including an aggregate of 3,608,088 Shares awarded to the Executive Directors of the Company. In addition, awards have been granted under the KrisEnergy PSP on the Listing Date to three executive Directors and six executive officers of the Company, subject to certain performance conditions being met and other terms and conditions (MS-Awards). The maximum number of Shares that may be issued under the MS-Awards is 3.0% of the issued share capital of the Company. Under an MS-Award, each grantee has the conditional right to receive from the Company such number of Shares (fully paid up by the Company as required by law, as to par value) as represents up to one-ninth of 3.0% of the issued ordinary share capital of the Company.

Of the PSP Awards comprising an aggregate of 10,617,537 Shares granted under the KrisEnergy PSP, PSP Awards comprising 1,809,898 Shares vested, and were allotted and issued to our employees, including 321,207 Shares to the executive Directors on 21 July 2014.

Share awards granted, vested and cancelled during the financial year, and share awards outstanding as at the end of the financial year, are reflected in the table below:

DATE OF GRANT	BALANCE AS AT 1 JANUARY 2014	SHARE AWARDS GRANTED	SHARE AWARDS VESTED	SHARE AWARDS CANCELLED	BALANCE AS AT 31 DECEMBER 2014
19 JULY 2013 (MS-AWARDS)					
DIRECTORS					
Keith Cameron	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	–	–	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
Chris Gibson-Robinson	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	–	–	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
Richard Lorentz	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	–	–	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
OTHER STAFF	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied			up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
13 NOVEMBER 2013					
DIRECTORS					
Keith Cameron	321,208	321,208	107,069	–	214,139
Chris Gibson-Robinson	321,208	321,208	107,069	–	214,139
Richard Lorentz	321,208	321,208	107,069	–	214,139
OTHER EMPLOYEES	4,466,065	4,466,065	1,488,691	–	2,977,374
25 JUNE 2014					
DIRECTORS					
Keith Cameron	–	321,208	–	–	321,208
Chris Gibson-Robinson	–	321,208	–	–	321,208
Richard Lorentz	–	321,208	–	–	321,208
OTHER EMPLOYEES	–	749,487	–	–	749,487

DATE OR GRANT	BALANCE AS AT 1 JANUARY 2014	SHARE AWARDS GRANTED	SHARE AWARDS VESTED	SHARE AWARDS CANCELLED	BALANCE AS AT 31 DECEMBER 2014
31 DECEMBER 2014					
DIRECTORS					
Keith Cameron	–	560,280	–	–	560,280
Chris Gibson-Robinson	–	560,280	–	–	560,280
Richard Lorentz	–	560,280	–	–	560,280
OTHER EMPLOYEES	–	1,793,897	–	–	1,793,897

Save as disclosed in the table above, no Shares have been awarded under the KrisEnergy PSP to:

(a) any other Director of the Company;

(b) any Controlling Shareholder or its associate;

(c) any director or employee of any parent company and its subsidiaries; or

(d) any participant who has received Shares pursuant to the vesting of awards granted under the KrisEnergy PSP which, in aggregate, represents 5.0% or more of the total number of Shares available under the KrisEnergy PSP.

7 AUDITORS

Our auditors, Ernst & Young LLP, have expressed their willingness to accept re-appointment.

On behalf of the Board of Directors

KEITH CAMERON Director	**CHRIS GIBSON-ROBINSON** Director

16 March 2015, Singapore

STATEMENT BY DIRECTORS

WE, KEITH CAMERON AND CHRISTOPHER GIBSON-ROBINSON, BEING TWO OF THE DIRECTORS OF KRISENERGY LTD. ("THE COMPANY"), DO HEREBY STATE THAT, IN THE OPINION OF THE DIRECTORS,

(i) the accompanying financial statements of the Company and its subsidiaries (collectively, the "Group"), which comprise the statement of financial position of the Group and the Company as at 31 December 2014, the statement of changes in equity of the Group and the Company and the consolidated statement of comprehensive income and consolidated statement of cash flows of the Group for the year then ended together with notes thereto are drawn up so as to give a true and fair view of the state of affairs of the Group and of the Company as at 31 December 2014 and the results of the business, changes in equity and cash flows of the Group and the changes in equity of the Company for the year ended on that date, and

(ii) at the date of this statement, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they fall due.

On behalf of the Board of Directors

KEITH GORDON CAMERON Director	**CHRIS GIBSON-ROBINSON** Director

16 March 2015

INDEPENDENT AUDITOR'S REPORT

For the financial year ended 31 December 2014

Independent auditor's report to the members of KrisEnergy Ltd.

Report on the Financial Statements

We have audited the accompanying financial statements of KrisEnergy Ltd. ("the Company") and its subsidiaries (collectively, the "Group"), which comprise the statement of financial position of the Group and the Company as at 31 December 2014, the statement of changes in equity of the Group and the Company and the consolidated statement of comprehensive income and consolidated statement of cash flows of the Group for the year 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 these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

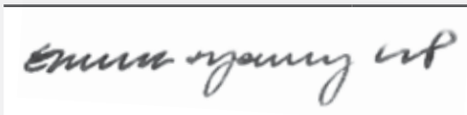
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with International Standards on Auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the 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 auditor's judgement, 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 auditor considers 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.

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 financial statements of the Group and the statement of financial position and statement of changes in equity of the Company are properly drawn up in accordance with the provisions of the International Financial Reporting Standards so as to give a true and fair view of the state of affairs of the Group and of the Company as at 31 December 2014 and the results, changes in equity and cash flows of the Group and the changes in equity of the Company for the year ended on that date.



ERNST & YOUNG LLP
Public Accountants and Chartered Accountants

16 March 2015, Singapore

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the financial year ended 31 December 2014

	NOTE	2014 US$	2013 US$
Revenue	6	**74,905,229**	**69,050,403**
Cost of sales	6	(55,236,207)	(43,586,834)
Gross profit		**19,669,022**	**25,463,569**
Other income	6	9,330,854	16,235,154
General and administrative expenses	6	(35,718,914)	(31,736,435)
Other operating (expenses)/income	6	(9,983,883)	1,631,311
Finance income	6	577,251	1,853,888
Finance costs	6	(23,153,200)	(13,333,991)
(Loss)/profit before tax	6	**(39,278,870)**	**113,496**
Tax expense	7	(11,091,626)	(12,758,629)
Loss for the year		**(50,370,496)**	**(12,645,133)**
Other comprehensive income:			
Items that may be reclassified subsequently to profit or loss			
Exchange differences on translation of foreign operations		(164,523)	(79,567)
Items that will not be reclassified to profit or loss			
Re-measurement of defined benefit obligations		(139,139)	–
Total comprehensive income attributable to owners of the Company		**(50,674,158)**	**(12,724,700)**
Loss per share attributable to owners of the Company (cents per share)			
Basic	6	(5)	(2)
Diluted	6	(5)	(2)

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 31 December 2014

		GROUP		COMPANY	
ASSETS	**NOTE**	**2014** US$	**2013** US$	**2014** US$	**2013** US$
Non-current assets					
Exploration and evaluation assets	8	402,778,672	200,261,113	–	–
Oil and gas properties	9	136,334,779	140,596,081	–	–
Other property, plant and equipment	10	1,161,203	332,225	–	–
Intangible assets	11	91,452,905	43,890,735	–	–
Embedded derivatives	12	–	6,137,226	–	–
Investment securities	13	–	182,057	–	–
Investment in subsidiaries	14	–	–	330,557,206	327,434,237
Other receivables	16	–	–	645,464,973	65,000,000
		631,727,559	**391,399,437**	**976,022,179**	**392,434,237**
Current assets					
Inventories	15	14,670,074	7,027,163	–	–
Trade and other receivables	16	65,165,491	54,149,712	–	122,982
Prepayments		1,545,274	2,762,318	126,755	237,146
Cash and bank balances	17	51,334,088	251,809,697	1,610,557	211,400,012
		132,714,927	315,748,890	1,737,312	211,760,140
Assets held for sale	18	64,986,883	–	–	–
		197,701,810	**315,748,890**	**1,737,312**	**211,760,140**
Total assets		**829,429,369**	**707,148,327**	**977,759,491**	**604,194,377**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements

EQUITY AND LIABILITIES	NOTE	GROUP 2014 US$	GROUP 2013 US$	COMPANY 2014 US$	COMPANY 2013 US$
Equity					
Share capital	19	1,309,955	1,307,693	1,309,955	1,307,693
Share premium	19	604,582,768	602,938,278	604,582,768	602,938,278
Foreign currency translation reserve	19	(1,464,175)	(1,299,652)	–	–
Employee share option reserve	19	1,689,441	527,847	1,689,441	527,847
Accumulated losses		(187,150,996)	(136,641,361)	(19,760,492)	(1,481,415)
Total equity		**418,966,993**	**466,832,805**	**587,821,672**	**603,292,403**
Non-current liabilities					
Employee benefit liability	23	1,483,647	884,691	–	–
Loans and borrowings	21	257,440,512	–	247,440,512	–
Deferred tax liabilities	7	40,309,640	41,909,685	–	–
Provisions	22	38,602,143	23,741,232	–	–
Other payables	20	–	–	119,062,800	281,741
		337,835,942	**66,535,608**	**366,503,312**	**281,741**
Current liabilities					
Trade and other payables	20	27,393,025	35,990,001	3,770,137	26,130
Accrued operating expenses	20	20,191,470	13,012,320	275,728	594,103
Loans and borrowings	21	–	119,141,003	–	–
Derivative liabilities	25	19,388,642	–	19,388,642	–
Withholding tax payable		561,305	56,880	–	–
Tax payable		5,091,992	5,579,710	–	–
		72,626,434	**173,779,914**	**23,434,507**	**620,233**
Total liabilities		**410,462,376**	**240,315,522**	**389,937,819**	**901,974**
Total equity and liabilities		**829,429,369**	**707,148,327**	**977,759,491**	**604,194,377**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the financial year ended 31 December 2014

GROUP	SHARE CAPITAL	SHARE PREMIUM	ACCUMULATED LOSSES	FOREIGN CURRENCY TRANSLATION RESERVE	EMPLOYEE SHARE OPTION RESERVE	TOTAL EQUITY
	US$	US$	US$	US$	US$	US$
Balance at 1 January 2014	**1,307,693**	**602,938,278**	**(136,641,361)**	**(1,299,652)**	**527,847**	**466,832,805**
Loss net of tax	–	–	(50,370,496)	–	–	(50,370,496)
Other comprehensive income						
Exchange differences on translation of foreign operations	–	–	–	(164,523)	–	(164,523)
Re-measurement of defined benefit obligations	–	–	(139,139)	–	–	(139,139)
Total comprehensive income for the year	–	–	(50,509,635)	(164,523)	–	(50,674,158)
Grant of equity-settled share options to employees	–	–	–	–	1,161,594	1,161,594
Vesting of equity-settled share options to employees	2,262	1,644,490	–	–	–	1,646,752
Balance at 31 December 2014	**1,309,955**	**604,582,768**	**(187,150,996)**	**(1,464,175)**	**1,689,441**	**418,966,993**
Balance at 1 January 2013	**1,000,000**	**402,750,000**	**(123,996,228)**	**(1,220,085)**	**–**	**278,533,687**
Loss net of tax	–	–	(12,645,133)	–	–	(12,645,133)
Other comprehensive income						
Exchange differences on translation of foreign operations	–	–	–	(79,567)	–	(79,567)
Total comprehensive income for the year	–	–	(12,645,133)	(79,567)	–	(12,724,700)
Grant of equity-settled share options to employees	–	–	–	–	527,847	527,847
Issue of shares	307,693	212,678,368	–	–	–	212,986,061
Share issuance expense	–	(12,490,090)	–	–	–	(12,490,090)
Balance at 31 December 2013	**1,307,693**	**602,938,278**	**(136,641,361)**	**(1,299,652)**	**527,847**	**466,832,805**

COMPANY	SHARE CAPITAL	SHARE PREMIUM	ACCUMULATED LOSSES	EMPLOYEE SHARE OPTION RESERVE	TOTAL EQUITY
	US$	US$	US$	US$	US$
Balance at 1 January 2014	**1,307,693**	**602,938,278**	**(1,481,415)**	**527,847**	**603,292,403**
Loss net of tax	–	–	(18,279,077)	–	(18,279,077)
Other comprehensive income	–	–	–	–	–
Total comprehensive income for the year	–	–	(18,279,077)	–	(18,279,077)
Grant of equity-settled share options to employees	–	–	–	1,161,594	1,161,594
Vesting of equity-settled share options to employees	2,262	1,644,490	–	–	1,646,752
Balance at 31 December 2014	**1,309,955**	**604,582,768**	**(19,760,492)**	**1,689,441**	**587,821,672**
Balance at 1 January 2013	1,000,000	402,750,000	(1,965,586)	–	401,784,414
Profit net of tax	–	–	484,171	–	484,171
Other comprehensive income	–	–	–	–	–
Total comprehensive income for the year	–	–	484,171	–	484,171
Grant of equity-settled share options to employees	–	–	–	527,847	527,847
Issue of shares	307,693	212,678,368	–	–	212,986,061
Share issuance expense	–	(12,490,090)	–	–	(12,490,090)
Balance at 31 December 2013	**1,307,693**	**602,938,278**	**(1,481,415)**	**527,847**	**603,292,403**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the financial year ended 31 December 2014

OPERATING ACTIVITIES	NOTE	2014 US$	2013 US$
(Loss)/profit before tax		**(39,278,870)**	**113,496**
Adjustment to reconcile (loss)/profit before tax to net cash flows:			
Depreciation, depletion and amortisation		29,141,379	20,404,684
Decommissioning provisions	22	14,218,838	1,284,797
Grant of equity-settled share options to employees	24	2,808,346	527,847
Excess of fair value of identifiable net assets acquired over consideration paid	4	–	(12,936,286)
Loss on disposal of other property, plant and equipment		12,508	–
Loss on disposal of investment securities	13	182,057	–
Net fair value loss/(gain) on embedded derivatives		6,137,226	(2,284,698)
Net fair value loss on hedge	25	2,960,446	–
Employee defined benefit		226,224	884,691
Finance cost		22,511,127	12,902,199
Unwinding of discount on decommissioning provisions	22	642,073	431,792
Write-back of unused decommissioning provisions	22	–	(667,226)
Interest income		(577,251)	(1,853,888)
Operating cash flows before changes in working capital		38,984,103	18,807,408
Changes in working capital			
Increase in inventories		(7,504,782)	(883,084)
Increase in trade and other receivables		(4,713,161)	(6,458,170)
Decrease in other current assets		–	500,000
(Decrease)/increase in trade and other payables		(278,270)	23,011,716
Cash flows from operations		**26,487,890**	**34,977,870**
Interest received		577,251	1,853,888
Interest paid		(7,566,799)	(1,568,367)
Taxes paid		(13,179,388)	(19,019,114)
Net cash flows from operating activities		**6,318,954**	**16,244,277**

CONSOLIDATED STATEMENT OF CASH FLOWS

For the financial year ended 31 December 2014

	NOTE	2014 US$	2013 US$
INVESTING ACTIVITIES			
Additions to exploration and evaluation assets	8	(82,553,592)	(64,607,295)
Additions to oil and gas properties	9	(24,453,401)	(13,794,344)
Advances for acquisition	16	(4,152,697)	–
Expenditure on decommissioning provisions	22	–	(1,832,774)
Expenditure on assets refurbishment		(8,986,883)	–
Proceeds from disposal of other plant and equipment		7,486	–
Purchase of other plant and equipment		(57,271,702)	(427,875)
Acquisition of subsidiaries, net of cash acquired	4	(167,216,439)	(41,396,066)
Net cash flows used in investing activities		**(344,627,228)**	**(122,058,354)**
FINANCING ACTIVITIES			
Proceeds from issuance of shares	19	–	212,986,061
Proceeds from issuance of bonds	21	263,868,708	36,750,000
Proceeds from bank borrowings		135,000,000	–
Share issuance expense	19	–	(12,490,090)
Repayment of bonds		(126,300,000)	–
Repayment of bank borrowings		(125,000,000)	–
Payment of bond interest		(9,567,573)	(9,445,625)
Decrease in short-term deposits	17	4,000,000	4,000,000
Increase in cash collateralised	17	(3,758,824)	–
Net cash flows from financing activities		**138,242,311**	**231,800,346**
Net (decrease)/increase in cash and cash equivalents		**(200,065,963)**	**125,986,269**
Net effect of exchange rate changes		(168,470)	(77,526)
Cash and cash equivalents at 1 January		247,809,697	121,900,954
Cash and cash equivalents at 31 December	17	**47,575,264**	**247,809,697**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the financial year ended 31 December 2014

1 CORPORATE INFORMATION

KrisEnergy Ltd. (the "Company") was incorporated on 5 October 2009 as a limited liability company in Cayman Islands.

The registered office of the Company is located at 190 Elgin Avenue, George Town, Grand Cayman KY1-9005, Cayman Islands.

The principal activity of the Company is that of investment holding. The principal activities of the subsidiaries and joint arrangements are disclosed in Note 14 to the consolidated financial statements.

2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

2.1 BASIS OF PREPARATION

The consolidated financial statements of the Company and its subsidiaries, (collectively the "Group") have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements have been prepared on the historical cost basis except as disclosed in the accounting policies below.

The financial statements are presented in United States Dollars ("USD" or "US$"), except when otherwise indicated.

2.2 BASIS OF CONSOLIDATION

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as at 31 December 2014. The financial statements of the subsidiaries used in the preparation of the consolidated financial statements are prepared for the same reporting date as the Company. Consistent accounting policies are applied to like transactions and events in similar circumstances.

All intra-group balances, income and expenses and unrealised gains and losses resulting from intra-group transactions and dividends are eliminated in full.

Subsidiaries are consolidated from the date of acquisition, being the date on which the Group obtains control, and continue to be consolidated until the date when such control ceases.

Losses within a subsidiary are attributed to the non-controlling interest even if that results in a deficit balance.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- De-recognises the assets (including goodwill) and liabilities of the subsidiary at their carrying amounts as at the date when control is lost;
- De-recognises the carrying amount of any non-controlling interest;
- De-recognises the cumulative translation differences recognised in equity;
- Recognises the fair value of the consideration received;
- Recognises the fair value of any investment retained;
- Recognises any surplus or deficit in profit or loss;
- Re-classifies the Group's share of components previously recognised in other comprehensive income to profit or loss or retained earnings, as appropriate.

2.3 CHANGES IN ACCOUNTING POLICY AND DISCLOSURES

Changes in accounting policies

The accounting policies adopted are consistent with those of the previous financial year except in the current financial year, the Group has adopted all the new and revised standards which are effective for annual financial periods beginning on or after 1 January 2014. The adoption of these standards did not have any effect on the financial performance or position of the Group.

2.4 STANDARDS ISSUED BUT NOT YET EFFECTIVE

The Group has not adopted the following standards and interpretations that have been issued but not yet effective:

DESCRIPTION	EFFECTIVE FOR ANNUAL PERIODS BEGINNING ON OR AFTER
Amendments to IAS 19 *Defined Benefit Plans: Employee Contributions*	1 July 2014
IFRS 14 *Regulatory Deferral Accounts*	1 January 2016
Amendments to IFRS 10 *Consolidated Financial Statements*, IFRS 12 *Disclosure of Interests in Other Entities and* IAS 28 *Investments in Associates and Joint Ventures*	1 January 2016
Amendments to IFRS 11 *Joint Arrangement*	1 January 2016
Amendments to IAS 1 *Presentation of Financial Statements*	1 January 2016
Amendments to IFRS 10 *Consolidated Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*	1 January 2016
Amendments to IAS 16 *Property, Plant and Equipment* and IAS 38 *Intangible Assets*	1 January 2016
Amendments to IAS 27 *Separate Financial Statements*	1 January 2016
IFRS 15 *Revenue from Contracts with Customers*	1 January 2017
IFRS 9 *Financial Instruments*	1 January 2018

The directors expect that the adoption of the standards above will have no material impact on the financial statements in the period of initial application, except for IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers* as indicated below.

IFRS 9 Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* which reflects all phases of the financial instruments project and replaces IAS 39 *Financial Instruments: Recognition and Measurement*. The standard introduces new requirements for classification and measurement, impairment, and hedge accounting. IFRS 9 is effective for annual periods beginning on or after 1 January 2018, with early application permitted. Retrospective application is required, but comparative information is not compulsory in the year of adoption. The adoption of IFRS 9 will have an effect on the classification and measurement of the Group's financial assets, but no impact on the classification and measurement of the Group's financial liabilities.

IFRS 15 Revenue from Contracts with Customers

IFRS 15 was issued in May 2014 and establishes a new five-step model that will apply to revenue arising from contracts with customers. Under IFRS 15 revenue is recognised at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer. The principles in IFRS 15, provide a more structured approach to measuring and recognising revenue. The new revenue standard is applicable to all entities and will supersede all current revenue recognition requirements under IFRS. Either a full or modified retrospective application is required for annual periods beginning on or after 1 January 2017 with early adoption permitted. The Group is currently assessing the impact of IFRS 15 and plans to adopt the new standard on the required effective date.

2.5 BUSINESS COMBINATION AND GOODWILL

Business combinations are accounted for by applying the acquisition method. Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Acquisition-related costs are recognised as expenses in the periods in which the costs are incurred and the services are received.

Any contingent consideration to be transferred by the acquirer will be recognised 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 recognised in profit or loss.

The Group elects for each individual business combination, whether non-controlling interest in the acquiree (if any), that are present ownership interests and entitle their holders to a proportionate share of net assets in the event of liquidation, is recognised on the acquisition date at fair value, or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. Other components of non-controlling interests are measured at their acquisition date fair value, unless another measurement basis is required by another IFRS.

Any excess of the sum of the fair value of the consideration transferred in the business combination, the amount of non-controlling interest in the acquiree (if any), and the fair value of the Group's previously held equity interest in the acquiree (if any), over the net fair value of the acquiree's identifiable assets and liabilities is recorded as goodwill. The accounting policy for goodwill is set out in Note 2.10. In instances where the latter amount exceeds the former, the excess is recognised as excess of fair value of net assets acquired over consideration paid in profit or loss on the acquisition date.

Goodwill is initially measured at cost. Following 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, from the acquisition date, allocated to the Group's cash generating units ("CGUs") that are expected to benefit from the synergies of the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

The CGUs to which goodwill has been allocated is tested for impairment annually and whenever there is an indication that the CGU may be impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU (or group of CGUs) to which the goodwill relates.

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 fair values of the operations disposed of and the portion of the CGU retained.

2.6 JOINT ARRANGEMENTS

A joint arrangement is a contractual arrangement whereby two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint arrangement is classified either as joint operation or joint venture, based on the rights and obligations of the parties to the arrangement.

To the extent the joint arrangement provides the Group with rights to the assets and obligations for the liabilities relating to the arrangement, the arrangement is a joint operation. To the extent the joint arrangement provides the Group with rights to the net assets of the arrangement, the arrangement is a joint venture.

The Group reassesses whether the type of joint arrangement in which it is involved has changed when facts and circumstances change.

Joint operations

The Group recognises in relation to its interest in a joint operation:

- its assets, including its share of any assets held jointly;
- its liabilities, including its share of any liabilities incurred jointly;
- its revenue from the sale of its share of the output arising from the joint operation;
- its share of the revenue from the sale of the output by the joint operation; and
- its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenues and expenses relating to its interest in a joint operation in accordance with the accounting policies applicable to the particular assets, liabilities, revenues and expenses.

When the Group enters into a transaction involving a sale or contribution of assets with a joint operation in which it is a joint operator, the Group recognises gains and losses resulting from such a transaction only to the extent of the interests held by the other parties of the joint operation.

When the Group enters into a transaction involving the purchase of assets with a joint operation in which it is a joint operator, the Group does not recognise its share of the gains and losses until it resells those assets to a third party. When such transactions provide evidence of a reduction in the net realisable value of the assets to be purchased or of an impairment loss of those assets, the Group recognises its share of those losses.

2.7 FOREIGN CURRENCY

The financial statements are presented in USD, which is also the Company's functional currency. Each entity in the Group determines its own functional currency and items included in the financial statements of each entity are measured using that functional currency.

(i) Transactions and balances

Transactions in foreign currencies are measured in the respective functional currencies of the Company and its subsidiaries and are recorded on initial recognition in the functional currencies at exchange rates approximating those ruling at the transaction dates. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rates as at the dates of the initial transactions. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was measured.

Exchange differences arising on the settlement of monetary items or on translating monetary items at the end of the reporting period are recognised in profit or loss.

(ii) Consolidated financial statements

For consolidation purpose, the assets and liabilities of foreign operations are translated into USD at the rate of exchange ruling at the end of the reporting period and their profit or loss are translated at the exchange rates prevailing at the date of the

transactions. The exchange differences arising on the translation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

In the case of a partial disposal without loss of control of a subsidiary that includes a foreign operation, the proportionate share of the cumulative amount of the exchange differences are re-attributed to non-controlling interest and are not recognised in profit or loss.

2.8 OIL AND NATURAL GAS EXPLORATION, EVALUATION AND DEVELOPMENT EXPENDITURE

Oil and natural gas exploration, evaluation and development expenditure is accounted for using the successful efforts method of accounting.

Pre-licence costs

Pre-licence costs are expensed in the period in which they are incurred.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalised as intangible assets.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing.

If no future activity is planned or the licence has been relinquished or has expired, the carrying value of the licence and property acquisition costs is written off through profit or loss. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties.

Exploration and evaluation costs

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource.

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalised as exploration and evaluation intangible assets until the drilling of the well is completed and the results have been evaluated. These costs include directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors.

If no potentially commercial hydrocarbons are discovered in the field, the exploration asset is written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be carried as an intangible asset while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as an intangible asset.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through profit or loss.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Farm-outs – in the exploration and evaluation phase

The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Development costs

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development on delineation wells, is capitalised within exploration and evaluation assets.

2.9 OIL AND GAS PROPERTIES AND OTHER PROPERTY, PLANT AND EQUIPMENT

Initial recognition

Oil and gas properties and other property, plant and equipment are initially recorded at cost. Subsequent to recognition, property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets (where relevant), borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalised value of a finance lease is also included within property, plant and equipment.

When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or expensed, except for costs which qualify for capitalisation relating to oil and gas property asset additions, improvements or new developments.

Depreciation, depletion and amortisation

Oil and gas properties are depreciated, depleted and amortised on a unit-of-production basis over the total proved developed and undeveloped reserves of the field concerned. Rights and concessions are depleted on the unit-of-production basis over the total proved developed and undeveloped reserves of the relevant area. The unit-of-production rate calculation for the depreciation, depletion and amortisation of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure.

Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives which are as follows:

Renovation	3 years
Furniture and fittings	3 years
Office equipment	3 years
Computers	2 years

An item of property, plant and equipment and any significant part initially recognised is de-recognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on de-recognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in profit or loss when the asset is de-recognised.

The asset's residual values, useful lives and methods of depreciation, depletion and amortisation are reviewed at each reporting period, and adjusted prospectively, if appropriate.

Farm-outs – outside the exploration and evaluation phase

In accounting for a farm-out arrangement outside the exploration and evaluation phase, the Group:

- De-recognises the proportion of the asset that it has sold to the farmee;
- Recognises the consideration received or receivable from the farmee, which represents the cash received and/or the farmee's obligation to fund the capital expenditure in relation to the interest retained by the farmor;
- Recognises a gain or loss on the transaction for the difference between the net disposal proceeds and the carrying amount of the asset disposed of. A gain is only recognised when the value of the consideration can be determined reliably. If not, then the Group accounts for the consideration received as a reduction in the carrying amount of the underlying assets; and
- Tests the retained interests for impairment if the terms of the arrangement indicate that the retained interest may be impaired.

The consideration receivable on disposal of an item of property, plant and equipment or an intangible asset is recognised initially at its fair value by the Group. However, if payment for the item is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue. Any part of the consideration that is receivable in the form of cash is treated as a definition of a financial asset and is accounted for at amortised cost.

Major maintenance, inspection and repairs

Expenditure on major maintenance re-fits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset, that was separately depreciated and is now written off, is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised. When part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s), which is immediately written off. Inspection costs associated with major maintenance programs are capitalised and amortised over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

2.10 INTANGIBLE ASSETS

Intangible assets acquired separately are measured initially at cost. Following initial acquisition, intangible assets are carried at cost less any accumulated amortisation and any accumulated impairment losses. Internally generated intangible assets, excluding capitalised development costs, are not capitalised and expenditure is reflected in profit or loss in the year in which the expenditure is incurred.

The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite useful lives are amortised over the estimated useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortisation period and the amortisation method are reviewed at least at each financial year-end. Changes in the expected useful life or the expected pattern of consumption of future economic benefits embodied in the asset is accounted for by changing the amortisation period or method, as appropriate, and are treated as changes in accounting estimates.

Intangible assets with indefinite useful lives or not yet available for use are tested for impairment annually, or more frequently if the events and circumstances indicate that the carrying value may be impaired either individually or at the CGU level. Such intangible assets are not amortised. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the useful life assessment continues to be supportable. If not, the change in useful life from indefinite to finite is made on a prospective basis.

Gains or losses arising from de-recognition of an intangible asset are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognised in profit or loss when the asset is de-recognised.

2.11 IMPAIRMENT OF NON-FINANCIAL ASSETS

The Group assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when an annual impairment testing for an asset is required, the Group makes an estimate of the asset's recoverable amount.

An asset's recoverable amount is the higher of an asset's or CGU's fair value less costs of disposal and its value in use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount.

Impairment losses of continuing operations are recognised in profit or loss, except for assets that are previously revalued where the revaluation was taken to other comprehensive income. In this case, the impairment is also recognised in other comprehensive income up to the amount of any previous revaluation.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increase cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised previously. Such reversal is recognised in profit or loss unless the asset is measured at a revalued amount, in which case the reversal is treated as a revaluation increase.

2.12 FINANCIAL INSTRUMENTS

2.12.1 FINANCIAL ASSETS

Initial recognition and measurement

Financial assets are recognised when, and only when, the Group becomes a party to the contractual provisions of the financial instrument. The Group determines the classification of its financial assets at initial recognition.

When financial assets are recognised initially, they are measured at fair value, plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

Subsequent measurement

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

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. This category includes derivative financial instruments entered into by the Group. Derivatives, including separated embedded derivatives are also classified as held for trading.

Subsequent to initial recognition, financial assets at fair value through profit or loss are measured at fair value. Any gains or losses arising from changes in fair value of the financial assets are recognised in profit or loss. Net gains or net losses on financial assets at fair value through profit or loss include exchange differences, interest and dividend income.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not measured at fair value with changes in fair value recognised in profit or loss. These embedded derivatives are measured at fair value with changes in fair value recognised in profit or loss. Reassessment only occurs if there is a change in the terms

of the contract that significantly modifies the cash flows that would otherwise be required.

Loans and receivables

Non-derivative financial assets with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables. Subsequent to initial recognition, loans and receivables are measured at amortised cost using the effective interest method, less impairment. Gains and losses are recognised in profit or loss when the loans and receivables are de-recognised or impaired, and through the amortisation process.

De-recognition

A financial asset (or, where applicable a part of a financial asset or part of a group of similar financial assets) is de-recognised when:

- The Group transfers the contractual rights to receive the cash flows of the financial asset; or
- The Group retains the contractual rights to receive the cash flows of the financial asset, but assumes a contractual obligation to pay the cash flows to one or more recipients in a "past-through" arrangement; or
- The Group has transferred its rights to receive cash flows from the asset and either has transferred substantially all the risks and rewards of the asset, or has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

Where the Group has transferred its rights to receive cash flows from an asset and has neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognised to the extent of the Group's continuing involvement in the asset. Continuing involvement that takes the form of a guarantee over the transferred asset, is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Group could be required to repay.

Where continuing involvement takes the form of a written and/or purchased option on the transferred asset, the extent of the Group's continuing involvement is the amount of the transferred asset that the group may repurchase, except that in the case of a written put option on an asset measured at fair value, the extent of the Group's continuing involvement is limited to the lower of the fair value of the transferred asset and the option exercise price.

Impairment of financial assets

The Group assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Group first assesses whether objective evidence of impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be recognised are not included in a collective assessment of impairment.

If there is objective evidence that an impairment loss on financial assets carried at amortised cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. If a loan has a variable interest rate, the discount rate for measuring any impairment loss is the current effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. The impairment loss is recognised in profit or loss.

When the asset becomes uncollectible, the carrying amount of impaired financial asset is reduced directly or if an amount was charged to the allowance account, the amounts charged to the allowance account are written off against the carrying value of the financial asset.

To determine whether there is objective evidence that an impairment loss on financial assets has been incurred, the Group considers factors such as the probability of insolvency or significant financial difficulties of the debtor and default or significant delay in payments.

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 recognised, the previously recognised impairment loss is reversed to the extent that the carrying amount of the asset does not exceed its amortised cost at the reversal date. The amount of reversal is recognised in profit or loss.

2.12.2 FINANCIAL LIABILITIES

Initial recognition and measurement

Financial liabilities are recognised when, and only when, the Group becomes a party to the contractual provisions of the financial instrument. The Group determines the classification of its financial liabilities at initial recognition.

All financial liabilities are recognised initially at fair value plus in the case of financial liabilities not at fair value through profit or loss, directly attributable transaction costs.

Subsequent measurement

After initial recognition, financial liabilities that are not carried at fair value through profit or loss are subsequently measured at amortised cost using the effective interest method. Gains and losses are recognised in profit or loss when the liabilities are de-recognised, and through the amortisation process.

Financial assets at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading. Financial liabilities are classified as held for trading if they are acquired for the purpose of selling in the near term. This category includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Subsequent to initial recognition, financial liabilities at fair value through profit or loss are measured at fair value. Any gains or losses arising from changes in fair value of the financial liabilities are recognised in profit or loss.

De-recognition

A financial liability is de-recognised when the obligation under the liability is discharged or cancelled or expires. 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 de-recognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in profit or loss.

2.13 CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash at bank and on hand and demand deposits. These also include bank overdrafts that form an integral part of the Group's cash management.

2.14 INVENTORIES

Inventories are stated at the lower of cost and net realisable value. Cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition and is accounted for on a first-in first-out basis. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and the estimated costs necessary to make the sale.

2.15 LEASES

Operating lease payments are recognised as an operating expense in profit or loss on a straight-line basis over the lease term.

2.16 PROVISIONS

General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and the amount of the obligation can be estimated reliably.

Provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate. If it is no longer probable that an outflow of economic resources will be required to settle the obligation, the provision is reversed. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. When discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

Decommissioning liability

The Group recognises a decommissioning liability when it has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made.

The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/construction of the field. Any decommissioning obligations that arise through the production of inventory are expensed when the inventory item is recognised in cost of goods sold.

Changes in the estimated timing of decommissioning or changes to the decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to oil and gas assets.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to profit or loss.

If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Group considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the estimate for the revised value of oil and gas assets net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense.

Over time, the discount liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in profit or loss as a finance cost.

The Group recognises neither the deferred tax asset in respect of the temporary difference on the decommissioning liability nor the corresponding deferred tax liability in respect of the temporary difference on a decommissioning asset.

Environmental expenditures and liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalised as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognised when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognised is the best estimate of the expenditure required. If the effect of the time value of money is material, the amount recognised is the present value of the estimated future expenditure.

2.17 HEDGE ACCOUNTING

The Group applies hedge accounting for certain hedging relationships which qualify for hedge accounting.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging the exposure to changes in the fair value of a recognised asset or liability or an unrecognised firm commitment.

At the inception of a hedging relationship, the Group formally designates and documents the hedging relationship to which the Group wishes to apply hedge accounting and the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how the entity will assess the effectiveness of changes in the hedging instrument's fair value in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. Such hedges are expected to be highly effective in achieving offsetting changes in fair value or cash flows and are assessed on an ongoing basis to determine that they actually have been highly effective throughout the financial reporting periods for which they were designated.

Hedges which meet the strict criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in the fair value of a hedging derivative is recognised in profit or loss in other operating expenses. The change in the fair value of the hedged item attributable to the risk hedged is recorded as a part of the carrying value of the hedged item and is also recognised in profit or loss in other operating expenses.

For fair value hedges relating to items carried at amortised cost, the adjustment to carrying value is amortised through profit or loss over the remaining term of the hedge using the effective interest rate method. Effective interest rate amortisation may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged. If the hedged item is de-recognised, the unamortised fair value is recognised immediately in profit or loss.

When an unrecognised firm commitment is designated as a hedged item, the subsequent cumulative change in fair value of the firm commitment attributable to the hedged risk is recognised as an asset or liability with a corresponding gain or loss recognised in profit or loss.

The Group has cross currency swaps that are used as hedges for the exposure of changes in the fair value of its KEL Multi-currency Medium Term Notes. See Note 25 for more details.

2.18 NON-CURRENT ASSETS HELD FOR SALE

Non-current assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Non-current assets are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use.

Other property, plant and equipment once classified as held for sale are not depreciated.

2.19 REVENUE RECOGNITION

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured, regardless of when the payment is made. Revenue is measured at the fair value of consideration received or receivable, taking into account contractually defined terms of payment and excluding taxes or duty.

Revenue from the sale of oil and gas is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts. Differences between oil lifted and sold and the Group's share of production are not significant. Where forward sale and purchase contracts for oil or natural gas have been determined to be for trading purposes, the associated sales and purchases are reported net.

The following criteria are also applicable to other specific revenue transactions:

Take-or-pay contracts

Under these contracts, the Group makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. These commitments contain protective (*force majeure)* and adjustment provisions. If a buyer has a right to get a 'make-up' delivery at a later date, revenue recognition is deferred and only recognised when the product is delivered, or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognised when the take-or-pay penalty is triggered.

2.20 EMPLOYEE BENEFITS

(a) Defined contribution plans

The Group makes contributions to the defined contribution pension schemes. Contributions to defined contribution pension schemes are recognised as an expense in the period in which the related service is performed.

(b) Employee leave entitlement

Employee entitlements to annual leave are recognised as a liability when they accrue to the employees. The estimated liability for leave is recognised for services rendered by employees up to the end of the reporting date.

(c) Share-based payments

Employees (including senior executives) of the Group receive remuneration in the form of share-based payments, whereby employees render services as consideration for equity instruments (equity-settled transactions), and are granted share appreciation rights, which are settled in cash (cash-settled transactions).

Equity-settled transactions

The cost of equity-settled transactions is determined by the fair value at the date when the grant is made using an appropriate valuation model.

That cost is recognised, together with a corresponding increase in employee share option reserve in equity, over the period in which the performance and/or service conditions are fulfilled in employee benefits expense. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimates of the number of equity instruments that will ultimately vest. The profit or loss expense or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period and is recognised in employee benefits expense in Note 24.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee as measured at the date of modification.

Cash-settled transactions

The cost of cash-settled transactions is measured initially at fair value at the grant date using a binomial model, further details of which are given in Note 24. This fair value is expensed over the period until the vesting date with recognition of a corresponding liability. The liability is re-measured to fair value at each reporting date up to, and including the settlement date, with changes in fair value recognised in employee benefits expense in Note 24.

(d) Defined benefit plan

The Group operates defined benefit pension plans in Indonesia and Thailand, which are governed by the local labour laws.

The net defined benefit liability or asset is the aggregate of the present value of the defined benefit obligations (derived using a discount rate based on high quality corporate bonds) at the end of the reporting period reduced by the fair value of plan assets (if any) adjusted for any effect of limiting a net defined benefit asset to the asset ceiling. If there is no deep market for high quality corporate bonds, the Group derives the discount rate based on government bonds instead. The asset ceiling is the present value of any economic benefits available in the form of refunds from the plan or reductions in future contributions to the plan.

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method.

Defined benefit costs comprise the following:

- Service cost;
- Net interest on the net defined benefit liability or asset; and
- Re-measurements of net defined benefit liability or asset.

Service costs which include current service costs, past service costs and gains or losses on non-routine settlements are recognised as expense in profit or loss. Past service costs are recognised when plan amendment or curtailment occurs.

Net interest on the net defined benefit liability or asset is the change during the period in the net defined benefit liability or asset that arises from the passage of time, which is determined by applying the discount rate based on high quality government bonds to the net defined benefit liability or asset. Net interest on the net defined benefit liability or asset is recognised as expense or income in profit or loss.

Re-measurements comprising actuarial gains and losses, return on plan assets and any change in the effect of the asset ceiling (excluding net interest on defined benefit liability) are recognised immediately in other comprehensive income in the period in which they arise. Re-measurements are recognised in retained earnings within equity and are not reclassified to profit or loss in subsequent periods.

Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the creditors of the Group, nor can they be paid directly to the Group. Fair value of plan assets is based on market price information. When no market price is available, the fair value of plan assets is estimated by discounting expected future cash flows using a discount rate that reflects both the risk associated with the plan assets and the maturity or expected disposal date of those assets (or, if they have no maturity, the expected period until the settlement of the related obligations).

The Group's right to be reimbursed of some or all of the expenditure required to settle a defined benefit obligation is recognised as a separate asset at fair value when and only when reimbursement is virtually certain.

2.21 TAXES

Current tax

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date in the countries where the Group operates and generates taxable income.

Current taxes are recognised in profit and loss except to the extent that the tax relates to items recognised outside profit or loss, either in other comprehensive income or directly in equity. Management

periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretations and establishes provisions where appropriate.

Deferred tax

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

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

- Where the deferred tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognised for all deductible temporary differences, the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences, and the carry forward of unused tax credits and unused tax losses can be utilised, except:

- Where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available, against which the temporary differences can be utilised.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilised. Unrecognised deferred tax assets are reassessed at the end of each reporting period and are recognised to the extent that it has become probable that future taxable profits will be available to allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting date.

Deferred tax relating to items recognised outside profit or loss is recognised outside profit or loss. Deferred tax items are recognised in correlation to the underlying transaction either in other comprehensive income or directly in other comprehensive income or directly in equity and deferred tax arising from a business combination is adjusted against goodwill on acquisition.

Royalties, resource rent tax and revenue-based taxes

In addition to corporate taxes, the Group's consolidated financial statements also include and recognise as taxes on income, other type of taxes on net income, which are calculated based on oil and gas production.

Royalties, resource rent taxes and revenue-based taxes are accounted for under IAS 12 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government tax authority and the amount payable is based on taxable income – rather than based on physical quantity produced or as a percentage of revenue – after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are recognised as current provisions and included in cost of sales.

Production-sharing agreements

According to the production-sharing agreement ("PSA"), the share of the profit oil to which the government is entitled in any calendar year, is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities. This portion of tax and revenue are presented net in profit or loss.

3 SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the disclosure of contingent liabilities at the end of each reporting period. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of the asset or liability affected in the future periods.

3.1 JUDGEMENTS MADE IN APPLYING ACCOUNTING POLICIES

In the process of applying the Group's accounting policies, management has made the following judgements which have the most significant effect on the amounts recognised in the consolidated financial statements:

Hydrocarbon reserve and resource estimates (Note 7, 8, 9, 10, 11 and 22)

Oil and gas properties are depreciated on a unit-of-production ("UOP") basis at a rate calculated by reference to total proved and probable developed and undeveloped reserves determined in accordance with Society of Petroleum Engineers' rules and incorporating the estimated future cost of developing those reserves. The Group estimates its commercial reserves based on information compiled by appropriately qualified external experts relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the PSA. Future development costs are estimated using assumptions as to number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs.
The current long-term Brent oil price assumption, derived based on the 12-month unweighted arithmetic average daily oil price, used in the estimation of commercial reserves is US$99.02 (2013: US$109.95). The carrying amount of oil and gas properties at 31 December 2014 is shown in Note 9.

As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of exploration and evaluation assets, oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows;

- Depreciation, depletion and amortisation charges in profit or loss may change where such charges are determined using the UOP method, or where the useful life of the related assets change;
- Provisions for decommissioning may change where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities; and
- The recognition and carrying value of deferred tax assets may change due to changes in judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

Exploration and evaluation expenditures (Note 8)

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether it is likely that future economic benefits are likely, either from future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economical viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when the new information becomes available.

Unit-of-production depreciation of oil and gas assets (Note 9)

Oil and gas properties are depreciated using the UOP method over total proved and probable developed and undeveloped hydrocarbon reserves. This results in a depreciation, depletion and amortisation charge proportional to the depletion of the anticipated remaining production from the field.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total proved and probable reserves, or future capital expenditure estimates changes. Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including:

- The effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions; or
- Unforeseen operational issues.

Any changes in estimates are accounted for prospectively. A 1% difference in the forecast production based on total proved and probable reserves from management's estimates would result in approximately 0.2% (2013: 0.1%) variance in the net book value of oil and gas properties.

Recoverability of oil and gas assets (Note 9)

The Group assesses each asset or CGU (excluding goodwill, which is assessed annually regardless of indicators) each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, a formal estimate of the recoverable amounts is made, which is considered to be the higher of fair value less costs to sell and value in use. These assessments require the use of estimates and assumptions, such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGU.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value for oil and gas assets is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU. Management has assessed its CGUs as being an individual field, which is the lowest level for which cash inflows are largely independent of those of other assets.

Decommissioning costs (Note 22)

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represent management's best estimate of the present value of the future decommissioning costs required. If the estimated pre-tax discount rate used in the calculation had been 1% higher than management's estimate, the carrying amount of the provision would have been US$3,567,007 (2013: US$2,385,046) lower.

Fair value measurement (Note 28)

The Group measures financial instruments, such as derivatives, at fair value at each balance sheet date. The fair values of these financial instruments are disclosed in Note 28.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

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.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Taxes (Note 7)

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws, and the amount and timing of future taxable income. Given the wide range of international business relationships and the long-term nature and complexity of existing contractual agreements, differences arising between the actual results and the assumptions made, or future changes to such assumptions, could necessitate future adjustments to tax income and expense already recorded. The Group establishes provisions, based on reasonable estimates, for possible consequences of audits by the tax authorities of the respective counties in which it operates. The amount of such provisions is based on various factors, such as experience of previous tax audits and differing interpretations

of tax regulations by the taxable entity and the responsible tax authority. Such differences of interpretation may arise on a wide variety of issues depending on the conditions prevailing in the respective domicile of the Group companies.

Deferred tax assets are recognised for unused tax losses to the extent that it is probable that taxable profit will be available against which the losses can be utilised. Significant management judgement is required to determine the amount of deferred tax assets that can be recognised, based upon the likely timing and the level of future taxable profits together with future tax planning strategies.

The Group has US$39,110,165 (2013: US$38,113,630) of tax losses carried forward. These losses relate to subsidiaries that have a history of losses, do not expire and may not be used to offset taxable income elsewhere in the Group. The subsidiaries have no taxable temporary differences nor any tax planning opportunities available that could partly support the recognition of these losses as deferred tax assets. On this basis, the Group has determined that it cannot recognise deferred tax assets on the tax losses carried forward. Further details on taxes are disclosed in Note 7.

Defined benefit plan (Note 23)

The cost of defined benefit pension plans and the present value of the pension obligation are determined using actuarial valuations. The actuarial valuation involves making various assumptions. These include the determination of the discount rates, expected rates of return of assets, future salary increases, mortality rates and future pension increases. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, defined benefit obligations are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date. The net benefit liability as at 31 December 2014 is US$1,483,647 (2013: US$884,691).

In determining the appropriate discount rate, management considers the interest rates of high quality government bonds. The mortality rate is based on publicly available mortality tables for the specific country and is modified accordingly with estimates of mortality improvements. Future salary increases and pension increases are based on expected future inflation rates for the specific country. Further details about the assumptions used are provided in Note 23.

3.2 KEY SOURCES OF ESTIMATION UNCERTAINTY

The key assumptions concerning the future and other key sources of estimation uncertainty at the end of the reporting period are discussed below. The Group based its assumptions and estimates on parameters available when the financial statements were prepared. Existing circumstances and assumptions about future developments, however, may change due to market changes or circumstances arising beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

(a) Impairment of intangible assets

As disclosed in Note 11 to the financial statements, the recoverable amounts of the CGUs which goodwill and other intangible assets have been allocated to are determined based on value in use calculations. The value in use calculations are based on discounted cash flow models. The recoverable amount is most sensitive to the discount rate used for the discounted cash flow model as well as the expected cash inflows and the long term oil prices assumptions used for extrapolation purposes. The key assumptions applied in the determination of the value in use including a sensitivity analysis, are disclosed and further explained in Note 11 to the financial statements.

The carrying amount of the intangible assets as at 31 December 2014 is US$91,452,905 (2013: US$43,890,735).

(b) Impairment of loans and receivables

The Group assesses at the end of each reporting period whether there is any objective evidence that a financial asset is impaired. Factors such as the probability of insolvency or significant financial difficulties of the debtor and default or significant delay in payments are objective evidence of impairment. In determining whether there is objective evidence of impairment, the Group considers whether there is observable data indicating that there have been significant changes in the debtor's payment ability or whether there have been significant changes with adverse effect in the technological, market, economic or legal environment in which the debtor operates in.

Where there is objective evidence of impairment, the amount and timing of future cash flows are estimated based on historical loss experience for assets with similar credit risk characteristics. The carrying amount of the Group's loans and receivables at the end of the reporting period is disclosed in Note 16 to the financial statements.

4 BUSINESS COMBINATIONS

Acquisition in 2014

KrisEnergy G10 (Thailand) Ltd. ["KEG10"]

On 27 May 2014, the Group completed its acquisition of a 100% equity interest in KrisEnergy G10 (Thailand) Ltd. (formerly known as MP G10 (Thailand) Limited) which holds a 75% working interest in, and operatorship of, the G10/48 licence in the Gulf of Thailand from Mubadala Petroleum, for a consideration of US$106,488,195. The Group has acquired KEG10 to expand its development portfolio which is key to near-term growth in reserves and production.

The fair value of the identifiable assets and liabilities of KEG10 as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets:	
Exploration and evaluation assets	56,238,116
Inventories	138,129
Trade and other receivables	280,739
Cash and bank balances	4,848,569
	61,505,553
Liabilities:	
Trade and other payables	89,877,629
Total identifiable net liabilities at fair value	(28,372,076)
Intra-group settlement	88,598,387
Goodwill	46,261,884
Consideration settled in cash	106,488,195
Less: cash and bank balances	(4,848,569)
Net cash outflow on acquisition	101,639,626

The carrying value of the trade and other receivables amounting to US$280,739 was an approximate of its fair value. None of the trade and other receivables has been impaired and it was expected that the full contractual amounts can be collected.

Included in trade and other payables is KEG10 intra-group debts of US$88,598,387, which is included as part of the cash consideration paid to Mubadala Petroleum.

The goodwill of US$46,261,884 comprises the value of strengthening the Group's portfolio for development assets held in the region. None of the goodwill is expected to be deductible for tax purposes.

From the date of acquisition to 31 December 2014, KEG10 did not contribute to Group revenue and has contributed US$280,701 of net loss to the Group. If the business combination had taken place at the beginning of the year, there would be no impact to Group revenue but the loss for the year would have been US$50,422,500.

KrisEnergy (Apsara) Ltd. ["KEAPL"]

On 1 October 2014, the Group completed its acquisition of the entire share capital of KrisEnergy (Apsara) Ltd. (formerly known as Chevron Overseas Petroleum (Cambodia) Limited), which holds a 30% working interest in, and operatorship of, Cambodia Block A, for a consideration of US$65,576,813. The Group has acquired KEAPL to gain operatorship of Cambodia Block A and to steer the Apsara development plans forward to first production as quickly and cost effectively as possible.

The fair value of the identifiable assets and liabilities of KEAPL as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets:	
Exploration and evaluation assets	63,725,851
Trade and other receivables	652,138
	64,377,989
Liabilities:	
Trade and other payables	101,462
Total identifiable net assets at fair value	64,276,527
Goodwill	1,300,286
Consideration settled in cash	65,576,813

The carrying value of the trade and other receivables amounting to US$652,138 was an approximate of its fair value. None of the trade and other receivables has been impaired and it was expected that the full contractual amounts can be collected.

The goodwill of US$1,300,286 comprises the value of strengthening the Group's portfolio for development assets held in the region. None of the goodwill is expected to be deductible for tax purposes.

From the date of acquisition to 31 December 2014, KEAPL did not contribute to Group revenue and contributed US$66,904 of net loss to the Group. If the business combination had taken place at the beginning of the year, there would be no impact to Group revenue but the loss for the year would have been US$50,376,208.

Acquisition in 2013

KrisEnergy Bangladesh Limited ["KEBL"]

On 17 December 2013, the Group completed its acquisition of a 100% equity interest in KrisEnergy Bangladesh Limited (formerly known as Tullow Bangladesh Ltd), which holds 30% working interest in Block 9 Production Sharing Contract ("PSC") from Tullow Oil International Limited, for a consideration of US$41,396,066. The Group has acquired KEBL to build up its portfolio of producing assets in Bangladesh.

As part of the purchase price allocation, management engaged a technical specialist, Netherland, Sewell & Associates, Inc. ("NSAI"), to perform an assessment of the field's reserves and their value as at 31 December 2013. The assumptions and estimates provided by NSAI, together with adjustments made by management formed the basis of valuation.

The fair value of the identifiable assets and liabilities of KEBL as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets:	
Oil and gas properties	42,166,419
Inventories	89,351
Trade and other receivables	22,263,386
	64,519,156
Liabilities:	
Trade and other payables	2,525,258
Total identifiable net assets at fair value	61,993,898
Intra-group settlement	(7,661,546)
Excess of fair value of net assets acquired over consideration paid	(12,936,286)
Consideration settled in cash	41,396,066

The carrying value of the trade and other receivables amounting to US$22,263,386 was an approximate of its fair value. None of the trade and other receivables has been impaired and it is expected that full contractual amounts can be collected.

Included in trade and other receivables is KEBL intra-group receivable of US$7,661,546, which is set-off against the cash consideration paid to Tullow Oil International Limited.

The excess of fair value of net assets acquired over consideration paid of US$12,936,286 arises from the probable, possible and contingent reserves arising from the oil and gas properties acquired.

From the date of acquisition to 31 December 2013, KEBL has contributed US$1,660,915 of revenue and US$221,328 of net profit to the Group. If the business combination had taken place at the beginning of the year, the Group's revenue would have been US$84,514,791 and the loss for the year would have been US$4,913,107.

Transaction costs related to the acquisition of US$245,190 have been recognised in the "general and administrative expenses" line item in the Group's profit or loss for the year ended 31 December 2013.

5 INTERESTS IN OIL AND GAS BLOCKS

The Group holds interests in each contract area for the right to explore and produce oil and gas properties. The Group's interests in oil and gas blocks are listed in the following table.

For each contract area where the Group along with other participant jointly holds interests in, the respective interests are accounted for as joint operations.

CONTRACT AREA (DATE OF EXPIRY)	HELD BY	DESCRIPTION	PLACE OF OPERATION	% OF EFFECTIVE WORKING INTEREST	
				2014	2013
G10/48 Concession (7 December 2015)	KrisEnergy (Gulf of Thailand) Ltd. (25.0%) and KrisEnergy G10 (Thailand) Ltd. (75.0%)	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	100.00	25.00
G11/48 Concession (12 February 2016)	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	22.50	25.00
Cambodia Block PA (No expiry date for exploration stage)	KrisEnergy (Cambodia) Ltd (25.0%) and KrisEnergy (Apsara) Ltd. (30.0%)	Drilling of exploration wells under the Petroleum Agreement ("PA") with General Department of Petroleum (formerly known as Cambodian National Petroleum Authority)	Offshore Cambodia	55.00	25.00
Glagah Kambuna TAC (16 December 2016)	KrisEnergy Glagah-Kambuna B.V.	Exploration and production of petroleum under Technical Assistance Contract ("TAC") with Indonesia Governmental Authority	Indonesia	–	25.00
Kutai PSC (15 January 2037)	KrisEnergy Kutai B.V. (24.6%) and KrisEnergy Kutei B.V. (30.0%)	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	54.60	54.60
B8/32 Concession (31 July 2020)	KrisEnergy (Gulf of Thailand) Ltd. / Orange Energy Ltd. / B8/32 Partners Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	4.63	4.63
B9A Concession (16 July 2041)	KrisEnergy (Gulf of Thailand) Ltd. / Orange Energy Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	4.63	4.63
Block 105 PSC (2 February 2040)[1]	KrisEnergy (Song Hong 105) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority	Offshore Vietnam	33.33	25.00
Block 120 PSC (22 January 2039)[1]	KrisEnergy (Phu Khanh 120) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority	Offshore Vietnam	33.33	25.00
East Seruway PSC (12 November 2038)	KrisEnergy East Seruway B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	100.00	100.00
Bulu PSC (13 October 2033)	KrisEnergy (Satria) Ltd.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	42.50	42.50
East Muriah PSC (12 November 2038)	KrisEnergy (East Muriah) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	50.00	50.00
Tanjung Aru PSC (18 December 2041)[2]	KrisEnergy (Tanjung Aru) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	85.00	43.00
Udan Emas PSC (19 July 2042)	KrisEnergy (Udan Emas) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	100.00	100.00
Block 9 PSC (26 August 2033)	KrisEnergy Bangladesh Limited	Exploration and production of petroleum under Production Sharing Contract with Bangladesh Governmental Authority	Bangladesh	30.00	30.00
G6/48 Concession (7 January 2016)	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	30.00	30.00
Sakti PSC (25 February 2044)	KrisEnergy Sakti B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	95.00	–
Block 115/09 (30 March 2044)	KrisEnergy (Asia) Ltd.	Exploration and development of petroleum under Production Sharing Contract	Offshore Vietnam	100.00	–

CONTRACT AREA (DATE OF EXPIRY)	HELD BY	DESCRIPTION	PLACE OF OPERATION	% OF EFFECTIVE WORKING INTEREST	
				2014	2013
Block SS-11 PSC (11 March 2019)	KrisEnergy (Asia) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Bangladesh Governmental Authority	Bangladesh	45.00	–
Block A Aceh PSC[3] (31 August 2031)	KrisEnergy (Block A Aceh) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	41.67	–

NOTES:

(1) Pursuant to the deed executed in relation to the default and subsequent withdrawal of Neon Energy from Block 105 PSC and Block 120 PSC, Neon Energy's working interest is proportionately transferred to Eni Vietnam B.V., KrisEnergy (Song Hong 105) Ltd and KrisEnergy (Phu Khanh 120) Ltd. As at 31 December 2014, the government approvals had not been received. On 13 February 2015, the approvals for the revised working interest have been received from the Ministry of Industry and Trade of Vietnam.

(2) Pursuant to the deed executed in relation to the default and subsequent withdrawal of Neon Energy from Tanjung Aru PSC, Neon Energy's working interest is transferred to KrisEnergy (Tanjung Aru) B.V. As at 31 December 2014, the government approval had not been received.

(3) On 1 July 2014, KrisEnergy Asia Holdings B.V. acquired 41.67% working interest in the Block A Aceh PSC. As at 31 December 2014, the government approvals had not been received. On 12 January 2015, approval for the change of control has been received from the Government of Indonesia and the provincial government of Aceh.

6 (LOSS)/PROFIT BEFORE TAX

The following items have been included in arriving at (loss)/profit before tax:

GROUP	NOTE	2014 US$	2013 US$
Revenue:			
Sale of crude oil		49,792,944	54,663,754
Sale of gas		25,112,285	14,386,649
		74,905,229	**69,050,403**
Cost of sales:			
Depletion and amortisation of oil and gas properties	9	(28,714,703)	(20,056,305)
Exploration and operating costs		(19,192,177)	(16,113,008)
Thai Petroluem royalties and remuneration paid		(7,329,327)	(8,084,747)
Overprovision of decommissioning cost	22	–	667,226
		(55,236,207)	**(43,586,834)**
Other income is mainly made up of the following items:			
Excess of fair value of net assets acquired over consideration paid	4	–	12,936,286
Income from transfer of joint study arrangement		1,038,279	–
Joint operator overhead charges		1,248,246	1,285,389
Net foreign exchange differences		69,309	66,806
Income from shared facilities in joint operations		808,486	437,864
Income from technical services provided to joint operations		3,695,855	–
Value added tax recovered		1,747,694	609,063
General and administrative expenses is mainly made up of the following items:			
Consultants' fees		(770,916)	(690,491)
Data purchase and subscriptions		(810,133)	(1,073,840)
Database rental		(1,351,419)	(669,898)
Depreciation of other property, plant and equipment	10	(426,676)	(348,379)
Employee benefits expense:			
• Salaries and bonuses		(15,460,439)	(16,813,350)
• Share-based payments	24	(3,122,919)	(674,582)
• Central Provident Fund Contributions		(274,696)	(250,575)
• Employee defined benefit		(226,224)	(884,691)
• Other short-term benefits		(709,924)	(774,305)

GROUP	NOTE	2014 US$	2013 US$
Operating lease expense		(794,194)	(814,250)
Professional fees		(6,012,737)	(4,529,631)
Travel and entertainment		(1,780,528)	(1,636,740)
Other operating (expenses)/income is mainly made up of the following items:			
Loss on disposal of investment securities	13	(182,057)	–
Joint study expenses		(703,902)	(653,387)
Net fair value (loss)/gain on embedded derivatives	12	(6,137,226)	2,284,698
Net fair value loss on hedge	25	(2,960,446)	–
Finance income:			
Interest income from banks		577,251	1,853,888
Finance Costs:			
Accretion of interest on bonds		–	(260,421)
Financing fees		(6,849,814)	(1,568,368)
Interest on bank borrowings		(591,733)	–
Interest and redemption premium on callable bonds		(8,193,618)	(11,073,410)
Interest on multi-currency medium term notes		(6,875,962)	–
Unwinding of discount on decommissioning provisions	22	(642,073)	(431,792)
		(23,153,200)	**(13,333,991)**

Thai Petroleum royalties and remuneration paid

Under the terms of the Thai I regime, the concessionaire is required to pay production royalties to the Royal Thai Government computed based on 12.5% of value of petroleum sold for payment in cash and in kind respectively.

Under the Thai III regime, the concessionaire is required to pay production royalties to the Royal Thai Government computed based on sliding scale rates from 5% to 15% of the value of petroleum sold or disposed during the month, depending on the number of barrels sold or disposed during the month.

Special remuneration benefit ("SRB") is tax payable only in years concessionaire has petroleum profit. In calculating such profit (or loss), capital expenditure, operating costs and a special reduction of 35% operating expenses for the year and petroleum loss carried forward indefinitely from prior years may be deducted. SRB is calculated by exploration block on income per meter of well, subject to a ceiling of 75% of petroleum profit.

Loss per share

Basic loss per share is calculated by dividing loss for the year attributable to owners of the Company by the weighted average number of ordinary shares outstanding during the financial year.

Diluted loss per share is calculated by dividing loss for the year attributable to owners of the Company by the weighted average number of ordinary shares outstanding during the financial year plus the weighted average number of ordinary shares that would be issued on the vesting of all performance shares under the Performance Share Plan (Note 24).

The following tables reflect the profit and share data used in the computation of basic and diluted loss per share for the years ended 31 December:

GROUP	2014 US$	2013 US$
Loss for the year attributable to owners of the Company used in the computation of basic and diluted loss per share	(50,370,496)	(12,645,133)

	2014 NO. OF SHARES	2013 NO. OF SHARES
Weighted average number of ordinary shares for basic loss per share computation	1,046,967,214	547,565,929
Effects of dilution:		
• Vesting of performance shares	4,616,475	728,917
Weighted average number of ordinary shares for diluted loss per share computation	1,051,583,689	548,294,846

7 TAXATION

The major components of tax expense for the years ended 31 December 2014 and 2013 are:

GROUP	2014 US$	2013 US$
Current tax:		
• Current tax charge	12,782,388	14,181,088
• Overprovision in respect of previous years	(90,717)	(1,587,619)
	12,691,671	12,593,469
Deferred tax:		
• (Reversal)/origination of temporary differences	(1,600,045)	165,160
Tax expense recognised in profit or loss	**11,091,626**	**12,758,629**

Relationship between tax expense and accounting (loss)/profit

A reconciliation between tax expense and the accounting (loss)/profit multiplied by the applicable tax rate for the years ended 31 December 2014 and 2013 is as follows:

GROUP	2014 US$	2013 US$
(Loss)/profit before tax	(39,278,870)	113,496
Tax at domestic rates applicable in the countries where the Group operates	5,250,245	10,453,621
Adjustments		
Non-deductible expenses	363,592	158,424
Income not subject to tax	375,382	–
Deferred tax assets not recognised	5,216,307	3,760,858
Effect of partial tax exemption and tax relief	(19,932)	(20,701)
Overprovision in respect of previous years	(90,717)	(1,587,619)
Others	(3,251)	(5,954)
Tax expense recognised in profit or loss	**11,091,626**	**12,758,629**

The above reconciliation is prepared by aggregating separate reconciliation for each national jurisdiction.

The nature of expenses that is not deductible for tax purposes are mainly made up of the following items.

GROUP	2014 US$	2013 US$
Unrealised foreign exchange loss	325,607	134,262

Deferred tax

Deferred tax at 31 December relates to the following:

GROUP	CONSOLIDATED STATEMENT OF FINANCIAL POSITION		CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME	
	2014 US$	2013 US$	2014 US$	2013 US$
Deferred tax liabilities				
Fair value adjustment on acquired reserves	41,339,217	42,660,419	(1,321,202)	(1,310,583)
Deferred tax assets				
Provisions	(1,029,577)	(750,734)	(278,843)	1,475,743
Deferred tax (benefit)/liability			**(1,600,045)**	**165,160**
Net deferred tax liabilities	**40,309,640**	**41,909,685**		

GROUP	2014 US$	2013 US$
Differences in depreciation, depletion and amortisation for tax purposes	48,581,470	44,361,697
Unutilised tax losses	39,110,165	38,113,630
	87,691,635	**82,475,327**

The Group offsets tax assets and liabilities if and only if it has a legally enforceable right to set off current tax assets and current tax liabilities and the deferred tax assets and deferred tax liabilities relate to income taxes levied by the same tax authority.

Deferred tax assets have not been recognised in respect of these temporary differences and tax losses as they may not be used to offset taxable profits elsewhere in the Group, they have arisen in subsidiaries that have been loss-making for some time, and there are no other tax planning opportunities or other evidence of recoverability in the near future. The use of these tax losses is subject to the agreement of the tax authorities and compliance with certain provisions of the tax legislation of the respective countries in which the companies operates.

8 EXPLORATION AND EVALUATION ASSETS

GROUP	NOTE	2014 US$	2013 US$
Cost:			
At 1 January		200,261,113	135,653,818
Additions		82,553,592	64,607,295
Acquisition of subsidiaries	4	119,963,967	–
At 31 December		**402,778,672**	**200,261,113**

9 OIL AND GAS PROPERTIES

GROUP	NOTE	US$
Cost:		
At 1 January 2013		241,532,829
Additions		13,794,344
Acquisition of subsidiary	4	42,166,419
At 31 December 2013 and 1 January 2014		297,493,592
Additions		24,453,401
As at 31 December 2014		321,946,993
Depletion, amortisation and impairment:		
At 1 January 2013		136,841,206
Charge for the year		20,056,305
At 31 December 2013 and 1 January 2014		156,897,511
Charge for the year		28,714,703
As at 31 December 2014		185,612,214
Net book value:		
As at 31 December 2014		136,334,779
As at 31 December 2013		140,596,081

10 OTHER PROPERTY PLANT AND EQUIPMENT

GROUP	RENOVATION	FURNITURE AND FITTINGS	OFFICE EQUIPMENT	COMPUTERS	TOTAL
	US$	US$	US$	US$	US$
Cost:					
At 1 January 2013	839,055	52,149	27,662	769,794	1,688,660
Additions	123,537	53,087	17,430	233,821	427,875
Exchange differences	(17,272)	(678)	(302)	(17,164)	(35,416)
At 31 December 2013 and 1 January 2014	945,320	104,558	44,790	986,451	2,081,119
Additions	696,852	107,315	122,905	344,630	1,271,702
Disposals	(92,390)	(46,098)	(10,275)	(32,647)	(181,410)
Exchange differences	(34,897)	(545)	(151)	(29,223)	(64,816)
At 31 December 2014	1,514,885	165,230	157,269	1,269,211	3,106,595
Accumulated depreciation:					
At 1 January 2013	754,138	39,486	18,175	622,092	1,433,891
Charge for the year	98,013	37,999	13,710	198,657	348,379
Exchange differences	(17,445)	(684)	(277)	(14,970)	(33,376)
At 31 December 2013 and 1 January 2014	834,706	76,801	31,608	805,779	1,748,894
Charge for the year	148,495	33,482	20,210	224,489	426,676
Disposals	(81,775)	(39,553)	(9,487)	(30,601)	(161,416)
Exchange differences	(35,123)	(1,212)	(580)	(31,847)	(68,762)
At 31 December 2014	866,303	69,518	41,751	967,820	1,945,392
Net carrying amount:					
At 31 December 2014	648,582	95,712	115,518	301,391	1,161,203
At 31 December 2013	110,614	27,757	13,182	180,672	332,225

11 INTANGIBLE ASSETS

GROUP	NOTE	GOODWILL	OTHERS	TOTAL
		US$	US$	US$
Cost:				
At 1 January 2013, 31 December 2013 and 1 January 2014		58,477,823	1,669,721	60,147,544
Acquisition of subsidiaries	4	47,562,170	–	47,562,170
At 31 December 2014		106,039,993	1,669,721	107,709,714
Accumulated amortisation and impairment loss:				
At 1 January 2013, 31 December 2013, 1 January 2014 and 31 December 2014		16,256,809	–	16,256,809
Net carrying amount:				
At 31 December 2014		89,783,184	1,669,721	91,452,905
At 31 December 2013		42,221,014	1,669,721	43,890,735

Goodwill

Goodwill arises principally because of the following factors:

(a) The going concern value implicit in our ability to sustain and/or grow our business by increasing reserves and resources through new discoveries

(b) The ability to capture unique synergies that can be realised from managing a portfolio of both acquired and existing fields

(c) The requirement to recognise deferred tax assets and liabilities for the difference between the assigned values and the tax bases of assets acquired and liabilities assumed in a business combination at amounts that do not reflect fair value.

Other intangible assets

GROUP	2014 US$	2013 US$
0.75% overriding royalty interest in G10/48 and G11/48 Concessions	1,300,000	1,300,000
Leasehold bonus for G10/48 Concession	269,721	269,721
Block 105 PSC	100,000	100,000
	1,669,721	**1,669,721**

The Group was assigned the overriding royalty interest from the acquisitions of KrisEnergy Oil and Gas (Thailand) Ltd ("KEOG") and KrisEnergy Resources (Thailand) Ltd ("KER"). The overriding royalty interest entitles the Group rights to the revenues derived from the production and disposal of all of the oil, gas, and other minerals, in, on, under, and that may be produced and saved from G10/48 and G11/48 Concessions.

The useful lives of these other intangible assets are estimated to be indefinite as the exploration period of the blocks are extended every three years and cannot be reliably estimated. Renewals have historically been granted and entail minimal costs.

Impairment testing

For impairment testing purposes, goodwill and other intangible assets acquired through business combinations have been allocated as follows:

	GOODWILL		OTHERS	
GROUP	2014 US$	2013 US$	2014 US$	2013 US$
G10/48 and G11/48 Concessions	21,774,832	21,774,832	1,569,721	1,569,721
G10/48 Concession	46,261,884	–	–	–
B9A and B8/32 Concessions	13,301,576	13,301,576	–	–
Bulu PSC	7,144,606	7,144,606	–	–
Block 105 PSC	–	–	100,000	100,000
Cambodia Block A PA	1,300,286	–	–	–
	89,783,184	**42,221,014**	**1,669,721**	**1,669,721**

The recoverable amount of each field is determined on a value-in-use calculation.

The calculation of value in use of the oil exploration and production CGU is most sensitive to the following assumptions:

- Production volumes
- Discount rates
- Crude oil prices

Estimated production volumes are based on detailed date for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. It is estimated that, if all production were to be reduced by 2% for the whole term of the contract area, this would not be sufficient to reduce the excess of recoverable amount over the carrying amounts of the individual CGUs to zero. Consequently, management believes no reasonably possible change in the production assumptions would cause the carrying amount of goodwill and/or other non-current assets to exceed their recoverable amount.

The Group generally estimates value in use for the oil exploration and production CGU using a discounted cash flow model. The future cash flows are discounted to their present value using a pre-tax discount rate of 8% to 10% (2013 : 8% to 10%) that reflects current market assessments of the time value of money and the risks specific to the asset. The discount rate is derived from the Group's weighted average cost of capital with appropriate adjustments made to reflect the risks specific to the CGU.

Oil prices are based on Brent future prices at the reporting date and adjusted for quality, transportation fees and regional price differences. The Group's calculation incorporates a range of oil prices from US$60 to US$90 (2013 : US$90 to US$110) per barrel.

12 EMBEDDED DERIVATIVES

The Group issued KEHCL Callable Bonds (Note 21) which have embedded derivatives arising from the call option on the bond. These require bifurcation and are separately recognised and accounted for at fair value with any changes to fair value credited or charge to profit or loss.

On 30 January 2014, the Group exercised its option to redeem the KEHCL Callable Bonds in whole. The carrying value of the embedded derivatives amounted to US$6,137,226 was fully charged to other operating (expenses)/income (Note 6).

13 INVESTMENT SECURITIES

GROUP	2014 US$	2013 US$
Available for sale investments:		
Unquoted equity shares, at cost	–	182,057

During the financial year, the Group recognised a loss on disposal of US$182,057 (Note 6) for the unquoted equity shares as the shareholders agreement was terminated on 17 July 2014.

14 INVESTMENT IN SUBSIDIARIES

COMPANY	NOTE US$	2014 US$	2013 US$
Unquoted shares, at cost		326,759,705	326,759,655
Capital contribution for share-based payments	24	3,797,501	674,582
		330,557,206	**327,434,237**

The Group has the following investment in subsidiaries:

NAME OF ENTITIES	PRINCIPAL ACTIVITIES	PRINCIPAL PLACE OF BUSINESS	COUNTRY OF INCORPORATION	% OF EQUITY INTEREST 2014	% OF EQUITY INTEREST 2013
KrisEnergy Holding Company Ltd[1][2][3][6]	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy Pte. Ltd.[1][2][3]	Provision of management support service	Singapore	Singapore	100	100
KrisEnergy (Management Services) Ltd [1][2][3]	Provision of offshore management support service	Singapore	British Virgin Islands	100	100
KrisEnergy Asia Ltd.[1][2][3][4]	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy International (Thailand) Holdings Ltd[1][2][3]	Investment holding	Thailand	British Virgin Islands	100	100
KrisEnergy (Gulf of Thailand) Ltd.[6]	Investment holding	Thailand	Cayman Islands	100	100
KrisEnergy Oil and Gas (Thailand) Ltd	Exploration and production of oil and gas	Thailand	Thailand	100	100
KrisEnergy Resources (Thailand) Ltd	Exploration and production of oil and gas	Thailand	Thailand	100	100
KrisEnergy Management Ltd	Dormant	Singapore	British Virgin Islands	100	100
KrisEnergy (Cambodia) Holding Ltd[1][2][3]	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy (Cambodia) Ltd	Exploration and production of oil and gas	Cambodia	Cambodia	100	100
KrisEnergy (Phu Khanh 120) Ltd[1][2][3]	Exploration and production of oil and gas	Vietnam	British Virgin Islands	100	100

NAME OF ENTITIES	PRINCIPAL ACTIVITIES	PRINCIPAL PLACE OF BUSINESS	COUNTRY OF INCORPORATION	% OF EQUITY INTEREST	
				2014	2013
KrisEnergy (Song Hong 105) Ltd[1][2][3]	Exploration and production of oil and gas	Vietnam	British Virgin Islands	100	100
KrisEnergy (Vietnam) Ltd	Dormant	Singapore	British Virgin Islands	100	100
KrisEnergy Asia Coöperatief U.A.[6]	Investment holding	Singapore	The Netherlands	100	100
KrisEnergy Asia Holdings B.V.[1][6]	Investment holding	Singapore	The Netherlands	100	100
KrisEnergy Glagah-Kambuna B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Bangora) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Kutai B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Andaman II) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Marine Pte. Ltd. (Formerly known as KrisEnergy (Development) Pte. Ltd.)[4]	Investment holding	Singapore	Singapore	100	100
KrisEnergy Kutei B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy East Seruway B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Bangladesh SS-11) Ltd	Investment holding	Singapore	British Virgin Islands	100	100
SJ Production Barge Ltd (Formerly known as EM Block Limited)[5]	Exploration and production of oil and gas	Singapore	British Virgin Islands	100	100
B Block Limited	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy (Satria) Ltd	Exploration and production of oil and gas	Indonesia	British Virgin Islands	100	100
KrisEnergy (East Muriah) Ltd	Exploration and production of oil and gas	Indonesia	British Virgin Islands	100	100
KrisEnergy (Ampuh) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Andaman Timur) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Nemo) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Sakti) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Tanjung Aru) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Udan Emas) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Bangladesh Limited[6]	Exploration and production of oil and gas	Bangladesh	Jersey	100	100
KrisEnergy (Apsara) Ltd. (Formerly known as Chevron Overseas Petroleum (Cambodia) Limited)	Exploration and production of oil and gas	Cambodia	Bermuda	100	–
KrisEnergy G10 (Thailand) Ltd. (Formerly known as MP G10 (Thailand) Limited)	Exploration and production of oil and gas	Thailand	Thailand	100	–
KrisEnergy (Block A Aceh) B.V. (Formerly known as Premier Oil Sumatra (North) B.V.)	Exploration and production of oil and gas	Indonesia	The Netherlands	100	–

NOTES:
(1) Capital stock in this entity pledged as collateral for KEHCL Callable Bonds
(2) First priority floating charge provided by this entity over present and future assets as collateral for KEHCL Callable Bonds
(3) Assignment of internal loans by this entity as collateral for KEHCL Callable Bonds
(4) With effect from 16 April 2014, the name of the Company was changed from KrisEnergy (Development) Pte. Ltd. to KrisEnergy Marine Pte. Ltd.
(5) With effect from 3 October 2014, the name of the Company was changed from EM Block Limited to SJ Production Barge Ltd
(6) Capital stock in this entity pledged as collateral for KEAL Revolving Credit Facility

15 INVENTORIES

GROUP	2014 US$	2013 US$
Balance sheet:		
Drilling supplies and materials (at cost)	12,839,947	5,323,207
Crude oil (at cost)	1,830,127	1,703,956
	14,670,074	**7,027,163**
Profit or loss:		
Inventories recognised as an expense in cost of sales	126,170	116,420

16 TRADE AND OTHER RECEIVABLES

		GROUP		COMPANY	
	NOTE	2014 US$	2013 US$	2014 US$	2013 US$
Trade and other receivables (current):					
Trade receivables		7,380,102	15,095,907	–	–
Refundable deposits		498,761	5,489,566	–	–
Other receivables		36,363,553	20,371,158	–	122,982
Joint operation receivables		20,923,075	13,193,081	–	–
		65,165,491	54,149,712	–	122,982
Other receivables (non-current):					
Amount due from subsidiaries		–	–	645,464,973	65,000,000
Total trade and other receivables (current and non-current):		65,165,491	54,149,712	645,464,973	65,122,982
Add: cash and bank balances	17	51,334,088	251,809,697	1,610,557	211,400,012
Less: advances for acquisition		(4,152,697)	–	–	–
Total loans and receivables		**112,346,882**	**305,959,409**	**647,075,530**	**276,522,994**

Other receivables comprise:

	GROUP		COMPANY	
	2014 US$	2013 US$	2014 US$	2013 US$
Advances for acquisition	4,152,697	–	–	–
Payment on behalf of joint operation's partners	7,862,571	4,969,756	–	92,655
Proportionate share of joint operation's other receivables	11,550,095	15,163,811	–	–
Value added tax receivables	12,635,031	221,692	–	–
Others	163,159	15,899	–	30,327
	36,363,553	**20,371,158**	**–**	**122,982**

Trade receivables are non-interest bearing and are generally on 30 days' terms. They are recognised at their original invoice amounts which represent their fair values on initial recognition.

Joint operation receivables and other receivables relate to amounts due from the joint operators for cash calls and expenses incurred on their behalf in excess of the Group's obligation. These amounts are unsecured, non-interest bearing, and will be settled by future cash calls within the next 12 months.

Amount due from subsidiaries are non-trade related, unsecured, non-interest bearing, and repayable upon demand.

Trade and other receivables denominated in foreign currencies at 31 December are as follows:

GROUP	2014 US$	2013 US$
Thai Baht	721,596	182,901

At the reporting date, the Group does not have any receivables that are past due or impaired, or would otherwise be past due but not impaired.

17 CASH AND BANK BALANCES

	GROUP		COMPANY	
	2014 US$	2013 US$	2014 US$	2013 US$
Cash at banks and on hand	47,575,264	247,809,697	1,610,557	211,400,012
Cash collateralised	3,758,824	–	–	–
Short-term deposits	–	4,000,000	–	–
Cash and bank balances	**51,334,088**	**251,809,697**	**1,610,557**	**211,400,012**

Cash at banks earn interest at floating rates based on daily bank deposit rates. Included in cash and bank balances is cash collateralised to a bank of US$3,758,824 under the KEHCL Revolving Credit Facility (Note 21). In 2013, cash and bank balances included a short-term deposit of US$4,000,000 placed with and pledged to a bank for issuance of guarantees on behalf of KrisEnergy (Song Hong 105) Ltd and KrisEnergy (Phu Khanh 120) Ltd. These deposits have a minimum yield of 0.5% per annum. The pledge was released in February 2014.

For the purpose of the consolidated statement of cash flows, cash and cash equivalents comprise the following at 31 December:

GROUP	2014 US$	2013 US$
Cash and bank balances	51,334,088	251,809,697
Less: restricted cash	(3,758,824)	(4,000,000)
Cash and cash equivalents	**47,575,264**	**247,809,697**

Cash at banks and on hand denominated in foreign currencies at 31 December are as follows:

GROUP	2014 US$	2013 US$
Thai Baht	123,826	25,327
Euro Dollar	127,102	218,889
Indonesia Rupiah	9,649	11,306
Singapore Dollar	250,789	19
United States Dollar	356,656	137,184

18 ASSETS HELD FOR SALE

On 23 December 2014, the Group entered into a sale and purchase agreement to dispose of the mobile production package which includes the mobile offshore production unit ("MOPU"), the catenary anchor leg mooring buoy ("CALM Buoy") and the two hoses that connect from the MOPU to the CALM Buoy ("Manuli Hoses"). As at 31 December 2014, the carrying amount of the assets related to the mobile production package has been presented in the consolidated statement of financial position as "Assets held for sale". The disposal is expected to be completed in 2015.

19 SHARE CAPITAL AND RESERVE

GROUP AND COMPANY

SHARE CAPITAL:	2014		2013	
	NO. OF SHARES	US$	NO. OF SHARES	US$
Issued and fully paid ordinary shares:				
At 1 January	1,046,154,000	1,307,693	100,000,000	1,000,000
One for eight share split on 10 July 2013	–	–	700,000,000	–
Issued on 19 July 2013 for cash	–	–	246,154,000	307,693
Vesting of equity-settled share options to employees on 21 July 2014	1,809,898	2,262	–	–
At 31 December	**1,047,963,898**	**1,309,955**	**1,046,154,000**	**1,307,693**

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. All ordinary shares carry one vote per share without restrictions. The ordinary shares have a par value of US$0.00125 (2013: US$0.00125) each.

GROUP AND COMPANY

SHARE PREMIUM:	2014	2013
	US$	US$
At 1 January	602,938,278	402,750,000
Increase on 19 July 2013 for cash arising from an issuance of share capital	–	212,678,368
Share issuance expense	–	(12,490,090)
Vesting of equity-settled share options to employees on 21 July 2014	1,644,490	–
At 31 December	**604,582,768**	**602,938,278**

Foreign currency translation reserve

The foreign currency translation reserve represents exchange differences arising from the translation of the financial statements of foreign subsidiaries whose functional currencies are different from that of the Group's presentation currency.

Employee share option reserve

Employee share option reserve represents equity-settled share options granted to employees (Note 24). The reserve is made up of the cumulative value of services received from employees recorded over the vesting period commencing from the grant date of equity-settled share options, and is reduced by the expiry or exercise of the share options.

20 TRADE AND OTHER PAYABLES

	NOTE	GROUP 2014 US$	GROUP 2013 US$	COMPANY 2014 US$	COMPANY 2013 US$
Trade and other payables (current):					
Trade payables		5,769,552	4,409,349	–	–
Joint operation payables		315,926	1,802,119	–	–
Staff payroll and bonus payables		4,429,846	3,877,401	–	–
Other payables		16,877,701	25,901,132	3,770,137	26,130
		27,393,025	35,990,001	3,770,137	26,130
Other payables (non-current):					
Amount due to subsidiaries		–	–	119,062,800	281,741
Total trade and other payables (current and non-current):		27,393,025	35,990,001	122,832,937	307,871
Accrued operating expenses		20,191,470	13,012,320	275,728	594,103
Loans and borrowings	21	257,440,512	119,141,003	247,440,512	–
Employee benefit liability	23	1,483,647	884,691	–	–
Total financial liabilities carried at amortised cost		**306,508,654**	**165,150,614**	**370,549,177**	**901,974**

Trade payables are non-interest bearing and are normally settled on 60-day terms.

Joint operation payables are cash calls due to the operator of joint operations. These amounts are unsecured, non-interest bearing, and are to be settled in cash.

Other payables comprise:

	GROUP 2014 US$	GROUP 2013 US$	COMPANY 2014 US$	COMPANY 2013 US$
G11/48 deed of deposit refund	–	3,089,447	–	–
Proportionate share of joint operation's other payables	2,033,596	17,034,825	–	–
Accrued interest payable for callable bonds	–	5,580,979	–	–
Accrued interest payable for multi-currency medium term note	3,744,039	–	3,744,039	–
Deposit on asset held for sale	11,000,000	–	–	–
Others	100,066	195,881	26,098	26,130
	16,877,701	**25,901,132**	**3,770,137**	**26,130**

Included in accrued operating expenses is the Group's proportionate share of joint operation's accrued expenses amounting to US$15,009,734 (2013: US$11,779,274).

Amount due to subsidiaries are unsecured, non-interest bearing and repayable on demand.

Trade and other payables denominated in foreign currencies at 31 December are as follows:

GROUP	2014 US$	2013 US$
Thai Baht	694,458	376,572

21 LOANS AND BORROWINGS

	MATURITY	GROUP 2014 US$	GROUP 2013 US$	COMPANY 2014 US$	COMPANY 2013 US$
Current:					
Callable bonds	2014	–	119,141,003	–	–
Non-current:					
Revolving credit facility	2015	10,000,000	–	–	–
Multi-currency medium term notes	2017/2018	247,440,512	–	247,440,512	–
		257,440,512	**119,141,003**	**247,440,512**	**–**

2014

KEL Multi-currency Medium Term Note

On 26 May 2014, the Company established a S$500.0 million Multi-currency Medium Term Note Program ("MMTN Program") with The Hongkong and Shanghai Banking Corporation Limited and Standard Chartered Bank. Under the MMTN Program, the Company issued a S$130.0 million three-year fixed rate bond on 9 June 2014 (the "2017 Notes"), with a coupon of 6.25%. On 22 August 2014, the Company issued another S$200.0 million four-year fixed rate notes with a coupon of 5.75% (the "2018 Notes").

KEAL Revolving Credit Facility

On 24 March 2014, KrisEnergy (Asia) Ltd ("Borrower"), a wholly owned subsidiary of the Company, entered into a facility agreement with The Hongkong and Shanghai Banking Corporation for a US$100.0 million revolving credit facility ("KEAL Revolving Credit Facility") for a period of two years with an option to extend to three years.

As at 31 December 2014, the Borrower has drawn down US$10.0 million and issued bank guarantees of US$9.3 million from the KEAL Revolving Credit Facility. The interest rate of the facility is at LIBOR plus 2.95% per annum and has no fixed repayment term.

The Parent Guarantors of the KEAL Revolving Credit Facility are the Company and KrisEnergy Holding Company Ltd. The Subsidiary Guarantors are KrisEnergy International (Thailand) Holdings Ltd, KrisEnergy Asia Coöperatief UA, KrisEnergy Asia Holdings B.V., KrisEnergy (Gulf of Thailand) Ltd. and KrisEnergy Bangladesh Limited.

Please refer to Note 14 for subsidiaries that provide the above collaterals.

2013

KEHCL Callable Bonds

KrisEnergy Holding Company Ltd ("Issuer"), a wholly owned subsidiary of the Company, issued a US$85.0 million 10.5% Senior Guaranteed Secured Bonds ("KEHCL Callable Bonds") due 21 July 2016 at issue price of 92.3%. Interest on the KEHCL Callable Bonds will accrue at the rate of 10.5% per annum and will be payable semi-annually in arrears on 21 January and 21 July in each year, commencing on 21 January 2012.

On 31 May 2013, the Issuer issued an additional US$35.0 million KEHCL Callable Bonds under the same terms, including the same interest rate and maturity date, increasing the total principal amount of the KEHCL Callable Bonds to US$120.0 million. This issue was priced at 105% of the face value.

The KEHCL Callable Bonds include an option for the Issuer to redeem all or a part of the KEHCL Callable Bonds at the redemption prices, giving rise to an embedded derivative that require bifurcation and it is separately recognised and accounted for at fair value (Note 12).

On 30 January 2014, the Issuer exercised its option to redeem the KEHCL Callable Bonds in whole, at a redemption price of 105.25% of the principal amount. The finance costs on early redemption are presented in Note 6.

All obligations with respect to the KEHCL Callable Bonds are secured as follows:

(a) A first priority pledge over all of the share capital in certain subsidiaries and KrisEnergy (Gulf of Thailand) Ltd.'s equity interest in B8/32 Partners Ltd and Orange Energy Ltd;

(b) A first priority floating charge granted by certain subsidiaries over each of their present and future assets;

(c) An first priority assignment by certain subsidiaries of each of their present and future money claims under the internal loans; and

(d) A pledge by KrisEnergy Asia Holdings B.V. of its present and future receivables under the internal loans and certain insurances in relation to hydrocarbon assets.

KEHCL Revolving Credit Facility

On 21 July 2012, the Issuer entered into a credit agreement with banks for a US$30.0 million revolving credit facility ("KEHCL Revolving Credit Facility"). On 31 May 2013, the Issuer increased its KEHCL Revolving Credit Facility to US$42.5 million.

The KEHCL Revolving Credit Facility has an interest rate of LIBOR plus an applicable margin ranging from 4.0% to 5.0% (in increments of 0.25%), depending on the percentage of commitment utilised at the relevant time. The KEHCL Revolving Credit Facility is used to finance the Group's working capital requirements, capital expenditure, acquisitions and payment of fees, costs and expenses related to the KEHCL Callable Bonds and KEHCL Revolving Credit Facility.

As at 31 December 2013, there is no amount drawn down under the KEHCL Revolving Credit Facility.

The Parent Guarantor of the KEHCL Callable Bonds and KEHCL Revolving Credit Facility is the Company and the Subsidiary Guarantors are KrisEnergy Asia Coöperatief U.A., KrisEnergy Ltd, KrisEnergy Glagah-Kambuna B.V., Kutai B.V., KrisEnergy Nam Con Son B.V., KrisEnergy Oil & Gas (Thailand) Ltd, KrisEnergy Resources (Thailand) Ltd, KrisEnergy (Gulf of Thailand) Ltd., KrisEnergy (Cambodia) Ltd, KrisEnergy (Phu Khanh 120) Ltd. and KrisEnergy (Song Hong 105) Ltd.

Please refer to Note 14 for subsidiaries that provide the above collaterals. The guarantees and collaterals for the KEHCL Callable Bonds and KEHCL Revolving Credit Facility are released on KEHCL Callable Bonds redemption in January 2014.

22 PROVISIONS

GROUP	US$
Decommissioning provisions:	
At 1 January 2013	24,524,643
Arising during the year	1,284,797
Write-back of unused provisions	(667,226)
Unwinding of discount	431,792
Utilisation	(1,832,774)
At 31 December 2013 and 1 January 2014	23,741,232
Arising during the year	14,218,838
Unwinding of discount	642,073
At 31 December 2014	**38,602,143**

The Group provides for the future cost of decommissioning oil production facilities and pipelines on a discounted basis on the installation of those facilities.

The decommissioning provision represents the present value of decommissioning costs relating to oil and gas properties, which are expected to be incurred up to 2041, which is when the producing oil and gas properties are expected to cease operations. These provisions have been created based on the Group's internal estimates. Assumptions based on the current economic environment have been made, which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required that will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

The discount rate used in the calculation of the provisions as at 31 December 2014 equalled 2.6% (2013: 3.4%).

23 EMPLOYEE BENEFIT LIABILITY

The Group has defined benefit pension plans for its employee in Indonesia and Thailand. The plans are governed by the local labour laws, and all local permanent employees are entitled to the plan. Salary is a basis of payment for severance and service benefits which consist of basis salary plus fixed allowances.

The amount included in the consolidated statement of financial position arising from the Group's obligation in respect of its defined benefit pension plans are as follows:

GROUP	2014 US$	2013 US$
Present value of defined benefit obligations	1,344,508	884,691
Re-measurement of defined benefit obligations	139,139	–
Net liability arising from defined benefit obligations	**1,483,647**	**884,691**

Changes in present value of the defined benefit obligations are as follows:

GROUP	US$
At 1 January 2013	–
Interest cost	57,708
Current service cost	601,903
Past service cost	225,080
At 31 December 2013 and 1 January 2014	884,691
Interest cost	71,662
Current service cost	432,430
Past service cost	39,858
Re-measurement (gains)/losses	
Actuarial gains and losses arising from changes in demographic assumption	(502)
Actuarial gains and losses arising from changes in financial assumption	100,823
Actuarial gains and losses arising from experience adjustments	184,133
Benefits paid	(164,426)
At 31 December 2014	**1,483,647**

The cost of the defined benefit pension plans and the present value of the defined benefit obligations are determined using actuarial valuations. The actuarial valuation involves making various assumptions. The principal assumptions used in determining defined benefit obligations are shown below:

	2014	2013
Retirement age	55 – 65 years	58 years
Discount rate	3.5% - 8% per annum	9% per annum
Long-term salary increase	5% - 8% per annum	5% per annum
Expected return on plan assets	n.a.	n.a.
Voluntary resignation	6% for employee before the age of 30 and linear decrease until 0% at the age of 55	6% for employee before the age of 30 and linear decrease until 0% at the age of 52

The sensitivity analysis below has been determined based on reasonably possible changes of each significant assumption on the defined benefit obligations as of the end of the reporting period, assuming if all other assumptions were held constant:

		2014 US$	2013 US$
Discount rate	+ 50 basis points	(45,272)	(18,845)
	- 50 basis points	50,880	19,847
Long-term salary increase	+ 0.5%	50,198	20,440
	- 0.5%	(45,436)	(19,555)

24 SHARE-BASED PAYMENTS

The expenses recognised for employee services received during the year are shown in the following table:

GROUP	2014 US$	2013 US$
Expense arising from cash-settled share-based payment transactions	314,573	146,735
Expense arising from equity-settled share-based payment transactions	2,808,346	527,847
	3,122,919	**674,582**

Virtual Shares Award ("VSA")

On 18 September 2013, the Company awarded 783,764 virtual shares to its employees under the VSA scheme. This VSA is a performance based share incentive scheme to reward eligible employees for their continued contribution to KrisEnergy and to serve as a long-term incentive reward to motivate and retain eligible employees, with a view to align the interests of such employees with the interests of KrisEnergy and its shareholders.

The virtual share represents a cash award which is linked to KrisEnergy's share price. No shares are actually issued or transferred to the employee who has been awarded virtual shares. The cash amount depends on KrisEnergy's closing share price on the relevant vesting date, being 19 July 2014, 19 July 2015 and 19 July 2016, and is calculated based on the number of virtual shares vested on the relevant vesting date multiplied by the vesting share price.

On 1 July 2014 and 24 November 2014, the Company awarded additional 430,874 and 400,770 virtual shares respectively to its employees under the VSA scheme.

On 21 July 2014, 398,881 virtual shares vested at vesting share price of S$0.775.

The carrying amount to the liability relating to the VSA as at 31 December 2014 is US$213,926 (2013: US$146,735).

Performance Share Plan ("PSP")

On 13 November 2013, the Company awarded 5,429,689 performance shares to its employees under the PSP scheme. The PSP is a performance based share incentive scheme to reward selected employees and directors of the Company, who have contributed to the growth and performance of the Group and for their continued support and loyalty, with a direct interest in KrisEnergy.

The shares will be awarded to the selected employees if they remain employed by KrisEnergy with a clean employment record during the relevant vesting period, being 19 July 2014, 19 July 2015 and 19 July 2016. When the shares are fully vested, the shares will be issued and allotted to an account or sub-account with the Central Depository (Pte) Limited ("CDP") in Singapore within ten (10) business days of the vesting date.

On 21 July 2014, 1,809,898 performance shares vested and ordinary shares were issued (Note 19).

On 25 June 2014 and 31 December 2014, the company awarded additional 1,713,111 and 3,473,737 performance shares to its employees under the PSP scheme. The shares will be awarded to selected employees and directors of the Company when certain conditions, which have been predetermined, are achieved during 5 years vesting period.

As at 31 December 2014, the employee share option reserve for the PSP amounts to US$1,689,441 (2013: US$527,847) (Note 19).

There has been no cancellation or modification to the employee share-based payments in 2014.

The fair value of the VSA and PSP are estimated at reporting date and grant date respectively, using a Monte Carlo simulation model, taking into account the terms and conditions upon which the shares were granted. The model simulates a sophisticated random number generator of random variables based on their historical distributions. These variables are then input into a model predicting the price behaviors of the instruments, and the mean of this distribution is taken as the approximate fair value. The valuations are split into three tranches based on the vesting dates.

The following table lists the inputs to the Monte Carlo simulation models for the VSA and PSP respectively. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the share-based payments is indicative of future trends, which may not necessarily be the actual outcome.

VSA:

2014		**TRANCHE 2**	**TRANCHE 3**
Grant Date		18 September 2013 and 1 July 2014	
Share price (S$)		0.63	0.63
Risk free rate (%)		0.72	0.68
Time to vest (years)		0.55	1.55
Expected volatility (%)		29.63	44.06
Annual employee exit rate (%)		3.00	3.00
	TRANCHE 1	**TRANCHE 2**	**TRANCHE 3**
Grant Date		24 November 2014	
Share price (S$)	0.63	0.63	0.63
Risk free rate (%)	0.72	0.68	0.82
Time to vest (years)	0.55	1.55	2.55
Expected volatility (%)	29.63	45.38	42.01
Annual employee exit rate (%)	3.00	3.00	3.00
2013	**TRANCHE 1**	**TRANCHE 2**	**TRANCHE 3**
Grant Date		18 September 2013	
Share price (S$)	1.255	1.255	1.255
Risk free rate (%)	0.29	0.34	0.50
Time to vest (years)	0.55	1.55	2.55
Expected volatility (%)	38.41	38.34	40.05
Annual employee exit rate (%)	5.00	5.00	5.00

PSP:

2014	TRANCHE 1	TRANCHE 2	
Grant Date		25 June 2014	
Share price (S$)	1.65	2.20	
Risk free rate (%)	1.27	1.27	
Time to vest (years)	5.00	5.00	
Expected volatility (%)	40.06	40.06	
Annual employee exit rate (%)	3.00	3.00	
	TRANCHE 1	**TRANCHE 2**	
Grant Date		31 December 2014	
Share price (S$)	0.637	0.630	
Risk free rate (%)	1.60	1.60	
Time to vest (years)	5.00	5.00	
Expected volatility (%)	43.39	43.39	
Annual employee exit rate (%)	3.00	3.00	
2013	**TRANCHE 1**	**TRANCHE 2**	**TRANCHE 3**
Grant Date		13 November 2013	
Share price (S$)	1.195	1.195	1.195
Risk free rate (%)	0.27	0.31	0.39
Time to vest (years)	0.68	1.68	2.68
Expected volatility (%)	41.66	40.69	40.14
Annual employee exit rate (%)	5.00	5.00	5.00

25 DERIVATIVES LIABILITIES

Concurrent with the issue of 2017 Notes and 2018 Notes under the MMTN Program (Note 21), the Group entered into the following cross currency swaps with total notional contract amount of US$ 263.8 million:

a) Cross currency swaps of a similar duration to convert the 3-Year S$ fixed rate liability of S$130.0 million (2013: Nil) to US$ floating rate liability of US$103.3 million (2013: Nil);

b) Cross currency swaps of a similar duration to convert the 4-Year S$ fixed rate liability of S$200.0 million (2013: Nil) to US$ floating rate liability of US$160.5 million (2032: Nil);

Under the cross currency swaps, the Group agreed with the swap counterparties to exchange S$ for US$ at the start date of the swaps and vice versa at the maturity date. In addition, the Group will exchange US$ interest amounts for S$ interest amounts with the swap counterparties, at specified intervals during the tenor of the cross currency swaps, calculated by reference to the respective contracted notional principal amounts. The cumulative fair value changes of the risk hedged was included in the carrying value of the KEL Multi-currency Medium Term Note (Note 21). The cross currency swaps will mature between 2017 and 2018.

The decrease in fair value of the cross currency swaps of US$19,388,642 has been recognised in other operating expenses (Note 6) and offset with the gain due to hedge of US$16,428,196 that has been adjusted to the carrying amount of the 2017 and 2018 Notes.

GROUP AND COMPANY	FAIR VALUES			
	ASSETS		LIABILITIES	
	2014 US$	2013 US$	2014 US$	2013 US$
CURRENT				
Fair-value hedges				
• Cross currency swaps	–	–	19,388,642	–
	–	–	**19,388,642**	–

26 COMMITMENTS

(a) Operating lease commitments

The Group has entered into non-cancellable commercial property leases for the office operations. These operating leases have remaining lease terms of one year or more.

Future minimum lease payments payable under non-cancellable operating leases as at 31 December are as follows:

GROUP	2014 US$	2013 US$
Within one year	807,275	664,078
After one year but not more than five years	213,125	1,222,050
	1,020,400	**1,886,128**

(b) Capital commitments

Certain of our joint operations have firm capital commitments where we are required to participate in minimum exploration activities. The Group's share of the estimated minimum exploration commitments is approximately US$116,732,550 (2013: US$103,764,800).

At the reporting date, the Group's outstanding minimum exploration commitments will fall due as follows:

GROUP	2014 US$	2013 US$
Within one year	13,740,050	17,453,300
Within two to five years	102,992,500	86,311,500
	116,732,550	**103,764,800**

27 RELATED PARTY DISCLOSURES

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year was as follows:

GROUP	2014 US$	2013 US$
Salaries and bonus	10,892,157	9,439,231
Central Provident Fund Contributions	67,199	67,217
Share-based payments	1,561,676	367,596
	12,521,032	**9,874,044**
Comprise amounts paid to		
Directors of the Company	4,801,636	3,527,318
Other key management personnel	7,719,396	6,346,726
	12,521,032	**9,874,044**

28 FAIR VALUE OF FINANCIAL INSTRUMENTS

(a) Fair value hierarchy

The Group categorises fair value measurement using a fair value hierarchy that is dependent on the valuation inputs used as follows:

- Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date;
- Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices); and
- Level 3 – Unobservable inputs for the asset or liability.

Fair value measurements that use inputs of different hierarchy levels are categorised in its entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement.

(b) Assets and liabilities measured at fair value

The following table shows an analysis of assets and liabilities measured at fair value at the end of the reporting period:

GROUP	NOTE	LEVEL 1 US$	LEVEL 2 US$	LEVEL 3 US$	TOTAL US$
2014					
Financial liabilities:					
Derivative liabilities	25				
• Cross currency swaps		–	19,388,642	–	19,388,642
Loans and borrowings	21				
• Fair value of hedged risk of multi-currency medium term notes		–	(16,428,196)	–	(16,428,196)
		–	**2,960,446**	–	**2,960,446**
2013					
Financial assets:					
Embedded derivatives	12	–	6,137,226	–	6,137,226

COMPANY	NOTE	LEVEL 1 US$	LEVEL 2 US$	LEVEL 3 US$	TOTAL US$
2014					
Financial liabilities:					
Derivative liabilities	25				
• Cross currency swaps		–	19,388,642	–	19,388,642
Loans and borrowings	21				
• Fair value of hedged risk of multi-currency medium term notes		–	(16,428,196)	–	(16,428,196)
		–	**2,960,446**	–	**2,960,446**

(c) Level 2 fair value measurements

The following is a description of the valuation techniques and inputs used in the fair value measurement for assets that are categorised within Level 2 of the fair value hierarchy:

Cross currency swaps and hedged risk

Swap contracts and hedged risks are valued using a valuation technique with market observable inputs which includes forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, interest rate curves and forward rate curves.

Embedded derivatives

Fair value of embedded derivatives are valued using a valuation technique with market observable inputs. The trinomial tree lattice, i.e. Hull-White one factor Trinomial Tree ("Hull & White" model), is constructed to model the interest rates used to value the Bonds. The Hull & White Model incorporates various inputs including the short rate volatility, mean reversion and discount rate.

(d) Fair value of financial instruments by classes that are not carried at fair value and whose carrying amounts are not reasonable approximation of fair value

The fair value of financial assets and liabilities by classes that are not carried at fair value and whose carrying amounts are not reasonable approximation of fair value are as follows:

	CARRYING AMOUNT		FAIR VALUES	
	2014 US$	**2013** US$	**2014** US$	**2013** US$
Financial assets:				
Equity securities, at cost	–	182,057	–	*

* Investment in equity securities carried at cost

Fair value information has not been disclosed for the Group's investment in equity securities that are carried at cost because fair value cannot be measured reliably. These equity securities are not quoted on any market and does not have any comparable industry peer that is listed.

29 FINANCIAL RISK MANAGEMENT OBJECTIVES AND POLICIES

The Group is exposed to financial risks arising from its operations and the use of financial instruments. The key financial risks include credit risk, interest rate risk, and liquidity risk. It is, and has been throughout the current financial year, the Group's policy that no derivatives shall be undertaken, except for the use as hedging instruments where appropriate and cost-efficient.

The following sections provide details regarding the Group's exposure to the above-mentioned financial risks and the objectives, policies and processes for the management of these risks.

Credit risk

Credit risk is the risk of loss that may arise on outstanding financial instruments should a counterparty default on its obligations. The Group's exposure to credit risk arises primarily from trade and other receivables. For other financial assets (including cash and bank balances and derivatives), the Group minimises credit risk by dealing exclusively with high credit rating counterparties.

Exposure to credit risk

At the end of the reporting date, the Group's maximum exposure to credit risk is represented by:

- The carrying amount of each class of financial assets recognised in the consolidated statement of financial position;
- The carrying amount of loans and borrowings recognised in the consolidated statement of financial position and corporate guarantees.

Credit risk concentration profile

At the reporting date, approximately 23% (2013: 65%) of the Group's receivables arises from the Group's working interest in Glagah Kambuna TAC, B8/32 concession, B9A concession and Block 9 PSC.

Financial assets that are neither past due nor impaired

Trade and other receivables that are neither past due nor impaired are with creditworthy debtors with good payment record with the Group. Cash and cash equivalents, investment securities and derivatives are placed with or entered into with reputable financial institutions or companies with high credit ratings and no history of default.

Financial assets that are either past due or impaired

Information regarding financial assets that are either past due or impaired is disclosed in Note 16 (Trade and other receivables).

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of the Group's financial instrument will fluctuate because of changes in market interest rates. As at 31 December 2014 and 2013, the Group has insignificant financial instruments that are exposed to interest rate risk.

Liquidity risk

Liquidity risk is the risk that the Group will encounter difficulty in meeting financial obligations due to shortage of funds. The Group's exposure to liquidity risk arises primarily from mismatches of the maturities of financial assets and liabilities.

The table below summaries the maturity profile of the Group's financial assets and liabilities at the reporting date based on contractual undiscounted repayments obligations.

GROUP	ONE YEAR OR LESS US$	ONE TO FIVE YEARS US$	MORE THAN FIVE YEARS US$	TOTAL US$
2014				
Financial assets:				
Trade and other receivables	61,012,794	–	–	61,012,794
Cash and bank balances	51,334,088	–	–	51,334,088
Total undiscounted financial assets	112,346,882	–	–	112,346,882
Financial liabilities:				
Trade and other payables	27,393,025	–	–	27,393,025
Accrued operating expenses	20,191,470	–	–	20,191,470
Loans and borrowings	–	257,440,512	–	257,440,512
Employee benefit liability	–	1,483,647	–	1,483,647
Total undiscounted financial liabilities	47,584,495	258,924,159	–	306,508,654
Total net undiscounted financial assets/(liabilities)	**64,762,387**	**(258,924,159)**	**–**	**(194,161,772)**

GROUP	ONE YEAR OR LESS US$	ONE TO FIVE YEARS US$	MORE THAN FIVE YEARS US$	TOTAL US$
2013				
Financial assets:				
Trade and other receivables	54,149,712	–	–	54,149,712
Cash and bank balances	251,809,697	–	–	251,809,697
Total undiscounted financial assets	305,959,409	–	–	305,959,409
Financial liabilities:				
Trade and other payables	35,990,001	–	–	35,990,001
Accrued operating expenses	13,012,320	–	–	13,012,320
Loans and borrowings	127,348,262	–	–	127,348,262
Employee benefit liability	–	–	884,691	884,691
Total undiscounted financial liabilities	176,350,583	–	884,691	177,235,274
Total net undiscounted financial assets/(liabilities)	**129,608,826**	**–**	**(884,691)**	**128,724,135**

The table below shows the contractual expiry by maturity of the Company's contingent liabilities and commitments. The maximum amount of the corporate guarantee for the KEHCL Callable Bonds and KEAL Revolving Credit Facility (Note 21) is allocated to the earliest period in which the guarantee could be called.

GROUP	ONE YEAR OR LESS US$	ONE TO FIVE YEARS US$	MORE THAN FIVE YEARS US$	TOTAL US$
2014				
Corporate guarantees	11,000,000	7,500,000	770,000	19,270,000
2013				
Corporate guarantees	127,348,262	–	–	127,348,262

30 CAPITAL MANAGEMENT

Capital includes debt and equity items as disclosed in the table below.

The primary objective of the Group's capital management is to ensure that it maintains healthy capital ratios in order to support its business and maximise shareholder value.

The Group manages its capital structure and makes adjustments to it, in light of changes in economic conditions. To maintain or adjust the capital structure, the Group may adjust the dividend payment to shareholders, return capital to shareholders or issue new shares.

No changes were made in the objectives, policies or processes during the year ended 31 December 2014 and 31 December 2013.

The Group monitors capital using a gearing ratio, which is net debt divided by total capital plus net debt. The Group's policy is to keep the gearing ratio between 20% and 40%. The Group includes within net debts, trade and other payables, accrued operating expenses, loans and borrowings, and employee benefit liability less cash and cash equivalents. Capital includes equity attributable to the owners of the Company.

GROUP	NOTE	2014 US$	2013 US$
Trade and other payables	20	27,393,025	35,990,011
Accrued operating expenses	20	20,191,470	13,012,320
Loans and borrowings	21	257,440,512	119,141,003
Employee benefit liability	23	1,483,647	884,691
Less: cash and cash equivalents	17	(51,334,088)	(247,809,697)
Net debt/(cash) position		255,174,566	(78,781,672)
Equity attributable to the owners of the Company		418,966,993	466,832,805
Capital and net debt		**674,141,559**	**466,832,805**
Gearing ratio		38%	–

31 SEGMENT REPORTING

For management purposes, the Group operates in one business segment that is exploration and production of oil and gas in Asia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	REVENUE		NON-CURRENT ASSETS	
GROUP	**2014** US$	**2013** US$	**2014** US$	**2013** US$
Bangladesh	17,834,862	1,660,915	40,535,469	43,314,839
Cambodia	–	–	88,697,969	22,849,049
Indonesia	–	4,031,510	90,290,422	60,047,002
Thailand	57,070,367	63,357,978	371,022,089	220,365,116
Vietnam	–	–	40,020,407	38,171,923
	74,905,229	**69,050,403**	**630,566,356**	**384,747,929**

Non-current assets information presented above consists of exploration and evaluation assets, oil and gas properties and intangible assets as presented in the consolidated statement of financial position.

Information about major customers

The Group identifies a major customer as one who contributes to 10 per cent or more of the total revenue. As at 31 December 2014, revenue from four (2013: three) major customers contributed to 13%, 38%, 25% and 24% (2013: 19%, 60%, 13% and Nil) of the total revenue respectively.

32 SUBSEQUENT EVENTS

Acquisition of Premier Oil Sumatra (North) B.V.

On 12 January 2015, the Group has completed the acquisition of Premier Oil Sumatra (North) B.V., which holds 41.67% working interest in the Block A Aceh PSC. Block A Aceh is located onshore Sumatra in the semi-autonomous region of Aceh and covers an area of 1,803 sq km. The Group acquired 100% of the issued share capital of Premier Oil Sumatra (North) B.V. in exchange for a total after-tax consideration of US$50.5 million.

The provisional fair values of the identifiable assets and liabilities of Premier Oil Sumatra (North) B.V. as at the date of acquisition were not disclosed as the initial accounting for the acquisition is incomplete as at the date of the financial statements.

Increase in working interests held in Block 105 PSC and Block 120 PSC

On 13 February 2015, pursuant to the deed executed in relation to the default and subsequent withdrawal of Neon Energy, the Group has received the amended investment certificate issued by the Ministry of Industry and Trade of Vietnam, reflecting the revised working interest holding of Block 105 to 33.33% and Block 120 to 33.33%.

On 9 March 2015, the Group has executed a deed of assignment with Eni Vietnam B.V. to take over its 66.67% working interest in and operatorship of Block 105 PSC. As at date of the financial statements, this transfer is pending approval from the Ministry of Industry and Trade of Vietnam.

33 AUTHORISATION OF CONSOLIDATED FINANCIAL STATEMENTS FOR ISSUE

The consolidated financial statements for the year ended 31 December 2014 were authorised for issue in accordance with a resolution of the directors on 16 March 2015.

SHAREHOLDING STATISTICS

Total number of issued shares	:	1,047,963,898
Class of Shares	:	Ordinary Shares of US$0.00125 par value
Voting rights	:	1 vote per ordinary Share

ANALYSIS OF SHAREHOLDINGS AS AT 18 MARCH 2015:

SIZE OF SHAREHOLDINGS	NUMBER OF SHAREHOLDERS	%	NUMBER OF SHARES	%
1 – 99	6	0.38	111	0.00
100 – 1,000	124	7.75	120,908	0.01
1,001 – 10,000	840	52.53	5,266,088	0.50
10,001 – 1,000,000	613	38.34	37,728,255	3.60
1,000,001 & above	16	1.00	1,004,848,536	95.89
Total	**1,599**	**100.00**	**1,047,963,898**	**100.00**

TOP TWENTY SHAREHOLDERS AS AT 18 MARCH 2015:

NO.	NAME OF SHAREHOLDER	NUMBER OF SHARES	%
1.	Merrill Lynch (S) Pte Ltd	479,619,568	45.19
2.	BNP Paribas Nominees Singapore Pte Ltd	328,536,000	31.35
3.	Citibank Nominees Singapore Pte Ltd	53,394,744	5.10
4.	DBS Nominees Pte Ltd	33,640,365	3.21
5.	DBSN Services Pte Ltd	29,900,764	2.85
6.	Morgan Stanley Asia (S) Securities Pte Ltd	23,644,400	2.26
7.	BNP Paribas Securities Services	15,682,000	1.50
8.	HSBC (Singapore) Nominee Pte Ltd	14,655,265	1.40
9.	Raffles Nominees (Pte) Ltd	13,654,042	1.30
10.	United Overseas Bank Nominees Pte Ltd	7,784,800	0.74
11.	OCBC Securities Private Ltd	3,146,475	0.30
12.	Radtke Investments L.P.	1,615,008	0.15
13.	CIMB Securities (S) Pte Ltd	1,591,205	0.15
14.	Lee Yuen Shih	1,491,000	0.14
15.	Bank of Singapore Nominees Pte Ltd	1,338,000	0.13
16.	UOB Kay Hian Pte Ltd	1,154,900	0.11
17.	Waterworth Pte Ltd	1,000,000	0.10
18.	DBS Vickers Securities (S) Pte Ltd	920,000	0.09
19.	John Henry Thibodeaux	778,000	0.07
20.	Chik Chooi Wah	670,000	0.06
	Total	1,008,216,536	96.20

SUBSTANTIAL SHAREHOLDERS AS AT 18 MARCH 2015:

	HOLDINGS REGISTERED IN NAME OF SUBSTANTIAL SHAREHOLDERS OR NOMINEES		HOLDINGS IN WHICH SUBSTANTIAL SHAREHOLDERS ARE DEEMED TO HAVE AN INTEREST IN		TOTAL SHAREHOLDING	
	NO. OF SHARES	%	NO. OF SHARES	%	NO. OF SHARES	%
KrisEnergy Holdings Ltd	473,206,568	45.15	-	-	473,206,568	45.15
First Reserve Fund XII L.P.	-	-	473,206,568[1]	45.15	473,206,568	45.15
First Reserve GP XII, L.P.	-	-	473,206,568[1]	45.15	473,206,568	45.15
First Reserve GP XII Limited	-	-	473,206,568[1]	45.15	473,206,568	45.15
William Macaulay	-	-	473,206,568[1]	45.15	473,206,568	45.15
Devan International Limited	328,536,000	31.35	-	-	328,536,000	31.36
Keppel Oil & Gas Pte Ltd	-	-	328,536,000[2]	31.36	328,536,000	31.36
Kepventure Pte Ltd	-	-	328,536,000[2]	31.36	328,536,000	31.36
Keppel Corporation Limited	-	-	328,536,000[2]	31.36	328,536,000	31.36
Temasek Holdings (Private) Limited	-	-	328,536,000[3]	31.36	328,536,000	31.36

NOTES:

(1) First Reserve Fund XII L.P. ("FR XII"), First Reserve GP XII, L.P. ("FR GP XII"), First Reserve GP XII Limited ("FR GP XII Limited") and William Macaulay are deemed under Section 4 of the Securities and Futures Act, Chapter 289 of Singapore ("SFA") to have an interest in the Shares held by KrisEnergy Holdings Ltd. ("KEHL") as:

(a) FR XII is the holding company of KEHL;

(b) FR XII is managed by FR GP XII;

(c) FR GP XII is managed by FR GP XII Limited; and

(d) William Macaulay has the ability to appoint directors of FR GP XII Limited

(2) Keppel Oil and & Gas Pte Ltd. ("Keppel O&G"), Kepventure Pte Ltd ("KepVenture"), Keppel Corporation Limited ("Keppel Corp") are each deemed under Section 4 of the SFA to have an interest in the Shares held by Devan International Limited ("Devan") as:

(a) Devan is a wholly owned subsidiary of Keppel O&G;

(b) Keppel O&G is a wholly owned subsidiary of KepVenture; and

(c) KepVenture is a wholly owned subsidiary of Keppel Corp

(3) Temasek Holdings (Private) Limited ("Temasek") is deemed under Section 4 of the SFA to have an interest in the Shares held by Devan as:

(a) Devan is a wholly owned subsidiary of Keppel O&G;

(b) Keppel O&G is a wholly owned subsidiary of KepVenture;

(c) KepVenture is a wholly owned subsidiary of Keppel Corp; and

(d) Temasek has more than 20% interest in Keppel Corp, an independently managed Temasek portfolio company

Public Shareholders

Based on the information available to our Company as at 18 March 2015, approximately 22.81% of the issued shares of our Company is held by the public and therefore, pursuant to Rules 1207 and 723 of the Listing Manual of the Singapore Exchange Securities Trading Limited, it is confirmed that at least 10% of the ordinary shares of our Company is at all times held by the public.

Treasury Shares

As at 18 March 2015, the Company does not hold any treasury shares.

NSAI SUMMARY OF QUALIFIED PERSON'S REPORT

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST
J. CARTER HENSON, JR.
DAN PAUL SMITH
JOSEPH J. SPELLMAN

January 19, 2015

Board of Directors
KrisEnergy (Asia) Ltd
83 Clemenceau Avenue
10-05, UE Square, Shell House
Singapore 239920

Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2014, to the KrisEnergy (Asia) Ltd (referred to herein as "KrisEnergy") interest in certain oil and gas properties located in Blocks B8/32 and B9A, Wassana Field, and Nong Yao Field, offshore Thailand; Lengo Field, offshore Indonesia; and Bangora Field, onshore Bangladesh. Also as requested, we have estimated the development pending contingent resources and cash flow, as of December 31, 2014, to the KrisEnergy interest in certain discoveries located offshore Thailand, offshore and onshore Indonesia, and offshore Cambodia and the development unclarified contingent resources, as of December 31, 2014, to the KrisEnergy working interest in certain other discoveries located offshore Thailand, offshore and onshore Indonesia, offshore Cambodia, and onshore Bangladesh. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by KrisEnergy, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. The tables following the definitions set forth our estimates of reserves and contingent resources, by category, to the KrisEnergy interest for each asset area.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) reserves and working interest reserves and future net revenue to the KrisEnergy interest in these properties, as of December 31, 2014, to be:

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201-2737 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010-3034 • PH: 713-654-4950 • FAX: 713-654-4951
nsai@nsai-petro.com
netherlandsewell.com

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Category	Gross (100%) Reserves Oil (MBBL)	Gross (100%) Reserves Gas (MMCF)	Working Interest Reserves Oil (MBBL)	Working Interest Reserves Gas (MMCF)	Future Net Revenue[1] (M$) Total	Future Net Revenue[1] (M$) Present Worth At 10%
Proved Developed Producing	23,607.4	235,353.8	1,206.0	50,630.0	(26,505.0)	(6,014.3)
Proved Developed Non-Producing	451.3	17,275.0	20.9	800.6	5,960.3	4,978.3
Proved Undeveloped	15,364.1	82,392.5	2,483.0	11,932.3	79,401.6	59,111.4
Proved (1P)	39,422.8	335,021.3	3,709.9	63,362.9	58,856.9	58,075.4
Probable	111,112.5	1,086,682.5	18,664.7	228,150.5	710,999.0	441,186.1
Proved + Probable (2P)	150,535.3	1,421,703.8	22,374.6	291,513.4	769,855.8	499,261.5
Possible	37,648.9	258,111.0	10,383.7	41,161.2	296,938.2	201,336.8
Proved + Probable + Possible (3P)	188,184.2	1,679,814.7	32,758.4	332,674.7	1,066,794.0	700,598.4

Totals may not add because of rounding.

(1) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, and income taxes.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates of reserves shown in this report are for proved, probable, and possible reserves. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves is KrisEnergy's share of the gross (100 percent) revenue from the properties after deductions for royalties. Future net revenue is after additional deductions for KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, and income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the KrisEnergy interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on KrisEnergy receiving its net revenue interest share of estimated future gross production.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The discoveries assessed in this report have been subclassified as development pending or development unclarified. The 2007 PRMS defines a development pending discovery as a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future and a development unclarified discovery as a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The contingent resources shown in this report are contingent upon one or more of the

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following: (1) commitment of the license partners to develop the resources, (2) submission and approval of a Plan of Development, Production Area Application, or Production Permit Application, (3) completion of a gas sales agreement, and (4) collection of additional technical data, to be collected through delineation wells and flow tests, to establish commercial viability. The costs required to resolve these contingencies have not been included in this report; estimates of cash flow are based on the assumption that all applicable contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for the development unclarified contingent resources. Because of the early stage of development of these projects, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the gross (100 percent) contingent resources and working interest contingent resources and net contingent cash flow to the KrisEnergy interest in these discoveries, as of December 31, 2014, to be:

	Gross (100%) Contingent Resources		Working Interest Contingent Resources		Net Contingent Cash Flow[1] (M$)	
Subclassification/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Discounted At 10%
Development Pending						
Low Estimate (1C)	1,189.0	393,956.2	495.4	164,148.1	295,811.7	80,057.0
Best Estimate (2C)	23,912.5	520,840.7	12,726.2	228,448.5	661,062.8	246,922.6
High Estimate (3C)	45,648.6	590,099.3	22,371.7	265,136.6	1,055,181.5	468,571.8
Development Unclarified						
Low Estimate (1C)	3,690.0	746,234.4	1,453.6	309,277.7	[2]	[2]
Best Estimate (2C)	7,140.9	1,205,357.9	3,055.2	497,631.1	[2]	[2]
High Estimate (3C)	33,740.6	1,894,686.0	11,217.3	771,486.3	[2]	[2]

Note: Contingent resources are the arithmetic sum of multiple probability distributions.

(1) Net contingent cash flow is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, Aceh community development fund payments, Exxon Mobil Indonesia overriding royalty interest, and income taxes.

(2) Because of the early stage of development of these projects, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

The oil volumes shown include crude oil and condensate.

The contingent resources shown in this report have been estimated using probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk. As recommended in the PRMS, the 1C, 2C, and 3C contingent resources have been aggregated beyond the field level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Gross contingent revenue for the development pending discoveries is KrisEnergy's share of the gross (100 percent) revenue from the properties after deductions for royalties. Net contingent cash flow is after deductions for KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, Aceh community development fund payments, Exxon Mobil Indonesia overriding royalty interest, and income taxes. The net contingent cash flow has been discounted at an annual rate of 10 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

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ECONOMIC PARAMETERS

As requested, this report has been prepared using oil and gas price parameters specified by KrisEnergy. Oil prices for the reserves and development pending contingent resources are based on the 12-month unweighted arithmetic average daily oil price for each month in the period January through December 2014. The oil prices used are based on the average U.S. Energy Information Administration Brent spot price of $99.02 per barrel and are adjusted by field area for quality, transportation fees, and market differentials. Oil prices are held constant throughout the lives of the properties.

Gas prices for Block B8/32 and Block B9A reserves are based on the Tantawan Gas Sales Agreement price of $5.713 per MMBTU and are adjusted by field area for energy content. The gas price for Bangora Field reserves is the contract price of $2.319 per MCF. The gas prices for Block A Aceh are based on a contract price of $9.45 per MMBTU that is pending Aceh government approval and also an expected price of $9.00 per MMBTU for the surplus gas volumes; these prices are adjusted for energy content. Gas prices for Blocks B8/32, B9A, and A Aceh and Bangora Field are held constant throughout the lives of the properties.

The gas prices for Lengo, East Lengo, Dambus, and Mangkok Fields are based on recent gas contracts in similar areas and are $7.000 per MMBTU for Lengo and East Lengo Fields and $8.000 per MMBTU for Dambus and Mangkok Fields; these prices are adjusted for energy content. Gas prices for Lengo, East Lengo, Dambus, and Mangkok Fields are escalated 3 percent per year from the year of first production throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of and budgets prepared by the operators of the properties, as provided by KrisEnergy. These costs include the per-well overhead expenses allowed under concession agreements along with estimates of costs to be incurred at and below the field level. Headquarters general and administrative overhead expenses of KrisEnergy are included to the extent that they are covered under concession agreements for the operated properties. As requested, operating costs are not escalated for inflation.

Capital costs used in this report were provided by KrisEnergy and are based on budgeted expenditures and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are KrisEnergy's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves and development pending contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. Our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future

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production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. The contingent resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from KrisEnergy, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
Philip S. (Scott) Frost, P.E. 88738
Senior Vice President

Date Signed: January 19, 2015

PSF:TDL

STATE OF TEXAS
P. S. FROST
88738
LICENSED
PROFESSIONAL ENGINEER

By:
Allen E. Evans, Jr., P.G. 1286
Vice President

Date Signed: January 19, 2015

STATE OF TEXAS
A. E. EVANS
GEOLOGY
1286
LICENSED
PROFESSIONAL GEOSCIENTIST

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

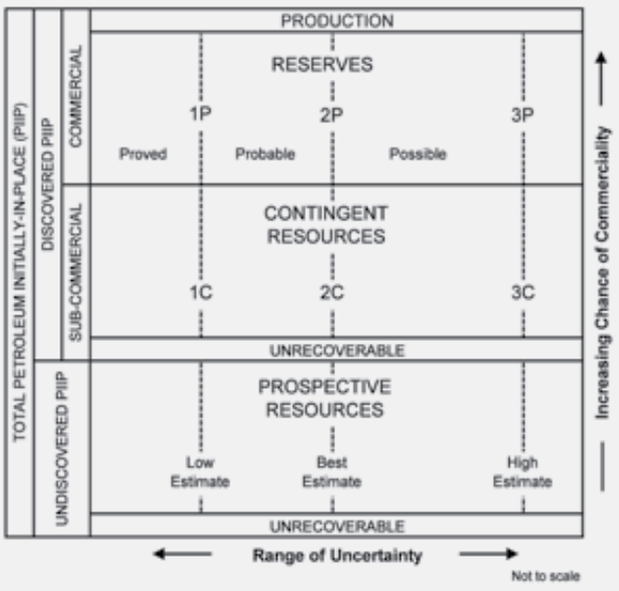


Figure 1-1: Resources Classification Framework.

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

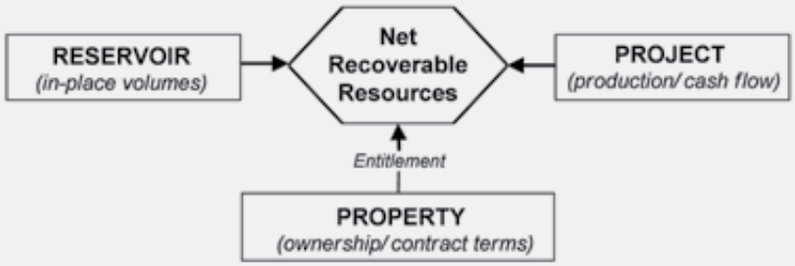


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

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Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	**Definition**	**Guidelines**
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	**Definition**	**Guidelines**
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are 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. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are 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 (2P). 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 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2014

Country/Asset/Category	Gross Reserves[1] Oil (MBBL)	Gross Reserves[1] Gas (MMCF)	Working Interest Reserves[2] Oil (MBBL)	Working Interest Reserves[2] Gas (MMCF)	Net Reserves[3] Oil (MBBL)	Net Reserves[3] Gas (MMCF)	Future Net Revenue[4] (M$) Total	Future Net Revenue[4] (M$) Present Worth at 10%
Offshore Thailand								
Blocks B8/32 and B9A								
Proved Developed Producing	23,166.1	78,753.1	1,073.6	3,649.8	975.6	3,414.2	(52,503.3)[5]	(27,646.5)[5]
Proved Developed Non-Producing	451.3	17,275.0	20.9	800.6	18.3	733.7	5,960.3	4,978.3
Proved Undeveloped	5,489.6	50,404.9	254.4	2,336.0	226.9	2,147.1	20,797.1	14,392.7
Proved (1P)	29,107.1	146,433.0	1,349.0	6,786.4	1,220.8	6,295.0	(25,745.9)[5]	(8,275.5)[5]
Probable	94,374.0	562,591.8	4,373.8	26,073.3	3,882.9	23,575.5	162,295.7	99,143.3
Proved + Probable (2P)	123,481.1	709,024.8	5,722.7	32,859.8	5,103.6	29,870.5	136,549.8	90,867.7
Possible	25,539.0	172,959.6	1,183.6	8,015.8	1,010.3	6,999.4	67,209.5	32,123.6
Proved + Probable + Possible (3P)	149,020.1	881,984.5	6,906.3	40,875.6	6,113.9	36,869.9	203,759.4	122,991.3
Block G10/48, Wassana Field								
Proved Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved (1P)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Probable	13,550.8	0.0	13,550.8	0.0	11,339.2	0.0	270,515.2	215,859.1
Proved + Probable (2P)	13,550.8	0.0	13,550.8	0.0	11,339.2	0.0	270,515.2	215,859.1
Possible	8,349.2	0.0	8,349.2	0.0	6,798.5	0.0	157,667.5	128,994.7
Proved + Probable + Possible (3P)	21,900.0	0.0	21,900.0	0.0	18,137.7	0.0	428,182.7	344,853.8
Block G11/48, Nong Yao Field								
Proved Undeveloped	9,783.1	0.0	2,201.2	0.0	2,057.2	0.0	50,886.3	40,068.1
Proved (1P)	9,783.1	0.0	2,201.2	0.0	2,057.2	0.0	50,886.3	40,068.1
Probable	2,883.1	0.0	648.7	0.0	604.3	0.0	22,566.3	16,474.0
Proved + Probable (2P)	12,666.2	0.0	2,849.9	0.0	2,661.5	0.0	73,452.6	56,542.1
Possible	3,696.6	0.0	831.7	0.0	775.8	0.0	24,259.0	16,168.8
Proved + Probable + Possible (3P)	16,362.8	0.0	3,681.6	0.0	3,437.3	0.0	97,711.7	72,711.0

Totals may not add because of rounding.

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

(1) Gross reserves correspond to the 100 percent interest or 8/8ths reserves.

(2) KrisEnergy's current working interest is 4.6345 percent in Blocks B8/32 and B9A, 100 percent in Wassana Field, 22.5 percent in Nong Yao Field, 42.5 percent in the Bulu PSC, and 30 percent in Bangora Field. It is anticipated that local participation will reduce the current working interest proportionately in Block G10/48 and Bulu PSC based on the local participant obtaining 10 percent. Where applicable, working interest reserves are estimated based on the current working interest and net revenue is estimated based on the future reduced working interest.

(3) Net reserves are the portion of gross reserves representing KrisEnergy's revenue entitlement.

(4) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, and income taxes.

(5) Future net revenue is negative after deducting estimated abandonment costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2014

Country/Asset/Category	Gross Reserves[1] Oil (MBBL)	Gross Reserves[1] Gas (MMCF)	Working Interest Reserves[2] Oil (MBBL)	Working Interest Reserves[2] Gas (MMCF)	Net Reserves[3] Oil (MBBL)	Net Reserves[3] Gas (MMCF)	Future Net Revenue[4] (M$) Total	Future Net Revenue[4] (M$) Present Worth at 10%
Offshore Indonesia								
Bulu PSC, Lengo Field								
Proved Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved (1P)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Probable	0.0	358,800.0	0.0	152,490.0	0.0	99,362.1	220,426.4	90,466.6
Proved + Probable (2P)	0.0	358,800.0	0.0	152,490.0	0.0	99,362.1	220,426.4	90,466.6
Possible	0.0	60,800.0	0.0	25,840.0	0.0	13,418.7	41,623.8	21,616.0
Proved + Probable + Possible (3P)	0.0	419,600.0	0.0	178,330.0	0.0	112,780.9	262,050.2	112,082.6
Onshore Bangladesh								
Block 9, Bangora Field								
Proved Developed Producing	441.3	156,600.7	132.4	46,980.2	49.6	25,045.6	25,998.2	21,632.2
Proved Undeveloped	91.4	31,987.6	27.4	9,596.3	14.2	6,368.6	7,718.1	4,650.6
Proved (1P)	532.6	188,588.3	159.8	56,576.5	63.7	31,414.1	33,716.4	26,282.9
Probable	304.6	165,290.7	91.4	49,587.2	26.4	22,147.1	35,195.4	19,243.1
Proved + Probable (2P)	837.2	353,879.0	251.2	106,163.7	90.1	53,561.2	68,911.8	45,526.0
Possible	64.1	24,351.3	19.2	7,305.4	4.0	3,165.3	6,178.2	2,433.7
Proved + Probable + Possible (3P)	901.3	378,230.3	270.4	113,469.1	94.2	56,726.5	75,090.0	47,959.7
Total								
Proved Developed Producing	23,607.4	235,353.8	1,206.0	50,630.0	1,025.2	28,459.8	(26,505.0)[5]	(6,014.3)[5]
Proved Developed Non-Producing	451.3	17,275.0	20.9	800.6	18.3	733.7	5,960.3	4,978.3
Proved Undeveloped	15,364.1	82,392.5	2,483.0	11,932.3	2,298.3	8,515.6	79,401.6	59,111.4
Proved (1P)	39,422.8	335,021.3	3,709.9	63,362.9	3,341.7	37,709.1	58,856.9	58,075.4
Probable	111,112.5	1,086,682.5	18,664.7	228,150.5	15,852.8	145,084.8	710,999.0	441,186.1
Proved + Probable (2P)	150,535.3	1,421,703.8	22,374.6	291,513.4	19,194.5	182,793.9	769,855.8	499,261.5
Possible	37,648.9	258,111.0	10,383.7	41,161.2	8,588.6	23,583.4	296,938.2	201,336.8
Proved + Probable + Possible (3P)	188,184.2	1,679,814.7	32,758.4	332,674.7	27,783.1	206,377.3	1,066,794.0	700,598.4

Totals may not add because of rounding.

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

(1) Gross reserves correspond to the 100 percent interest or 8/8ths reserves.

(2) KrisEnergy's current working interest is 4.6345 percent in Blocks B8/32 and B9A, 100 percent in Wassana Field, 22.5 percent in Nong Yao Field, 42.5 percent in the Bulu PSC, and 30 percent in Bangora Field. It is anticipated that local participation will reduce the current working interest proportionately in Block G10/48 and Bulu PSC based on the local participant obtaining 10 percent. Where applicable, working interest reserves are estimated based on the current working interest and net revenue is estimated based on the future reduced working interest.

(3) Net reserves are the portion of gross reserves representing KrisEnergy's revenue entitlement.

(4) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, and income taxes.

(5) Future net revenue is negative after deducting estimated abandonment costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF DEVELOPMENT PENDING
CONTINGENT RESOURCES AND CASH FLOW
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2014

	Gross Contingent Resources[1]		Working Interest Contingent Resources[2]		Net Contingent Resources[3]		Net Contingent Cash Flow[4] (M$)	
Country/Asset/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Discounted at 10%
Offshore Thailand								
Block G6/48, Rossukon Field								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	8,374.7	0.0	2,512.4	0.0	2,346.9	0.0	42,147.6	26,020.3
High Estimate (3C)	20,500.0	0.0	6,150.0	0.0	5,673.1	0.0	131,548.9	87,530.3
Block G10/48, Niramai Field								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	4,842.1	0.0	4,842.1	0.0	4,104.7	0.0	83,635.3	34,716.9
High Estimate (3C)	7,100.0	0.0	7,100.0	0.0	5,980.3	0.0	150,826.5	60,132.2
Offshore Indonesia								
East Muriah PSC, East Lengo Field								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	0.0	19,695.9	0.0	9,847.9	0.0	8,040.1	5,213.8	(1,957.9)[5]
High Estimate (3C)	0.0	48,865.1	0.0	24,432.6	0.0	16,707.5	31,308.8	8,541.4
Kutai PSC, Dambus and Mangkok Fields								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	90.1	75,700.0	49.2	41,332.2	39.8	26,465.0	100,095.1	43,630.5
High Estimate (3C)	146.8	117,449.0	80.2	64,127.1	64.9	36,991.3	152,179.9	64,009.1
Onshore Indonesia								
Block A Aceh								
Low Estimate (1C)	1,189.0	393,956.2	495.4	164,148.1	312.8	125,464.7	295,811.7	80,057.0
Best Estimate (2C)	2,068.5	425,444.8	861.9	177,268.4	490.0	131,835.5	334,522.0	94,732.6
High Estimate (3C)	2,949.1	423,785.2	1,228.8	176,576.9	682.8	129,619.5	347,624.1	103,808.8
Offshore Cambodia								
Block A, Platform A								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	8,537.1	0.0	4,460.6	0.0	3,503.7	0.0	95,449.1	49,780.2
High Estimate (3C)	14,952.7	0.0	7,812.8	0.0	5,556.8	0.0	241,693.4	144,550.0
Total[6]								
Low Estimate (1C)	1,189.0	393,956.2	495.4	164,148.1	312.8	125,464.7	295,811.7	80,057.0
Best Estimate (2C)	23,912.5	520,840.7	12,726.2	228,448.5	10,485.1	166,340.7	661,062.8	246,922.6
High Estimate (3C)	45,648.6	590,099.3	22,371.7	265,136.6	17,957.9	183,318.2	1,055,181.5	468,571.8

Totals may not add because of rounding.

(1) Gross contingent resources correspond to the 100 percent interest or 8/8ths resources.

(2) KrisEnergy's current working interest is 30 percent in Block G6/48, 100 percent in Block G10/48, 50 percent in the East Muriah PSC, 54.6 percent in the Kutai PSC, 41.6666 percent in Block A Aceh, and 52.25 percent in Block A. It is anticipated that local participation will reduce the current working interest proportionately in each asset based on the local participant obtaining 10 percent, except for Blocks G6/48, A Aceh and A. Where applicable, working interest contingent resources are estimated based on the current working interest and net contingent cash flows are estimated based on the future reduced working interest.

(3) Net contingent resources are the portion of gross resources representing KrisEnergy's cash flow entitlement.

(4) Net contingent cash flow is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried interests and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, Aceh community development fund payments, Exxon Mobil Indonesia overriding royalty interest, and income taxes.

(5) Future discounted net contingent cash flow is negative after deducting estimated abandonment costs.

(6) Totals are the arithmetic sum of multiple asset-level probability distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF DEVELOPMENT UNCLARIFIED
CONTINGENT RESOURCES
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2014

	Gross Contingent Resources[1]		Working Interest Contingent Resources[2]	
Country/Asset/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Offshore Thailand				
Block G10/48, Mayura Field				
Low Estimate (1C)	453.7	0.0	453.7	0.0
Best Estimate (2C)	1,140.3	0.0	1,140.3	0.0
High Estimate (3C)	3,124.7	0.0	3,124.7	0.0
Block G11/48, Angun Field				
Low Estimate (1C)	285.1	0.0	64.1	0.0
Best Estimate (2C)	663.8	0.0	149.4	0.0
High Estimate (3C)	21,066.8	0.0	4,740.0	0.0
Block G11/48, Mantana Field				
Low Estimate (1C)	0.0	4,922.7	0.0	1,107.6
Best Estimate (2C)	0.0	14,842.6	0.0	3,339.6
High Estimate (3C)	0.0	26,077.9	0.0	5,867.5
Block G11/48, Nong Yao Field				
Low Estimate (1C)	2,020.6	0.0	454.6	0.0
Best Estimate (2C)	3,281.2	0.0	738.3	0.0
High Estimate (3C)	4,665.2	0.0	1,049.7	0.0
Offshore Indonesia				
Tanjung Aru PSC, Halimun and Papandayan Fields				
Low Estimate (1C)	0.0	0.0	0.0	0.0
Best Estimate (2C)	0.0	110,510.4	0.0	47,519.5
High Estimate (3C)	0.0	155,810.7	0.0	66,998.6
Onshore Indonesia				
Block A Aceh				
Low Estimate (1C)	0.0	735,232.1	0.0	306,346.2
Best Estimate (2C)	202.9	1,052,325.6	84.6	438,468.3
High Estimate (3C)	1,213.7	1,583,845.3	505.7	659,934.5
Offshore Cambodia				
Block A, Platform B				
Low Estimate (1C)	762.1	0.0	398.2	0.0
Best Estimate (2C)	1,423.8	0.0	743.9	0.0
High Estimate (3C)	2,476.6	0.0	1,294.0	0.0
Block A, Platform C				
Low Estimate (1C)	145.6	0.0	76.1	0.0
Best Estimate (2C)	314.9	0.0	164.5	0.0
High Estimate (3C)	652.0	0.0	340.7	0.0
Onshore Bangladesh				
Block 9, Lalmai Field				
Low Estimate (1C)	23.0	6,079.6	6.9	1,823.9
Best Estimate (2C)	113.9	27,679.3	34.2	8,303.8
High Estimate (3C)	541.5	128,952.1	162.4	38,685.6
Total[3]				
Low Estimate (1C)	3,690.0	746,234.4	1,453.6	309,277.7
Best Estimate (2C)	7,140.9	1,205,357.9	3,055.2	497,631.1
High Estimate (3C)	33,740.6	1,894,686.0	11,217.3	771,486.3

Totals may not add because of rounding.

(1) Gross contingent resources correspond to the 100 percent interest or 8/8ths resources.

(2) KrisEnergy's current working interest is 100 percent in Block G10/48, 22.5 percent in Block G11/48, 43 percent in the Tanjung Aru PSC, 41.6666 percent in Block A Aceh, 52.25 percent in Block A, and 30 percent in Block 9. It is anticipated that local participation will reduce the current working interest proportionately in Block G10/48 and Tanjung Aru PSC based on the local participant obtaining 10 percent. Working interest contingent resources are estimated based on the current working interest.

(3) Totals are the arithmetic sum of multiple asset-level probability distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NOTICE OF ANNUAL GENERAL MEETING

The initial public offering of KrisEnergy Ltd. was sponsored by CLSA Singapore Pte Ltd and Merrill Lynch (Singapore) Pte. Ltd. (the "Joint Issue Managers, Global Coordinators, Bookrunners and Underwriters"). The Joint Issue Managers, Global Coordinators, Bookrunners and Underwriters assume no responsibility for the contents of this Notice.

KrisEnergy Ltd.
Company Registration Number: 231666
Incorporated in the Cayman Islands on 5 October 2009

NOTICE IS HEREBY GIVEN that the Second Annual General Meeting of KRISENERGY LTD. (the "Company") will be held at Grand Ballroom 2, Level 4, Grand Copthorne Waterfront Hotel, 392 Havelock Road, Singapore 169663, on 23 April 2015 at 10.00 a.m. to transact the following business (the "Annual General Meeting"):

A	ORDINARY SHARES	ORDINARY RESOLUTION
1.	To receive and adopt the Directors' Report and the Audited Financial Statements for the financial year ended 31 December 2014 and the Auditor's Report thereon.	Resolution 1
2.	To re-elect Mr. Christopher Gibson-Robinson, a Director retiring pursuant to Article 125 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory Note 1.]	Resolution 2
3.	To re-elect Mr. John William Gervase Honeybourne, a Director retiring pursuant to Article 125 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory Note 1.]	Resolution 3
4.	To re-elect Mr. Jeffrey Saunders MacDonald, a Director retiring pursuant to Article 125 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory Note 1.]	Resolution 4
5.	To re-elect Mr. Alan Rupert Nisbet, a Director retiring pursuant to Article 124 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory Note 1.]	Resolution 5
6.	To re-elect Mr. Keith James Pringle, a Director retiring pursuant to Article 124 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory Note 1.]	Resolution 6
7.	To approve the sum of US$1,153,458.90 (S$1,499,496.57) to be paid to all non-executive directors as Directors' fees for the financial year ended 31 December 2014. (2013: US$695,000 (S$870,377)) [See Explanatory Note 2.]	Resolution 7
8.	To re-appoint Ernst & Young LLP as Auditors of the Company and to authorise the Directors to fix their remuneration.	Resolution 8

B	SPECIAL BUSINESS	ORDINARY RESOLUTION

To consider and, if thought fit, to pass the following resolution as Ordinary Resolution, with or without modifications:

9. That pursuant to Rule 806 of the Listing Manual of the Singapore Exchange Securities Trading Limited ("SGX-ST"), authority be and is hereby given to the Directors of the Company to: — Resolution 9

(1) (i) issue shares in the capital of the Company (the "Shares") (whether by way of rights, bonus or otherwise); and/or
(ii) make or grant offers, agreements or options that might or would require Shares to be issued, including but not limited to the creation and issue of (as well as adjustments to) warrants, debentures or other instruments convertible into Shares (collectively, "Instruments"),
at any time and upon such terms and conditions and for such purposes and to such person(s) as the Directors may in their absolute discretion deem fit; and

(2) (notwithstanding the authority conferred by this Resolution may have ceased to be in force) issue shares in pursuance of any Instrument made or granted by the Directors while this Resolution was in force, provided that:
(a) the aggregate number of Shares to be issued pursuant to this Resolution (including new Shares to be issued in pursuance of Instruments made or granted pursuant to this Resolution) shall not exceed 50.0 per cent. of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below), of which the aggregate number of Shares to be issued other than on a pro rata basis to the shareholders of the Company (including new Shares to be issued in pursuance of Instruments made or granted pursuant to this Resolution) shall not exceed 20.0 per cent. of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below);
(b) (subject to such manner of calculation as may be prescribed by the SGX-ST) for the purpose of determining the aggregate number of Shares that may be issued under paragraph (a) above, the percentage of issued share capital shall be based on the issued share capital of the Company excluding treasury shares at the time this Resolution is passed, after adjusting for:
(i) new Shares arising from the conversion or exercise of any convertible securities or share options or vesting of share awards which are outstanding or subsisting at the time this Resolution is passed; and
(ii) any subsequent bonus issue, consolidation or subdivision of Shares;
(c) in exercising the authority conferred by this Resolution, the Company shall comply with the provisions of the Listing Manual of the SGX-ST for the time being in force (unless such compliance has been waived by the SGX-ST) and the Articles of Association for the time being of the Company; and
(d) (unless revoked or varied by the Company in general meeting) the authority conferred by this Resolution shall continue in force until the conclusion of the next annual general meeting of the Company or the date by which the next annual general meeting of the Company is required by law to be held, whichever is earlier.

[See Explanatory Note 3.]

10. To transact any other business as may properly be transacted at an annual general meeting.

By Order of the Board

KELVIN TANG / JENNIFER LEE
Joint Company Secretaries
8 April 2015, Singapore

NOTICE OF ANNUAL GENERAL MEETING

NOTES:

1. **Poll.** The Chairman of the Annual General Meeting will be exercising his right under Article 86(a) of the Memorandum and Articles of Association of the Company (the "Articles") to demand a poll in respect of the resolutions to be put to the vote at the Annual General Meeting and at any adjournment thereof. Accordingly, the Ordinary Resolutions proposed at the Annual General Meeting will be voted on by way of a poll.
2. **Depositors.** Under the Articles, unless The Central Depository (Pte) Limited ("CDP") specifies otherwise in a written notice to the Company, CDP is deemed to have appointed as CDP's proxies to vote on behalf of CDP at the Annual General Meeting each of the persons (who are individuals) holding shares in the capital of the Company through CDP and whose shares are entered in the Depository Register (as defined in Section 130A of the Companies Act, Chapter 50 of Singapore) ("Depositors"), whose names are shown in the records of CDP as at a time not earlier than 48 hours prior to the time of the Annual General Meeting supplied by CDP to the Company, and such appointment of proxies shall not require an instrument of proxy or the lodgement of any instrument of proxy.
   A Depositor may appoint not more than two persons (who shall be natural persons) to attend and vote in his place as proxy or proxies for CDP in respect of his shareholding, by completing and submitting the Depositor Proxy Form. The submission of a Depositor Proxy Form shall not preclude a Depositor appointed as a proxy by virtue of the Articles from attending and voting at the Annual General Meeting but in the event of attendance by such Depositor, the Depositor Proxy Form submitted bearing his name as the Nominating Depositor (as defined in the Articles) shall be deemed to be revoked. The Company will reject a Depositor Proxy Form if the Nominating Depositor's name is not shown in the records of CDP as at a time not earlier than 48 hours prior to the time of the Annual General Meeting supplied by CDP to the Company.
   Where a Depositor is a corporation and wishes to be represented at the Annual General Meeting, it must appoint a person or persons (who shall be natural persons) to attend and vote as proxy or proxies of CDP at the Annual General Meeting in respect of its shareholding, by completing and submitting the Depositor Proxy Form.
3. **Shareholders.** The Directors have fixed 21 April 2015 as the record date for determining those shareholders who are entitled to attend and vote at the Annual General Meeting. A shareholder of the Company (other than CDP) entitled to attend and vote at the Annual General Meeting who is the holder of two or more shares is entitled to appoint not more than two proxies to attend and vote instead of him, by completing and submitting the Shareholder Proxy Form.
   A proxy need not be a shareholder of the Company. Delivery of the Shareholder Proxy Form shall not preclude a shareholder from attending and voting in person at the Annual General Meeting and in such event, the Shareholder Proxy Form shall be deemed to be revoked.
4. **Deposit of Instrument of Proxy.** The instrument appointing a proxy or proxies (together with the power of attorney, if any, under which it is signed or a certified copy thereof) must be deposited at the office of M & C Services Private Limited at 112 Robinson Road #05-01, Singapore 068902 at least 48 hours before the time appointed for holding the Annual General Meeting.
5. **Personal Data Privacy.** By submitting an instrument appointing a proxy(ies) and/or representative(s) to attend, speak and vote at the Annual General Meeting and/or any adjournment thereof, a shareholder of the Company or, as the case may be, a Depositor (i) consents to the collection, use and disclosure of the shareholder's or, as the case may be, the Depositor's personal data by the Company (or its agents or service providers) for the purpose of the processing, administration and analysis by the Company (or its agents or service providers) of proxies and representatives appointed for the Annual General Meeting (including any adjournment thereof) and the preparation and compilation of the attendance lists, minutes and other documents relating to the Annual General Meeting (including any adjournment thereof), and in order for the Company (or its agents or service providers) to comply with any applicable laws, listing rules, regulations and/or guidelines (collectively, the "Purposes"), (ii) warrants that where the shareholder or, as the case may be, the Depositor discloses the personal data of the shareholder's or, as the case may be, the Depositor's proxy(ies) and/or representative(s) to the Company (or its agents or service providers), the shareholder or, as the case may be, the Depositor has obtained the prior consent of such proxy(ies) and/or representative(s) for the collection, use and disclosure by the Company (or its agents or service providers) of the personal data of such proxy(ies) and/or representative(s) for the Purposes, and (iii) agrees that the shareholder or, as the case may be, the Depositor will indemnify the Company in respect of any penalties, liabilities, claims, demands, losses and damages as a result of the shareholder's or, as the case may be, the Depositor's breach of warranty.

EXPLANATORY NOTES:

Resolutions 2 to 6

1. Detailed information on these Directors can be found in the section *Board of Directors* of the Company's Annual Report.
   (a) Mr. Christopher Gibson-Robinson is considered non-independent and is an executive Director.
   (b) Mr. John William Gervase Honeybourne, upon re-election as a Director of the Company, will remain as a member of the Nominating Committee. He is a nominee Director appointed by our indirect controlling shareholder, First Reserve Management L.P. and its affiliated funds. He is considered non-independent and is a non-executive Chairman and Director.
   (c) Mr. Jeffrey Saunders MacDonald, upon re-election as a Director of the Company, will remain as the Chairman of the Remuneration Committee and a member of the Nominating Committee and is considered independent.
   (d) Mr. Alan Rupert Nisbet was appointed to the Board on 13 May 2014. Upon re-election as a Director of the Company, he will remain as a member of the Audit Committee and the Remuneration Committee, and is considered independent.
   (e) Mr. Keith James Pringle was appointed to the Board on 13 May 2014. Upon re-election as a Director of the Company, he will remain as a member of the Audit Committee and the Remuneration Committee, and is considered independent.

Resolution 7

2. USD to SGD exchange rates of 1.30:1 and 1.25:1 were used for the financial years ended 31 December 2014 and 31 December 2013, respectively.

Resolution 9

3. Resolution 9 is to empower the Directors to issue shares in the capital of the Company and/or to make or grant Instruments (as defined in Resolution 9). The aggregate number of Shares which may be issued pursuant to Resolution 9 (including new Shares to be issued in pursuance of Instruments made or granted pursuant to Resolution 9) shall not exceed 50.0 per cent. of the issued share capital of the Company excluding treasury shares, with a sub-limit of 20.0 per cent. for Shares issued other than on a *pro rata* basis to Shareholders. For the purpose of determining the aggregate number of Shares that may be issued, the percentage of issued Shares shall be based on the total number of issued Shares in the capital of the Company excluding treasury shares at the time of the passing of Resolution 9, after adjusting for (i) new Shares arising from the conversion or exercise of any convertible securities or share options or vesting of share awards which are outstanding or subsisting at the time Resolution 9 is passed; and (ii) any subsequent bonus issue, consolidation or subdivision of Shares.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Will Honeybourne
Non-Executive Chairman
John Koh
Lead Non-Executive Independent Director
Keith Cameron
Executive Director and Chief Executive Officer
Chris Gibson-Robinson
Executive Director
Richard Lorentz
Executive Director
Brooks Shughart
Non-Executive Director
Choo Chiau Beng
Non-Executive Director
Loh Chin Hua
Non-Executive Director
Duane Radtke
Non-Executive Independent Director
Jeff MacDonald
Non-Executive Independent Director
Tan Ek Kia
Non-Executive Independent Director
Alan Nisbet
Non-Executive Independent Director
Keith Pringle
Non-Executive Independent Director

AUDIT COMMITTEE

John Koh
Chairman
Tan Ek Kia
Choo Chiau Beng
Brooks Shughart
Alan Nisbet
Keith Pringle

NOMINATING COMMITTEE

Tan Ek Kia
Chairman
John Koh
Duane Radtke
Jeff MacDonald
Will Honeybourne
Choo Chiau Beng

REMUNERATION COMMITTEE

Jeff MacDonald
Chairman
Duane Radtke
Brooks Shughart
Loh Chin Hua
Alan Nisbet
Keith Pringle

JOINT COMPANY SECRETARIES

Kelvin Tang
Jennifer Lee

REGISTERED OFFICE

Intertrust Corporate Services (Cayman) Limited
190 Elgin Avenue
George Town
Grand Cayman
KY1-9005
Cayman Islands
T: +1 345 943 3100
F: +1 345 945 4757

REGISTERED OFFICE IN SINGAPORE

83 Clemenceau Avenue
#10-05 UE Square
Singapore 239920
T: +65 6838 5430
F: +65 6538 3622

SHARE TRANSFER AGENT

M&C Services Private Limited
112 Robinson Road,
#05-01
Singapore 068902

AUDITORS

Ernst & Young LLP
Public Accountants and Chartered Accountants
One Raffles Quay
North Tower, Level 18
Singapore 048583

AUDIT PARTNER

Toong Weng Sum, Vincent
Year appointed: 2011
Singapore 048583

GLOSSARY

This glossary contains explanations and definitions of certain terms used in connection with our business. The assigned meaning may not correspond to standard industry or common meaning or usage of these terms.

1C
Low estimate scenario of contingent resources.

1P
Equivalent to proved reserves; denotes low estimate scenario of reserves.

2012 Code
Code of Corporate Governance 2012.

2014 RCF
US$100 million revolving credit facility.

2016 Notes
Senior guaranteed secured bonds due July 2016.

2017 Notes
Senior three-year fixed-rate notes due January 2017.

2018 Notes
Senior four-year fixed-rate notes due August 2018.

2C
Best estimate scenario of contingent resources.

2D seismic data
Geophysical data that depicts the subsurface strata in two dimensions (2D).

2P
Equivalent to proved plus probable reserves; denotes best estimate scenario of reserves.

3C
High estimate scenario of contingent resources.

3D seismic data
Geophysical data that depicts the subsurface strata in three dimensions (3D). 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic.

3P
Equivalent to proved plus probable plus possible reserves; denotes high estimate scenario of reserves.

AFE
Authority for expenditures.

AGM
Annual General Meeting.

Articles
Articles of Association.

bbl
Barrel.

bcf
Billion cubic feet.

BILD
Bangora Initiative Livelihood Development.

Block 105
Block 105-110/04.

boe
Barrel(s) of oil equivalent.

boepd
Barrel(s) of oil equivalent per day.

bopd
Barrel(s) of oil per day.

CALM buoy
Catenary anchor leg mooring buoy.

CEO
Chief Executive Officer.

CFO
Chief Financial Officer.

CLC
Community Learning Centres.

contingent resources
Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but are not currently considered to be commercially recoverable due to one or more contingencies.

COPCL
Chevron Overseas Petroleum (Cambodia) Ltd.

CSR
Corporate Social Responsibility.

CST
Centistoke.

DDA
Depreciation, depletion and amortisation.

development pending
The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing a basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable timeframe. Disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status.

development unclarified
A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual

commercial development, but further appraisal/evaluation are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal and/or evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to significant time delay.

DMO
Domestic market obligations.

E&P
Exploration and production.

EBITDAX
Earnings before interest, taxation, depreciation, amortisation, geological and geophysical expenses and exploration expenses.

EHSMS
Environment, Health and Safety Management System.

EHSS
Environment, Health, Safety & Security.

Eni
Eni S.p.A and/or its subsidiaries.

Executive Director
A Director of our Group who performs an executive function.

FID
Final investment decision.

First Reserve
First Reserve Management L.P., together with its affiliated funds.

Framework
Board Assurance Framework.

FOB
Free-on-Board.

FTP
First Tranche Petroleum.

FSO
Floating storage and offshore loading vessel.

IPO
Initial public offering.

JSA
Joint Study Agreement.

KrisEnergy ESOS
KrisEnergy Employee Share Option Scheme.

KrisEnergy PSP
KrisEnergy Performance Share Plan.

km
Kilometre.

mcf
Thousand cubic feet.

MD
Measured depth.

mm
million.

mmbo
Million barrels of oil.

mmboe
Million barrels of oil equivalent.

mmbtu
Million British thermal units.

mmcf
Million cubic feet.

mmcfd
Million cubic feet per day.

MME
Ministry of Mines and Energy in Cambodia.

MS-Awards
Shares awarded under the KrisEnergy PSP to certain Senior Management personnel on 19 July 2013 comprising 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied, subject to certain performance conditions being met and other terms and conditions.

MOPU
Mobile offshore production unit.

Mubadala
Mubadala Development Corporation and/or its subsidiaries.

MTN Program
Medium-Term Note Program.

NSAI
Netherland, Sewell & Associates, Inc.

Northern Gulf Petroleum
Northern Gulf Petroleum Pte Ltd and/or its subsidiaries.

PAA
Production Area Application.

Palang Sophon
Palang Sophon Ltd and/or its subsidiaries.

POD
Plan of development.

possible reserves
Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves.

probable reserves
Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than proved reserves but more certain to be recovered than possible reserves.

prospective resources
Those quantities of petroleum, which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

proved reserves
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.

PSC
Production sharing contract, which is an agreement with the relevant host government, which outlines the fiscal terms for exploring, developing and producing oil and gas within a specified contract area.

QPR
Qualified person's report.

RCF
Revolving credit facility.

Senior Management
Executive Directors, the CEO and other key management personnel.

SGX-ST
Singapore Exchange Securities Trading Ltd.

sq. km
Square kilometre.

TAC
Technical Assistance Contract.

tcf
Trillion cubic feet.

Tullow Bangladesh
Tullow Bangladesh Ltd.

TVDSS
Total vertical depth subsea.

working interest
Percentage ownership in a joint operation associated with revenue and costs. Working interests do not take into account the terms of any royalties, government shares of production, or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.

KRISENERGY REGIONAL OFFICES

BANGLADESH
NB Tower, Level 12
40/7, North Avenue
Gulshan 2, Dhaka 1212

CAMBODIA
No. 28, Street 310
Sangkat Boeung, Keng Kang 1
Khan Chamcar Monn
Phnom Penh, P.O. Box 1619

INDONESIA
Talavera Office Park
3rd Floor, Jln. Let. Jend. TB.
Simatupang, Kav. 22-26
Cilandak
Jakarta 12430

SINGAPORE
83 Clemenceau Avenue
#10-05, UE Square
Singapore 239920

THAILAND
7F, Athenee Tower
No. 63, Wireless Road
Lumpini, Pathumwan
Bangkok 10330

VIETNAM
19F, Bitexco Financial Tower
No. 2, Hai Trieu Street, Dist. 1
Ho Chi Minh City

Designed by Charles Allan Associates Pte Ltd

www.krisenergy.com

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