Gaffney,
Cline &
Associates

# Qualified Person's Report for the Edvard Grieg South Discovery, Norway

Prepared for

## Lime Petroleum Norway AS

**10th March, 2017**

Gaffney, Cline & Associates

## Document Approval and Distribution

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10th March, 2017

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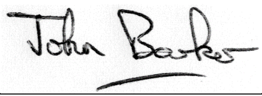

10th March, 2017

Dr. John Barker – Technical Director, Reservoir Engineering

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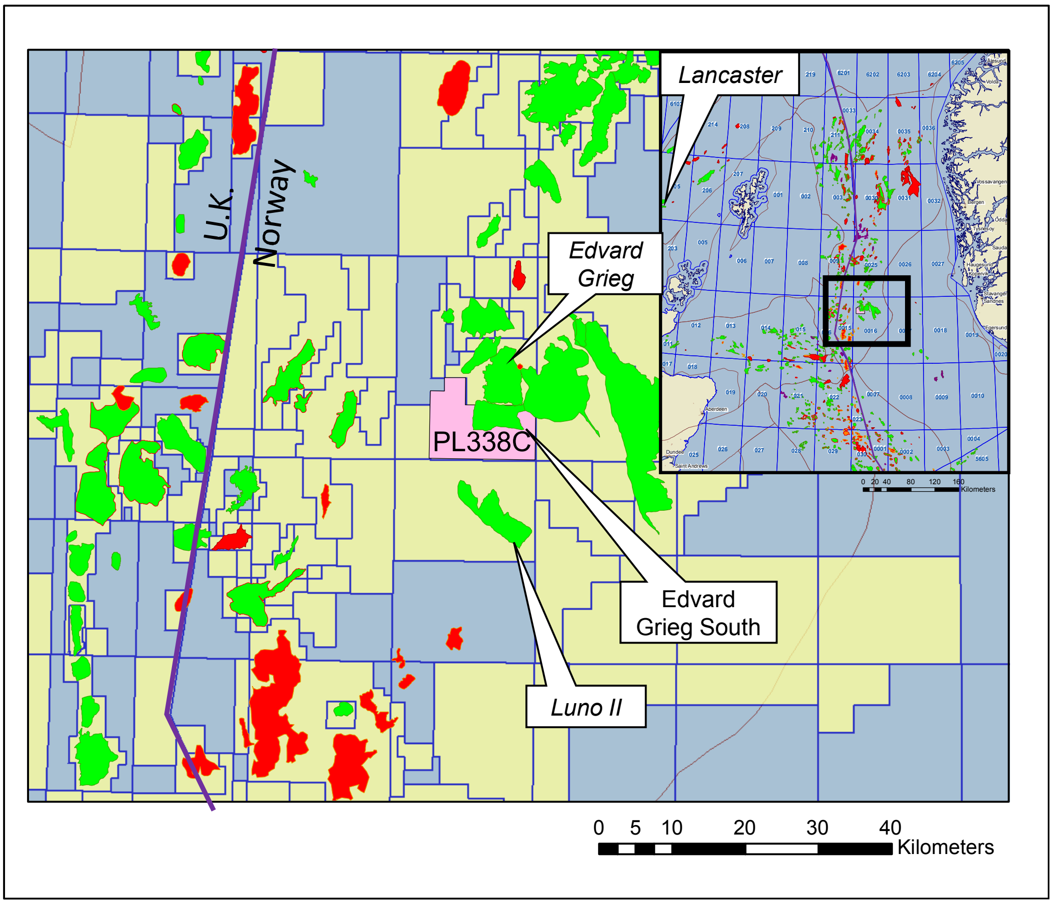
# 1 Introduction

## 1.1 Overview

At the request of Lime Petroleum Norway AS (Lime or "the Client"), Gaffney, Cline & Associates (GCA) of Bentley Hall, Bentley, United Kingdom has prepared a Qualified Person's Report (QPR) of the Contingent Resources of the Edvard Grieg South Discovery, located offshore Norway (Figure 1).

At the date of this report, Lime shareholders are Rex International Investments Pte. Ltd. (87.8% equity), a wholly owned subsidiary of Rex International Holding Limited (Rex), Schroder & Co Banque SA (10% equity), and Lime Petroleum Plc (2.2% equity), a jointly controlled entity in which Rex International Holding Limited has 65% indirect ownership and Hibiscus Petroleum Berhad with 35% indirect ownership.

**Figure 1: Edvard Grieg South Discovery Location Map**




Source: Wood Mackenzie Petroview

The Edvard Grieg South Discovery lies in PL338C, which is operated by Lundin Petroleum AB (Lundin), holders of a 50% working interest in the license. Lime holds a 30% working interest and OMV (Norge) AS the remaining 20%.

PL338C covers an area of 121.637 $km^2$ and is in the initial exploration phase, the license having been granted in December 2014 and being valid until mid-December 2019. The license lies immediately south of the Edvard Grieg field and some 10 km north of the Luno II discovery.

Lundin also refers to the Edvard Grieg South Discovery as the Rolvsnes Discovery, and GCA understands that the ultimate name is still being finalized by the partners. The Discovery comprises light oil in a fractured and weathered granite basement reservoir on the Utsira High geological structure.

A conference call was held between GCA and Lime on 24th January, 2017, where some data and the current status of the technical work in the PL338C license were discussed. Some further data were provided subsequently by Lime after being requested from Lundin. GCA also held a conference call with Lime and Lundin on 2nd February, 2017 to further discuss the data.

### 1.1.1 Aim of Report

The aim of this report is to provide Lime with a QPR document, as required for regulatory reporting, that provides an independent assessment of the hydrocarbon resources for the Edvard Grieg South discovery.

This QPR complies with the requirements as set out in Practice Note 4C, Disclosure Requirements for Mineral, Oil and Gas Companies (Effective from 27th September, 2013) as issued by the Singapore Exchange Securities Trading Limited (SGX) under the SGX Listing Manual, Section B, Rules of Catalist (Listing Rules).

### 1.1.2 Use of the Report

This report relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

Lime will obtain GCA’s prior written or email approval for the use by third parties of any reports, results, statements or opinions attributed to GCA, including the form and context in which they are intended to be used. Such requirement of approval shall include, but not be confined to, statements or references in documents of a public or semi-public nature such as loan agreements, prospectuses, reserve statements, websites, press releases, etc. Lime also acknowledges GCA's copyright in all manuals and/or other training materials which may be provided under the Work.

## 1.2 Basis of Opinion

This document reflects GCA’s informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief, that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GCA has used definitions contained within the Petroleum Resources Management System (PRMS) Standard, which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in March 2007 (see Appendix I).

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognised as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes are reported in millions ($10^6$) of barrels at stock tank conditions (MMBbl). Standard conditions are defined as 14.7 psia and 60°F. Industry Standard terms and abbreviations are contained in the attached Glossary (Appendix II), some or all of which may have been used in this report.

GCA prepared an independent assessment of the resources based on data and interpretations provided by the Client.

**Definition of Resources**

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 because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident 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 categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development" (per PRMS).

GCA has not undertaken a site visit and inspection because the asset is offshore and there are no production facilities yet in place. As such, GCA is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GCA is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

**Qualifications**

GCA is an independent international energy advisory group of more than 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with the Client. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

**Mr. Drew Powell**, Global Director, Operations, has 27 years' industry experience and holds a B.Eng in Chemical Engineering from the University of Aston in Birmingham. He holds a Fellowship from the Institution of Chemicals Engineers and is a Chartered Engineer through the UK Engineering Council. He is a member of the Society of Petroleum Engineers and of the Energy Institute.

**Dr. John Barker**, Technical Director, Reservoir Engineering, has 32 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

**Ms. French** holds an M.A. in Earth Sciences and a Diploma in Petroleum Geochemistry and has 18 years' industry experience. She is a member of the Geological Society and of the Society of Petroleum Engineers.

**Mr. Makhonin** holds an M.Sc. in Geology and is a petrophysicist with 14 years' industry experience.

**Qualified Person**

The QPR was prepared by GCA staff under the supervision of Mr. Drew Powell (GCA Operations Director), aided by Ms. Abby French and Mr. Alexey Makhonin. The final report was approved at the corporate level by Dr. John Barker (GCA Technical Director).

Dr. John Barker and GCA fulfil the criteria for a Qualified Person as specified in Catalist Rule 442. SGX recognises GCA as a Qualified Person as evidenced from previous acceptance of a number of other QPRs.

GCA can confirm that:

(a) The qualified person, being Dr. John W. Barker ("John Barker"), is not a sole practitioner;

(b) John Barker has been directly supervised by John Gaffney, Regional Director, on behalf of GCA. John Gaffney maintains a Power of Attorney, issued by GCA's parent company, Baker Hughes Inc., as Regional Director to represent GCA before all governmental and all regulatory authorities, departments, agencies and bodies, and to sign all documents required by any of the authorities mentioned;

(c) John Barker and GCA directors, substantial shareholders and their associates are independent of Rex, its directors and substantial shareholders;

(d) John Barker and GCA's directors, substantial shareholders and their associates do not have any interest, direct or indirect, in Rex, its subsidiaries or associated companies and will not receive benefits other than remuneration paid to John Barker/GCA in connection with the QPR; and

(e) The remuneration paid to John Barker/GCA in connection with the QPR is not dependent on the findings of the QPR.

# 2 Executive Summary

Edvard Grieg South (also known as Rolvsnes) was discovered in 2009 by well 16/1-12 and appraised in 2015 by well 16/1-25S. It is the first potentially commercial discovery in basement reservoir in Norwegian waters, so its development is the subject of considerable technical interest but there are no close Norwegian analogues to draw upon. Apart from the nearby 16/1-15 well, the next nearest significant discovery in basement reservoir is some 370 km WNW at the Lancaster discovery, in the UK West of Shetland area, which is also undeveloped at the present time.

Data for Edvard Grieg South obtained from the two well penetrations includes a good wire line log suite, considerable amounts of core and results of a drill stem test (DST) on the 16/1-25S well. The discovery is also covered by 3D seismic data.

A property description of the asset is provided in Table 1.

**Table 1: Edvard Grieg South Property Description**

| Asset Name/Country | Lime's Interest[1] (%) | Development Status | License Expiry Date | License Area | Type of Mineral, Oil or Gas Deposit | Remarks |
|---|---|---|---|---|---|---|
| Edvard Grieg South (Rolvsnes), Norway | 30% | Initial – Discovery | 17th December, 2019 | PL338C | Oil | Fractured Basement Reservoir |

**Note:**

1. Rex International Holding Limited (Rex) has an effective interest of 89.23% in Lime.

The asset is located offshore Norway; access to the asset is by standard offshore marine logistics, with the natural environment reflecting Norwegian Sea conditions. The cultural environment is typical North European with no reported issues pertinent to the continued asset development.

GCA has audited the Operator's volumetric assessment of stock tank oil initially in place (STOIIP) and the associated recoverable volumes of oil and gas. GCA considers that the recoverable volumes meet the definitions for classification as Contingent Resources under the PRMS.

GCA's estimates of Contingent Resources associated with the Edvard Grieg South Discovery are shown in Table 2. Resource estimates are also presented in Appendix III of this report in the format prescribed by SGX Listing Rules Appendix 7D.

The Operator is proposing a staged appraisal and development, in which up to four production wells and one water injection well will be drilled, all tied back to existing infrastructure. Results of each well, including an extended period of production, will be evaluated before deciding to drill the next well. GCA considers this to be a very sensible approach.

**Table 2: Edvard Grieg South Discovery Contingent Resources as at 31st January, 2017**

**(Gross and Net to Lime)**

| Edvard Grieg South | Contingent Resources (Gross) | | | Contingent Resources (Net to Lime) | | |
|---|---|---|---|---|---|---|
| | 1C | 2C | 3C | 1C | 2C | 3C |
| Oil (MMBBL) | 10.3 | 31.4 | 77.9 | 3.1 | 9.4 | 23.4 |
| Associated Gas (Bscf) | 10.4 | 31.8 | 78.7 | 3.1 | 9.5 | 23.6 |

**Notes:**

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the discovery in the event that development goes ahead.
2. Lime's Net Contingent Resources in this table are Lime's Working Interest fraction of the Gross Field Resources.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the discovery may not be developed in the form envisaged or may not be developed at all (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
5. Rex International Holding Limited (Rex) has an effective interest of 89.23% in Lime.

GCA's overall observations and conclusions are that there are still considerable uncertainties related to the recoverable resources from the discovery, and that the Operator's forward plan to appraise and develop the field in a step-wise manner is pragmatic and prudent. However, any assessment of recoverable resources at this stage must be considered as indicative only and it must be expected that resource estimates could change significantly as more data are acquired.

# 3 Asset Summary

## 3.1 License Summary

The Edvard Grieg South Discovery is located in license PL338C, some 30 km east of the international boundary between Norway and the UK where water depths are approximately 100 m. Edvard Grieg South is a reservoir in fractured and weathered granite basement on the Utsira High, just south of the Edvard Grieg field (Figure 1). According to the Norwegian Petroleum Directorate (NPD) web site, the PL338C license covers an area of 121.637 $km^2$.

The PL338 license was awarded in 2004 with an initial phase of 3 years but the license has been extended 6 times, and then more recently, PL338C was carved out from PL338 in December, 2014. The PL338C license is valid to mid-December 2019, with a deadline for "decision on concretization" (BoK) on 17th June, 2018. If no development activity is proposed by that date, the licence would be relinquished, but otherwise it would be expected that a production licence would be issued and renewed for as long as commercial production remains viable. The PL338C license obligations were fulfilled by drilling of well 16/1-25 S in 2015.

The discovery well, 16/1-12, was drilled in 2009 and the discovery was appraised in 2015 by well 16/1-25 S.

## 3.2 Geological Setting

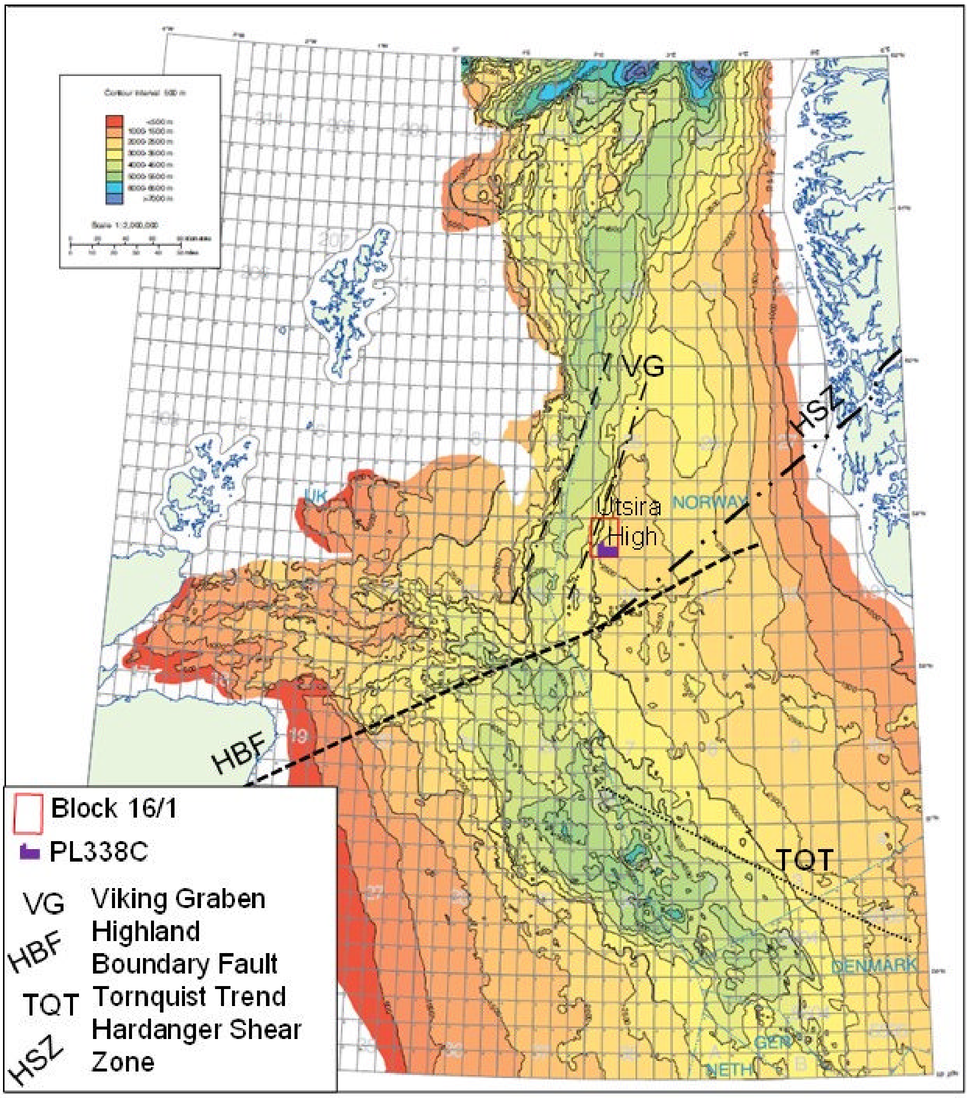
The PL338C area lies on the Utsira High near the southern tip of the Viking Graben (Figure 2).

In this area there are up to four intersecting structural fabrics which have been overlain as the area has evolved. The Highland Boundary fault was initiated in the Ordovician Grampian orogeny and reactivated later. The Tornquist trend, due to the Silurian closure of the Tornquist Sea is more strongly developed further south but is observed in the Silurian age basement of Edvard Grieg South. It is followed by the Devonian Hardangerfjord Shear Zone (Fossen & Hurich, 2005) and Highland Boundary Fault reactivation. These were in turn overprinted by the Late Jurassic opening of the Viking Graben.

These structural fabrics are preserved in the basement in the form of both large faults which define the edges of basement blocks and grabens, but also within blocks as a network of small faults and fractures, features which have the potential to be viable hydrocarbon reservoirs in their own right.

Numerous oil and gas fields, including the main Edvard Grieg field and the Luno II discovery, are located in the Mesozoic sedimentary section above and around this high but most wells which penetrated the basement have found it to be tight. The only exceptions are the two wells in Edvard Grieg South and 16/1-15, which lies in the north of the main Edvard Grieg field.

**Figure 2: Regional BCU Surface across the North Sea showing Trends Applicable to Edvard Grieg South**




Source: Modified after: Fraser, S I, Robinson, A M, Johnson, H D. Underhill, J R, Kadolsky, D G A, Connell, R, Johannessesn, P and Ravnås, R. 2002 Upper Jurassic, 157-189 in *The Millennium Atlas: petroleum geology of the central and northern North Sea*. Evans, D, Grahan, C, Armour, A, and Bathurst, P (editors and coordinators). *London: the Geological Society of London)

## 3.3 Database and Methodology

GCA has had access to primary data such as end of well reports, PVT reports, conventional core descriptions, DST results and MDT sampling summaries, as well as to secondary data such as petrophysical evaluation reports, interpretations for each well, DST interpretations and a report detailing the geological modelling undertaken by the Operator. The entire license is covered by multiple 3D seismic surveys. The most recent was shot in 2012. GCA also received digital copies of the top reservoir depth structure grid, a seismic refraction velocities grid and a field outline polygon. GCA did not have a copy of the static or dynamic models, or of the full seismic data, but these were not considered necessary for the purpose of this report.

GCA's approach focused on cross-checks of the existing evaluations in key discipline areas, with particular emphasis on aspects considered to be subject to the greatest uncertainty. The aim was to reach an independent opinion on the existing interpretations and estimates, and to establish whether they are reasonable. Any concerns identified were raised and discussed with Lime and/or Lundin. GCA made such adjustments to existing interpretations and estimates as it deemed necessary.

In instances where volumes are estimated using complex 3-dimensional models, it is appropriate to ground-truth the model results against the fundamental data. This was the workflow followed by GCA in this instance.

GCA considers that the available data were sufficient to enable the range of Contingent Resources to be estimated. However, the current lack of special core analysis (SCAL) data is a significant source of uncertainty and such data would be needed to gain confidence in the dynamic modelling results.

# 4 Technical Review

## 4.1 Well Summary

Both wells drilled on Edvard Grieg South are located at the same structural elevation and encountered a hydrocarbon column of about 30 m. The two wells show quite different wireline log characteristics. The Operator describes the basement rock as granodiorite at well 16/1-12 and monzogranite at well 16/1-25S.

The reservoir porosity in the basement is a combination of microfractures and matrix porosity, being caused by both physical and chemical weathering processes.

### 4.1.1 Well 16/1-12

Well 16/1-12 (2009) found oil in weathered and faulted/fractured granitic basement directly beneath tight sediments of the Cretaceous Cromer Knoll and Shetland Groups. The oil column was confirmed by oil sampling, pressure measurements and observations in both conventional and sidewall cores.

Well 16/1-12 found an undersaturated black oil with geochemical characteristics generally similar to that of the petroleum of the nearby Edvard Grieg field, however, with a different oil-water contact, suggesting a separate pool.

Petrophysical analysis showed average porosity to be 9%, with average matrix permeability of 1 mD. Three MiniDSTs were performed showing permeability of the weathered and fractured basement up to 700 mD. The oil-water contact was found at 1,954m MD, however, there were shows in the core and cuttings beneath this contact.

### 4.1.2 Well 16/1-25 S

This well was drilled in 2015, some 2.7 km south of well 16/1-12. The top basement was found at -1,898 m TVDss.

16/1-25 S was drilled as a deviated well (15° through basement) in order to cross more faults and test a wider area and in that way to get better control on variability, quality and thickness of the weathered zones. The well encountered an oil column of about 30 m in porous and fractured basement rock.

The pressure data shows this well is probably in the same compartment as the 16/1-12 oil discovery, with approximately the same OWC, although no direct communication has been demonstrated. The fluid type is oil with similar properties to the Edvard Grieg field oil. Extensive data acquisition and sampling was carried out in the reservoir including conventional coring and fluid sampling. One production test (DST) was performed across the oil leg. The DST produced a reported 42 Sm3/day, but showed a significant skin effect hampering production. A subsequent injectivity test gave a stable rate of 1,000 Sm3/day, corroborating the good permeability found in the 16/12-1 well.

## 4.2 STOIIP Estimates

### 4.2.1 Field Extent and Structure

The Edvard Grieg South discovery is an elevated footwall block, where the top of the basement meets the Base Cretaceous Unconformity (BCU).

The extent of the weathered and fractured area within the potential field extent is unknown but appears limited to the west and north by the faults bounding the Utsira High. The Operator has used seismic refraction velocity as an indicator of likely weathered basement during exploration, with slow refraction velocities being qualitatively equated to highly weathered basement.

Both wells are located in the central portion of the potential field area. Each found a weathered and fractured interval of 30-40 m with fractured interval below, exhibiting less weathering with depth.

Weathering might be expected to occur mostly at the top of the basement, but elsewhere on the Utsira High, crestal locations have been drilled and found to be tight.

Fracturing and weathering may also be concentrated around faults. Seismic data across Edvard Grieg South have been reprocessed to focus on basement rather than sedimentary cover and reveal a network of seismically resolvable faults which have been imaged by coherency type seismic attribute data. Typically the faults dip at angles of 30-60 degrees and have been demonstrated in the two wells on both FMI logs and core. Fracture intensity seen in core is reported to be between four and ten times that seen on FMI logs.

### 4.2.2 Volumetric Calculation

The Operator has constructed a static geological model of the reservoir. GCA does not have a copy of the model, but has reviewed reports on how it was constructed. GCA was supplied with a digital copy of the top reservoir surface in TWT and depth and the Operator's field outline, and was able to confirm a GRV down to a FWL of -1,927 m TVDss of 1,566 MMm$^3$. This 'container' is the basis of all the subsurface modelling.

The network of seismically resolvable faults has been sampled into the static model container direct from the seismic attribute volume and is the locus for sub-seismic scale fracture modelling. This is a standard and effective technique in fractured basement reservoirs and the faults can be tied back to the well control. Two fracture models were trialed with different fracture densities and apertures.

GCA has made its own estimates of STOIIP, varying the field extent as well as the petrophysical properties of the reservoir. Matrix porosity has been confined to a 30-40 m thick zone at the top of the basement, but fracturing has been assumed to be present at all depths.

GCA's Low – Best – High estimates of STOIIP are 77 –169 – 338 MMBbl respectively.

Given the subsurface uncertainties remaining in this field, which is the first of this type in the Norwegian North Sea and for which no closure is yet known, GCA considers its STOIIP range is appropriately broad at this early stage of appraisal.

### 4.2.3 Risks & Uncertainties

The main subsurface risks affecting STOIIP identified for Edvard Grieg South are:

- Areal extent of basement with matrix porosity/permeability;

- Presence of closed faults and or fractures rather than the anticipated open faults and fractures;
- Unexpected occlusion of permeability or porosity by high clay content; and
- Petrological variation within the basement such as sills or dykes.

## 4.3 Hydrocarbon Properties

Oil samples have been taken from well 16/1-12 and 16/1-25S. In both wells, oil samples were secured from two different depths. The oil in Edvard Grieg South is under-saturated with normal properties.

GCA was advised that detailed work on production chemistry is planned for the next phase, involving wax properties, hydrate prediction, fluid compatibility testing and scale evaluations. Trace elements (H2S, CO2, Hg, Mercaptans) will be sampled during the planned DST on the next well.

GCA does not consider that the PVT analysis is critical to uncertainties in the resource assessment.

## 4.4 Assessment of Contingent Resources

GCA has estimated a range of recovery factors for both the matrix and fracture systems that is considered to be reasonable for a range of recovery mechanisms. The proportion of matrix system STOIIP increases from the Low to the High case. In addition, there is more uncertainty in the benefits of water injection on matrix oil recovery compared with the fracture system and the contribution from the matrix hence becomes progressively more significant towards the High case.

GCA's estimated range of recovery factors is summarized in **Table 3**. Although there is a considerable range in recovery factors for both the matrix and fracture systems, the combined range is much narrower, owing to the increasing proportion of matrix STOIIP towards the High case.

**Table 3: Oil and Gas Recovery Factors Applied by GCA (%)**

| | 1C | 2C | 3C |
|---|---|---|---|
| Matrix | 5.0 | 10.0 | 15.0 |
| Fractures | 20.0 | 30.0 | 40.0 |
| Combined | 13.4 | 18.6 | 23.1 |

GCA has also estimated gas Contingent Resources without making any provision for fuel, flare, shrinkage or other losses. Based on the PVT data for well 16/1-25S, GCA has applied a fixed GOR of 180 $m^3/m^3$ (1,010 scf/bbl) for all three resource categories.

The oil and gas Contingent Resources for the Edvard Grieg South discovery are summarised in **Table 2.**

# 5 Financial Analysis

GCA has not conducted any economic analysis of the proposed development project; none is required for Contingent Resources, which are not required to be economic.

Financial analysis of the operations, taxes, liabilities and marketing are not considered as applicable for the QPR given the nascent nature of the project to develop the Edvard Grieg South discovery.

The Norwegian fiscal regime consists of two profit-based taxes, corporate income tax at a rate of 24% and the Resource Rent Tax at 54%.  The tax basis is essentially the same for both taxes. Additionally, a company which, due to losses, is not in a tax position may each year claim reimbursement of the tax value of exploration expenses and abandonment costs from the government.

# 6 Recommendations

- GCA agrees with the Operator, Lundin’s, current plan to de-risk the Edvard Grieg South discovery by carrying out further technical work.
- No further recommendations are considered at this time.

# 7 References

1. Fossen, S & C A Hurich, Journal of the Geological Society, London, Vol 162, 2005, pp. 675-687

2. EG South Summary – Lime, January 2017

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# Appendix I
# SPE PRMS Definitions and Guidelines (Abridged)

Gaffney, Cline & Associates

**Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers**
**Petroleum Resources Management System**
**Definitions and Guidelines ([1])**

**March 2007**

## 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.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

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 SPE PRMS 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.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

## 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.

### 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.

**Proved Reserves**

*<u>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</u>.*

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**

*<u>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.</u>*

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 areas 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.

**Possible Reserves**

*<u>Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves</u>*

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.

**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.

**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.

## 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.

### 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.*

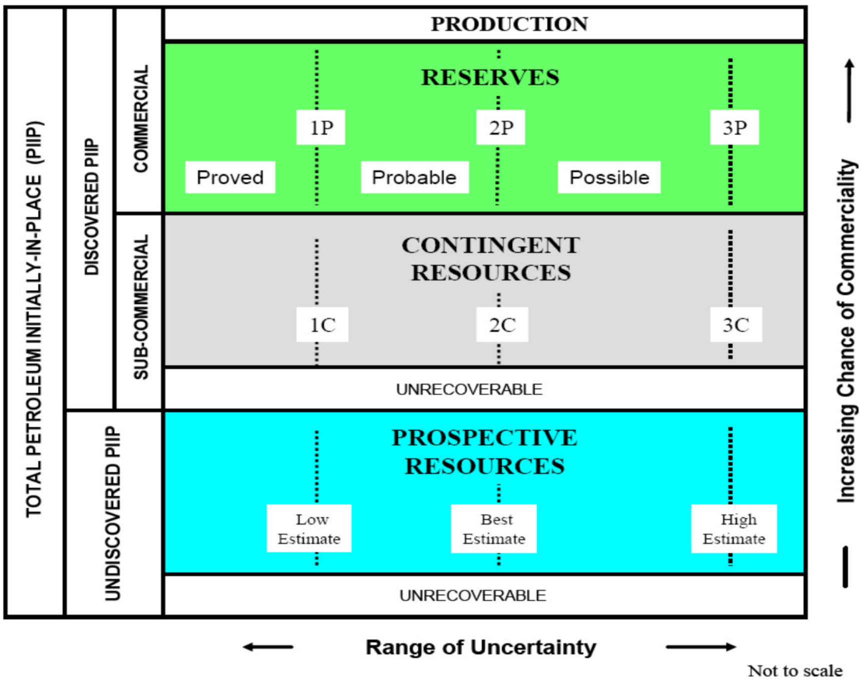
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

### Play

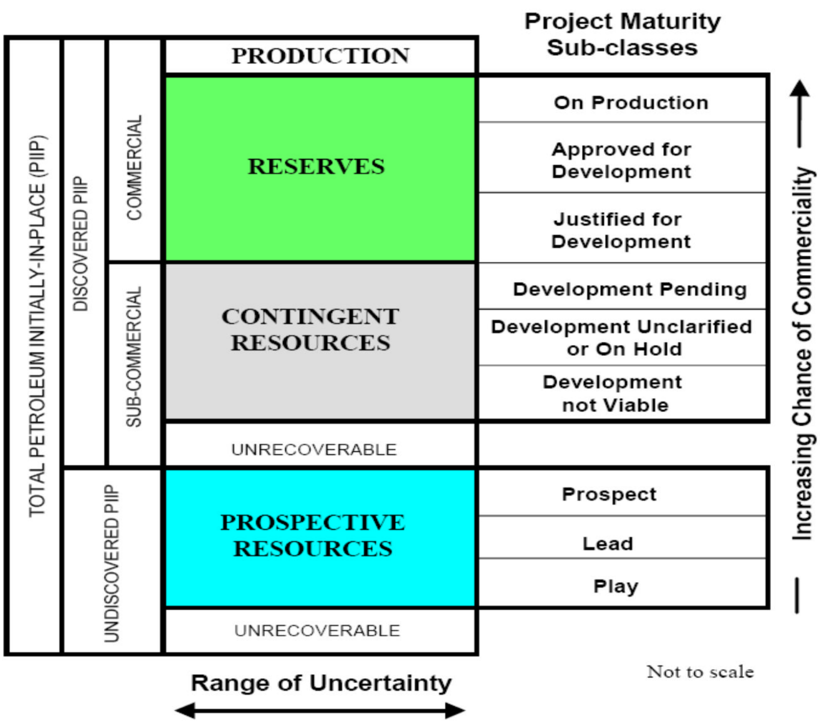
*A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.*

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.

## RESOURCES CLASSIFICATION




## PROJECT MATURITY



# Appendix II
# Glossary

# GLOSSARY

## List of Standard Oil Industry Terms and Abbreviations

| | | | |
|---|---|---|---|
| ABEX | Abandonment Expenditure | FPSO | Floating Production, Storage and Offloading |
| ACQ | Annual Contract Quantity | Ft | Foot/feet |
| °API | Degrees API (American Petroleum Institute) | FWL | Free water level |
| AAPG | American Association of Petroleum Geologists | Fx | Foreign Exchange Rate |
| AVO | Amplitude versus Offset | G | gram |
| A$ | Australian Dollars | g/cc | grams per cubic centimetre |
| B | Billion ($10^9$) | Gal | gallon |
| Bbl | Barrels | gal/d | gallons per day |
| /Bbl | per barrel | G&A | General and Administrative costs |
| BBbl | Billion Barrels | GBP | Pounds Sterling |
| BHA | Bottom Hole Assembly | GDT | Gas Down to |
| BHC | Bottom Hole Compensated | GIIP | Gas initially in place |
| Bscf or Bscf | Billion standard cubic feet | GJ | Gigajoules (one billion Joules) |
| Bscfd or Bscfd | Billion standard cubic feet per day | GOR | Gas Oil Ratio |
| $Bm^3$ | Billion cubic metres | GRV | Gross Rock Volume |
| Bcpd | Barrels of condensate per day | GTL | Gas to Liquids |
| BHP | Bottom Hole Pressure | GWC | Gas water contact |
| Blpd | Barrels of liquid per day | HDT | Hydrocarbons Down to |
| Bpd | Barrels per day | HSE | Health, Safety and Environment |
| Bo | Formation Volume Factor - Oil | HSFO | High Sulphur Fuel Oil |
| Boe | Barrels of oil equivalent @ 6 mcf/Bbl | HUT | Hydrocarbons up to |
| boepd | Barrels of oil equivalent per day @ 6 mcf/Bbl | $H_2S$ | Hydrogen Sulphide |
| BOP | Blow Out Preventer | IOR | Improved Oil Recovery |
| Bopd | Barrels oil per day | IPP | Independent Power Producer |
| Bwpd | Barrels of water per day | IRR | Internal Rate of Return |
| BTU | British Thermal Units | J | Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU) |
| Bwpd | Barrels water per day | k | Permeability |
| CBM | Coal Bed Methane | KB | Kelly Bushing |
| $CO_2$ | Carbon Dioxide | kh | Permeability Thickness |
| CAPEX | Capital Expenditure | KJ | Kilojoules (one Thousand Joules) |
| CCGT | Combined Cycle Gas Turbine | kl | Kilolitres |
| cm | centimetres | km | Kilometres |
| CMM | Coal Mine Methane | $km^2$ | Square kilometres |
| CNG | Compressed Natural Gas | kPa | Thousands of Pascals (measurement of pressure) |
| Cp | Centipoise (a measure of viscosity) | KW | Kilowatt |
| CSG | Coal Seam Gas | KWh | Kilowatt hour |
| CT | Corporation Tax | LKG | Lowest Known Gas |
| DCQ | Daily Contract Quantity | LKH | Lowest Known Hydrocarbons |
| Deg C | Degrees Celsius | LKO | Lowest Known Oil |
| Deg F | Degrees Fahrenheit | LNG | Liquefied Natural Gas |
| DHI | Direct Hydrocarbon Indicator | LoF | Life of Field |
| DST | Drill Stem Test | LPG | Liquefied Petroleum Gas |
| DWT | Dead-weight ton | LTI | Lost Time Injury |
| E&A | Exploration & Appraisal | LWD | Logging while drilling |
| E&P | Exploration and Production | m | Metres |
| EBIT | Earnings before Interest and Tax | M | Thousand |
| EBITDA | Earnings before interest, tax, depreciation and amortisation | $m^3$ | Cubic metres |
| EI | Entitlement Interest | Mcf or Mscf | Thousand standard cubic feet |
| EMV | Expected Monetary Value | MCM | Management Committee Meeting |
| EUR | Estimated Ultimate Recovery | mD | Measure of Permeability in millidarcies |
| FEED | Front End Engineering and Design | MD | Measured Depth |

| | | | |
|---|---|---|---|
| FMI | Formation MicroImager | MDT | Modular Dynamic Tester |
| Mean | Arithmetic average of a set of numbers | $R_w$ | Resistivity of water |
| Median | Middle value in a set of values | SCAL | Special core analysis |
| MFT | Multi Formation Tester | cf or scf | Standard Cubic Feet |
| mg/l | milligrams per litre | cfd or scfd | Standard Cubic Feet per day |
| MJ | Megajoules (One Million Joules) | scf/ton | Standard cubic foot per ton |
| $Mm^3$ | Thousand Cubic metres | SL | Straight line (for depreciation) |
| $Mm^3d$ | Thousand Cubic metres per day | $s_o$ | Oil Saturation |
| MM | Million | SPE | Society of Petroleum Engineers |
| MMBbl | Millon of barrels | SPEE | Society of Petroleum Evaluation Engineers |
| MMBTU | Millions of British Thermal Units | Ss | Subsea |
| Mode | Value that exists most frequently in a set of values = most likely | Stb | Stock tank barrel |
| Mscfd | Thousand standard cubic feet per day | STOIIP | Stock tank oil initially in place |
| MMscfd | Million standard cubic feet per day | $s_w$ | Water Saturation |
| MW | Megawatt | Swi | Initial Water Saturation |
| MWD | Measuring While Drilling | T | Tonnes |
| MWh | Megawatt hour | TD | Total Depth |
| mya | Million years ago | Te | Tonnes equivalent |
| NaCl | Sodium Chloride | THP | Tubing Head Pressure |
| NGL | Natural Gas Liquids | TJ | Terajoules ($10^{12}$ Joules) |
| $N_2$ | Nitrogen | Tscf or Tcf | Trillion standard cubic feet |
| NTG | Net-to-gross | TCM | Technical Committee Meeting |
| NOK | Norwegian Kroner | TOC | Total Organic Carbon |
| NPV | Net Present Value | TOP | Take or Pay |
| OBM | Oil Based Mud | Tpd | Tonnes per day |
| OCM | Operating Committee Meeting | TVD | True Vertical Depth |
| ODT | Oil down to | TVDss | True Vertical Depth Subsea |
| OPEX | Operating Expenditure | TWT | Two Wat Traveltime |
| OWC | Oil Water Contact | USGS | United States Geological Survey |
| p.a. | Per annum | US$ | United States Dollar |
| Pa | Pascals (metric measurement of pressure) | VSP | Vertical Seismic Profiling |
| P&A | Plugged and Abandoned | WC | Water Cut |
| PD | Proved Developed | WI | Working Interest |
| PDP | Proved Developed Producing | WPC | World Petroleum Council |
| PDnP | Proved Developed Non-Producing | WTI | West Texas Intermediate |
| PI | Productivity Index | wt% | Weight percent |
| PJ | Petajoules ($10^{15}$ Joules) | | |
| PPM | Parts per Million | 1H05 | First half (6 months) of 2005 (example of date) |
| PSDM | Post Stack Depth Migration | 2Q06 | Second quarter (3 months) of 2006 (example of date) |
| Psi | Pounds per square inch | 2D | Two dimensional |
| Psia | Pounds per square inch absolute | 3D | Three dimensional |
| Psig | Pounds per square inch gauge | | |
| p.u. | Porosity Unit | 4D | Four dimensional |
| PUD | Proved Undeveloped | 1P | Proved Reserves |
| PVT | Pressure volume temperature | 2P | Proved plus Probable Reserves |
| P10 | 10% Probability | 3P | Proved plus Probable plus Possible Reserves |
| P50 | 50% Probability | % | Percentage |
| P90 | 90% Probability | | |
| MMcf or MMscf | Million standard cubic feet | | |
| $m^3d$ | Cubic metres per day | | |
| Rf | Recovery factor | | |
| RFT | Repeat Formation Tester | | |
| RT | Rotary Table | | |

Gaffney, Cline & Associates

# Appendix III
# Summary of Reserves and Resources
# (SGX Listing Rules Appendix 7D)

Lime Petroleum Norway AS
10th March, 2017

## SUMMARY OF RESERVES AND RESOURCES

## (SGX Listing Rules Appendix 7D)

Edvard Grieg South, Norway

| Category | Gross Attributable to License (MMstb / Bscf) | Net Attributable to Lime | | Remarks |
|---|---|---|---|---|
| | | (MMstb / Bscf) | Change from previous update (%) | |
| **Reserves** | | | | |
| **Oil Reserves** | | | | |
| 1P | N/A | N/A | N/A | |
| 2P | N/A | N/A | N/A | |
| 3P | N/A | N/A | N/A | |
| **Natural Gas Reserves** | | | | |
| 1P | N/A | N/A | N/A | |
| 2P | N/A | N/A | N/A | |
| 3P | N/A | N/A | N/A | |
| **Natural Gas Liquids Reserves** | | | | |
| 1P | N/A | N/A | N/A | |
| 2P | N/A | N/A | N/A | |
| 3P | N/A | N/A | N/A | |
| **Contingent Resources** | | | | |
| ***Oil*** | | | | |
| **1C** | **10.3** | **3.1** | **N/A** | |
| **2C** | **31.4** | **9.4** | **N/A** | No previous update. |
| **3C** | **77.9** | **23.4** | **N/A** | |
| ***Natural Gas*** | | | | |
| **1C** | **10.4** | **3.1** | **N/A** | |
| **2C** | **31.8** | **9.5** | **N/A** | No previous update. |
| **3C** | **78.7** | **23.6** | **N/A** | |

Lime Petroleum Norway AS
10th March, 2017

| *Natural Gas Liquids* | | | | |
|---|---|---|---|---|
| 1C | N/A | N/A | N/A | |
| 2C | N/A | N/A | N/A | |
| 3C | N/A | N/A | N/A | |
| | | | | |

| Category | Gross Attributable to License (MMstb / Bscf) | Net Attributable to Lime | | Remarks |
|---|---|---|---|---|
| | | (MMstb / Bscf) | Change from previous update (%) | |
| **Prospective Resources** | | | | |
| ***Oil*** | | | | |
| Low Estimate | N/A | N/A | N/A | |
| Best Estimate | N/A | N/A | N/A | |
| High Estimate | N/A | N/A | N/A | |
| ***Natural Gas*** | | | | |
| Low Estimate | N/A | N/A | N/A | |
| Best Estimate | N/A | N/A | N/A | |
| High Estimate | N/A | N/A | N/A | |

**Notes:**

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the discovery in the event that development goes ahead.
2. Lime's Net Contingent Resources in this table are Lime's Working Interest fraction of the Gross Field Resources.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the discovery may not be developed in the form envisaged or may not be developed at all (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
5. Rex International Holding Limited (Rex) has an effective interest of 89.23% in Lime.

1P: Proved; 2P: Proved + Probable; 3P: Proved + Probable + Possible

MMstb: Millions of stock tank barrels; Bscf: Billions of standard cubic feet

| | |
|---|---|
| Name of Qualified Person: | Dr. John Barker |
| Date: | 10th March, 2017 |
| Professional Society Affiliation / Membership: | The Society of Petroleum Engineers (SPE) |