

Annual Statement of Reserves

Classification of Reserves and Contingent Resources

The reserve and contingent resource volumes have been classified in accordance with the NPD classification system http://www.npd.no/global/norsk/5%20-%20regelverk/tematiske%20veiledninger/ressursklassifisering_n.pdf and are consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources, see figure below.

Figure 1: NPD's classification system used by Det norske oljeselskap

	Potential Resources		Contingent Resources				Reserves		
NPD category	9	8	7	6	5	4	3	2	1
Description	Leads. Conceptual ideas of possible prospects	Prospects. A mapped rock volume believed to contain hydrocarbons	Discoveries under evaluation	Discoveries where development is unlikely	Discoveries where development is likely	Discoveries where development is being planned	Fields where PDO has been concluded by the Licensees	Fields under development, PDO approved	Fields in production

Reserves, Developed and Non-developed

Det norske oljeselskap ASA has interests in five fields containing reserves, of which four are in production (Category 1) and one is non-developed (Category 3):

- Varg – operated by Talisman, Det norske 5%
- Glitne – operated by Statoil, Det norske 10%
- Enoch – operated by Talisman, Det norske 2%
- Jotun – operated by ExxonMobil, Det norske 7%
- Frøy – operated by Det norske 50%, non-developed.

The net reserves for the five fields are presented in Table 1 and amounts to a total of 29.13 million barrels oil equivalents (2P/P50 or best estimate) for the three different categories. Of these volumes 1.56 million barrels are classified as “developed”, 0.21 million barrels as “under development”, and 27.36 million barrels as “non-developed”. The non-developed volumes are all assigned to Frøy.

The changes in reserves during 2009 are presented in Table 2. On the 2P/P50 basis, there is an overall reduction of 0.87 million barrels of oil equivalents from year-end 2008 composite for the three categories. This reduction is due to the production of 0.67 million barrels and a minor negative adjustment of 0.55 million barrels for the Frøy volumes, and is partly offset by net positive revisions of 0.40 million barrels for Varg and Glitne.

Table 1 – Reserves by field

Reserves										
1x10 ⁹ Sm ³ gas = 1x10 ⁶ Sm ³ o.e. = 6.29 MBOE										
Developed assets (Category 1)										
As of 31.12.2009	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
PL 038 - Varg	7.06	0.0	7.06	5%	0.35	12.90	0.0	12.90	5%	0.65
PL 048 B - Glitne	0.64	0.0	0.64	10%	0.06	1.62	0.0	1.62	10%	0.16
Enoch Unit (Norway)	1.28	0.0	1.31	10%	0.13	1.48	0.01	1.52	10%	0.15
Jotun Unit	7.64	0.0	7.64	7%	0.53	8.43	0.04	8.66	7%	0.60
Total					1.08					1.56
Under development (Category 2)										
As of 31.12.2009	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	Liquids (mdbl)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
PL 038 - Varg	1.99	0.0	1.99	5%	0.10	4.16	0.0	4.16	5%	0.21
Total					0.10					0.21
Non-developed assets (Category 3)										
As of 31.12.2009	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
PL 364 - Frøy	33.97	0.0	33.97	50%	16.98	54.72	0.0	54.72	50%	27.36
Total					16.98					27.36

Table 2 – Aggregated reserves, production, developments, and adjustments

Reserves development Net attributed million barrels of oil equivalents. Calendar years, reporting as of year end.	Developed assets		Under development		Development decided	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
	Balance as of 31.12.2008	1.12	1.74	0	0.35	17.09
Production	-0.67	-0.67				
Acquisitions/disposals						
Extensions and discoveries						
New developments		0.14				
Revisions of previous estimates	0.63	0.35	0.10	-0.14	-0.11	-0.55
Balance as of 31.12. 09	1.08	1.56	0.10	0.21	16.98	27.36

The **Varg Field** (PL 038) is located to the south of Sleipner Øst. The field is developed with the production vessel “Petrojarl Varg” with integrated oil storage, and connected to a wellhead platform. Oil is exported using shuttle tankers. Two new wells were completed in 2009, proving up new reserves and increasing the total production to around 26,800 bopd by year-end. Total ultimate recoverable reserves are estimated to 95 million barrels of oil, while total remaining proved and probable reserves are 17.1 million barrels. Of these 12.9 million barrels are classified as developed (Category 1) and contain the volumes from the base case production profile assuming no further infill drilling and a production cut-off mid 2013, when the current FPSO lease expires. Reserves “under development” (Category 2) of 4.2 million barrels are associated with planned wells in 2010 and onward.

The **Glitne Field** (PL 048 B) is located 40 kilometers northeast of the Sleipner area. The field is produced by sub-sea wells tied to the production vessel “Petrojarl 1”, and oil is exported using shuttle tankers. Total reserves are determined by the operator based on a production cut-off in February 2011. The main uncertainty in future production is the water cut development for individual wells. Remaining reserves are assessed probabilistically considering relevant uncertainties related to the production. Total initial recoverable reserves are estimated at 52 million barrels of oil, while remaining reserves are estimated at 1.6 million barrels of oil. A new infill production well will likely be drilled in 2010 and could potentially extend the life of the field by 2-3 years. Associated volumes of 3.4 million barrels are not included as reserves but classified as resources in Category 5.

The **Enoch Field** (PL 048 D) straddles the Norwegian/UK border and is located in the UK block 16/13a and in the Norwegian block 15/5 southwest of the Glitne Field. The field is developed by a single, horizontal sub-sea well and tied back to the UK Brae A platform where the oil is processed and exported via the Forties pipeline network. The gas is sold to the Brae Field. Production started in May 2007 and field shut down is expected in 2016. Depending on reservoir performance, one additional producer may be drilled using the extra well slot which is available. The field has been unitized with the license owners in British sector, and Det norske’s overall share is 2% (10% of the Norwegian license PL 048 D). Total initial proved plus probable reserves (Enoch Unit) are estimated by the operator to 15 million barrels of oil equivalents of which 7.8 million barrels remain. Volumes in Table 1 include only the Norwegian part of the field and are included under “Developed assets”.

The **Jotun Field** (PL 027 B, PL 103) is developed with an integrated well head platform (Jotun B) of 24 well slots and a FPSO (Jotun A). Oil is shuttled to the Slagen refinery and gas is exported into Statpipe. Proved plus probable reserves (2P/P50) include expected volume from existing wells, assuming no new wells being drilled and abandonment of the field in 2015. Remaining reserves are determined by the operator based on decline analysis. The main uncertainty in future production is the water cut development in individual wells. Total initial recoverable reserves are estimated at 148 million barrels of oil. Total remaining proved and probable reserves are estimated at 8,6 million barrels oil and classified as “Developed assets”. The operator is assessing the economic viability of carrying out work-overs in wells currently not producing.

Det norske’s share of production from the Varg, Glitne, Enoch, and Jotun fields during 2009 amounts to 0.67 million barrels of oil equivalents.

A PDO for the reactivation of the **Frøy Field** (PL 364) was submitted to the authorities in September 2008 and acceded to by both Det norske (50% and operator) and Premier Norge AS (50%). Historically, the field was in production from 1995 to 2001 and produced 35 million barrels with Elf as operator. Based on a comprehensive evaluation of the reservoir and production history, the best estimate is that the recovery factor can be increased from the original 18 % to at least 40 %, increasing the recovered volumes by 55 million barrels. Of these volumes 34 million barrels are considered proved. This number corresponds to the P90 reserve estimate obtained in uncertainty studies performed prior to the PDO submission in 2008. Subsequent to the submission, MPE granted an extension of the license for 10 years until 2019. Due to the severe downturn in the financial markets, the Frøy redevelopment was put on hold. New efforts have been performed in 2009 to decrease the development costs and to reduce the resource uncertainty range. Pre-FEED studies have been initiated early 2010 with several potential contractors in order to firm up the development concept and to verify the cost estimates. Det norske and Premier plan to submit a modified PDO to the authorities in 2010 targeting a production start-up mid 2013.

Contingent Resources

Det norske oljeselskap ASA has interests in 19 discoveries classified as contingent resources and a complete list is provided below. Figure 2 illustrates resource movements for fields and discoveries in 2009. Det norske participated in seven discoveries in 2009. Six of these may have the potential of being commercial and are classified in Category 7 “under evaluation”. These include Jetta, Freke, Fulla, Grevling, Ragnarrock Graben and Frigg Delta.

Two of the discoveries, PL 028 B Hanz and PL 029 B Ermintrude, have been moved to Category 4 following decisions for concretization (BOK) by the license partners. PL 001 B Draupne remains in Category 5 awaiting the result of the appraisal well to be drilled in Q1, 2010. Two of the producing fields, Varg and Glitne, also have contingent resources in Category 4 and 5 related to planned IOR activities as discussed above.

Discoveries in Category 4 (development being planned):

- PL 028 B (Well 25/10-8) Hanz – operated by Det norske 35%
- PL 029 B (Well 15/6-9 S) Ermintrude – operated by Statoil, Det norske 20%

Discoveries in Category 5 (development likely):

- PL 001 B (Well 16/1-9) Draupne - operated by Det norske 35%
- PL 048 B (Well 15/5-5) Glitne – operated by Statoil, Det norske 10%

Discoveries in Category 7 (Under evaluation):

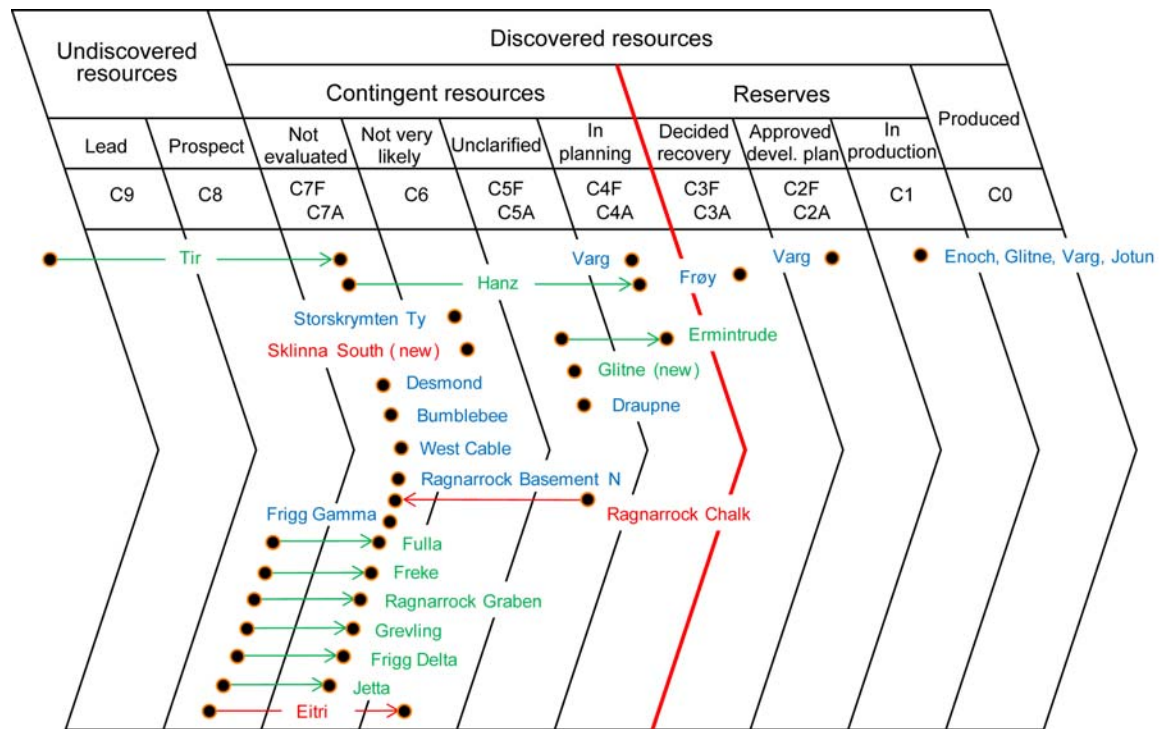
- PL 027 D, PL 504, PL 169 C (Well 26/8-17) Jetta – operated by Det norske 60%
- PL 029 B (Well 15/6-10) Freke – operated by Statoil, Det norske 20%
- PL 035 B and PL 362 (Well 30/11-7) Fulla – operated by Statoil, Det norske 15%
- PL 038 D (Well 15/12-23) Grevling – operated by Talisman, Det norske 30%
- PL 102 C (Well 25/5-5) Tir – operated by Total, Det norske 10%
- PL 242 (Well 16/1-7) West Cable – operated by Det norske 35%
- PL 265 (Well 16/2-3) Ragnarrock Chalk – operated by Statoil, Det norske 20%
- PL 265 (Well 16/2-3) Ragnarrock Basement North – operated by Statoil, Det norske 20%

- PL 265 (Well 16/2-5) Ragnarrock Graben – operated by Statoil, Det norske 20%
- PL 332 (Well 2/2-2) Desmond – operated by Talisman, Det norske 40%
- PL 332 (Well 2/2-5) Bumblebee – operated by Talisman, Det norske 40%
- PL 442 (Well 25/2-10 S) Frigg Gamma – operated by Statoil, Det norske 20%
- PL 442 (Well 25/2-17) Frigg Delta – operated by Statoil, Det norske 20%

Discoveries in Category 6 (Development unlikely):

- PL 027 D (Well 25/8-16S) Eitri – operated by ExxonMobil, Det norske 60%
- PL 256 (Well 6406/1-2 Sklinna South – operated by Det norske 55%
- PL 337 (Well 15/12-18S) Storskrynten – operated by Det norske 45%

Figure 2 – Resource movements 2009



Management's Discussion and Analysis

In general, the assessment of reserves and resources is carried out by experienced professionals in Det norske based on input from operators, partners, and in-house evaluations. The responsibility to carry out the evaluation lies with the business projects. The reserves and resource accounting is coordinated and quality controlled by a small central group of professionals, each of the members with more than 20 years of experience in such assessments. Furthermore the reported reserve volumes and classification are reviewed and approved by the company's management and the Board's audit group.

Specifically, the volumes for the five fields containing reserves are based on the operator's evaluation and no independent verification has been carried out. Volumes for Glitne, Jotun and Frøy are based on RNB 2010 (Revised National Budget) reported by the operator and adjusted for production where relevant. The Varg volumes have been updated by the operator reflecting the results of recent infill wells. The Enoch Field is operated from the UK side and is not subject to RNB reporting.

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated in the various licenses on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow or when facility lease expires. The discount rate applied is 10.7 percent nominal after tax. The company has used a long term inflation expectation of 2.5 percent, and a long term exchange rate expectation of NOK/USD 6.00. Oil prices are based on forward curve, starting at 80.9 USD/bbl as average in 2010 and increasing to 99 USD/bbl in 2017 (source: ICE Brent Crude 31.12.2009).

The calculations of recoverable volumes are, however, associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 estimate reflects our high confidence volumes. The methods used for subsurface mapping do not expose all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Therefore there is a certain chance that actual results may be lower than the 1P/P90. A significant change in oil prices may impact the reserves. Low oil prices may force the licensees to close down producing fields early and lead to lower production. Higher oil prices may extend the life time of the fields beyond what is currently assumed.

The reserves for the **Varg Field** are based on a production cut-off date mid 2013, when the lease for the FPSO vessel expires. A successful infill well drilled in 2009 increased the production by 40% at the end of 2009. Further infill drilling is planned, and the chance of extending economic production beyond 2013 is good. Furthermore, the recent Grevling discovery, if tied to Varg, may also have a positive impact on delaying Varg abandonment.

The planned shut-down on the **Glitne Field** has been postponed until February 2011, at the earliest. It has been decided to drill a new production well in 2010, and if successful, this may extend the field life by two to three years.

The **Enoch Field** is producing from one well and there is no firm plan for additional producers. However, depending on reservoir performance, an additional well may be drilled using a spare well slot.

The reserves of the **Jotun Field** include only expected volumes produced from existing wells and assumed field abandonment in 2015. The operator is assessing the economic viability for work-overs in two wells which are shut-in due to tubing leaks. Det norske has taken over the operatorship of PL 027D including the recent Jetta discovery and is currently evaluating if it can be commercially exploited as a tie-in to Jotun.

A PDO for the reactivation of the **Frøy Field** was submitted to the authorities in September 2008 and the MPE granted an extension of the license for 10 years until 2019. Subsequently, the Frøy development was put on hold due to the severe downturn in the financial markets. Since then focus has been on decrease of development costs and reducing uncertainty in the range of reserves. Studies have been initiated with several potential contractors in order to firm up the development concept and to verify cost estimates. Det norske and partner Premier plan to submit a modified PDO in 2010, targeting a production start-up in mid 2013. In parallel Det norske with partners is actively exploring in the area in order to prove up additional resources. The East Frigg Delta discovery was made in 2009 and confirmed the potential of the East Frigg Gamma-Delta area. Two more exploration wells will be drilled in the vicinity of Frøy during 2010.

Contingent resources in Category 4 and 5 include the **Hanz/Draupne discoveries** and the **Ermintrude discovery**. Considerable work has been carried out in 2009 to progress Hanz and Draupne towards development. A decision on concretization (BOK) for Hanz has been supported by the partners. An appraisal well will be completed on Draupne during Q1 2010 and the result will be important for selecting the development concept for the area. A phased development to achieve early production is one option being considered. Most likely total volumes for Hanz and Draupne are 17 million and 90 million barrels of oil equivalents, respectively. The Draupne volumes have a considerable uncertainty range which will be addressed by an appraisal well in 2010. Det norske is operator and has a 35 % interest in both discoveries. The Ermintrude discovery in PL 303 extends into PL 029 B, where Det norske has a 20% interest. A cost sharing agreement has been signed where PL 029 B covers 10% of the costs. The majority of the partners have supported a decision on concretization (BOK) for the Dagny/Ermintrude complex. Consequently, resources of 4.4 million barrels (net to Det norske) are classified in Category 4 and are based on a 10% share of Ermintrude in PL 029 B.

Six of the 2009 discoveries in which Det norske participated are classified in Category 7 "under evaluation". These include Jetta, Freke, Fulla, Grevling, Ragnarrock Graben and Frigg Delta. Technical and economical evaluation of these discoveries is ongoing in order to establish their commercial viability.

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Disclaimer

This Annual Statement of Reserves (“ASR”) includes and is based, inter alia, on forward-looking information and statements that are subject to risks and uncertainties. Such information and statements are only predictions, and actual events or results may differ materially. The ASR is based, inter alia, on current expectations, estimates, and projections about technical, geological, geotechnical and economic assumptions on which the reserve and resource estimates are made as well as global economic conditions, the economic conditions of the regions and industries that are major markets for Det norske oljeselskap ASA (including subsidiaries and affiliates) and its lines of business. These expectations, estimates and projections are generally identifiable by statements containing words such as “expects”, “believes”, “estimates” or similar expressions. Important factors that could cause actual results to differ materially from those expectations include, among others, technical, geological and geotechnical conditions, economic and market conditions in the geographic areas and industries that are or will be major markets for businesses of Det norske oljeselskap ASA (including subsidiaries and affiliates), oil prices, market acceptance of new products and services, changes in governmental regulations, interest rates, fluctuations in currency exchange rates and such other factors as may be discussed from time to time in the ASR. Although Det norske oljeselskap ASA believes that its expectations and this ASR are based upon reasonable assumptions, the company can not give any assurance that the expectations will be achieved or that the actual results will be as set out in the ASR. None of Det norske oljeselskap ASA or its subsidiaries or any such entities’ directors, employees or advisors makes any representation or warranty, expressed or implied, as to the accuracy, reliability or completeness of any information contained in the ASR, and no such entities or persons shall have any liability whatsoever arising directly or indirectly from the use of this ASR.

Appendix 1: Conversion factors, definitions, and abbreviations

Conversion factors:

1 Sm³ of oil = 1.0 Sm³ o.e.
 1 Sm³ of condensate = 1.0 Sm³ o.e.
 1000 Sm³ of gas = 1.0 Sm³ o.e.
 1 tonne of NGL = 1.9 Sm³ NGL = 1.9 Sm³ o.e.

Gas:

1 cubic foot	1 000.00 Btu
1 cubic metre	9 000.00 kcal
1 cubic metre	35.30 cubic feet

Crude oil:

1 Sm ³	6.29 barrels
1 Sm ³	0.84 toe
1 tonne	7.49 barrels
1 barrel	159.00 litres
1 barrel/day	48.80 tonnes/yr
1 barrel/day	58.00 Sm ³ per yr

Definitions and abbreviations:

1C: Denotes low estimate scenario of Contingent Resources.

2C: Denotes best estimate scenario of Contingent Resources.

3C: Denotes high estimate scenario of Contingent Resources.

1P: Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.

2P: Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.

3P: Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.

Accumulation: An individual body of naturally occurring petroleum in a reservoir.

°API: an indication of the specific gravity of crude oil measured on the API gravity scale.

Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

Appraisal well: A well drilled to confirm the size or quality (commercial potential) of a hydrocarbon discovery. Before development, a discovery is likely to need at least two or three such wells (see delineation well and exploration well).

ASR: Annual Statement of Reserves, report to be filed annually to the Oslo Stock Exchange.

CAPEX: Capital expenses.

Bcf: Billion cubic feet

bill.: billions

bbf: barrel (of oil)

boe: barrel of oil equivalent of natural gas and crude oil

boe/d: barrel of oil equivalent per day.

CO: carbon monoxide

CO₂: carbon dioxide

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 are a class of discovered recoverable resources.

Deterministic Estimate: The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.

E & P: Exploration and production.

Exploration: Prospecting for undiscovered petroleum.

Exploration well: A well drilled to test a potential but unproven hydrocarbon trap or structure where good reservoir rock and a seal or closure combine with a potential source of hydrocarbons (see appraisal well and delineation well).

FEED: Front-end Engineering and Design.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.

Flow Test: An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).

High Estimate: With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Hydrocarbons: Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.

Known Accumulation: An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as “known,” and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.

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. A project maturity sub-class that reflects the actions required to move a project toward commercial production.

Low Estimate: With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

m³: cubic metres.

Mbbl: Million bbl

MBOE: Millions of Barrels of Oil Equivalent.

MD&A: Management Discussion and Analysis.

mill.: millions

NCS: the Norwegian Continental Shelf.

NOK: Norwegian Kroner.

NPD: the Norwegian Petroleum Directorate.

NPV: Net Present Value.

o.e.: oil equivalents

OIP: oil in place.

GIP: gas in place.

Petroleum Initially-in-Place: Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas-in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment).

PIIP: See Petroleum Initially-in-Place.

Possible Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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.

Probable Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.

Production: Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.

Project: Represents the link between the petroleum accumulation and the decisionmaking process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimate.

Prospective Resources: Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Proved Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. 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. Often referred to as 1P, also as "Proven."

PDO: Plan for Development and Operation.

Recovery factor (RF): The ratio between the volumes of hydrocarbons produced and produceable from a reservoir, and the hydrocarbons originally in place.

Recoverable Resources: Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.

Reserve Replacement Ratio (RRR): The RRR is one measure of oil company performance. It shows the ratio of new reserves added to the inventory (from exploration/upgrading from resources/acquisitions) compared to oil produced. Ideally this ratio should be greater than 100 percent. Less than 100 % implies that the company is not able to replace what it is producing.

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 further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

Reservoir: A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.

Resources: The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional” (see Total Petroleum Initially-in-Place).

Resource Categories: Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in 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, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes).

Resources Classes: Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project’s estimated chance of reaching producing status.

RNB: Revised National Budget. The reporting for the RNB contributes basic data for the Government’s oil and environmental policy, the state and national budgets as well as a number of products from the Norwegian Petroleum Directorate (NPD), the Ministry of Petroleum and Energy (MPE), etc. Every autumn, all the operators report data related to the fields, discoveries, transport and land facilities which they operate.

Royalty: Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.

SEC: The US Securities and Exchange Commission. The primary US regulatory agency for the securities industry.

Sm³: standard cubic metre

Stochastic: Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.

Sub-Commercial: A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. 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. Discovered sub-commercial projects are classified as Contingent Resources.

Tcf: Trillion cubic feet

USD: US Dollar.