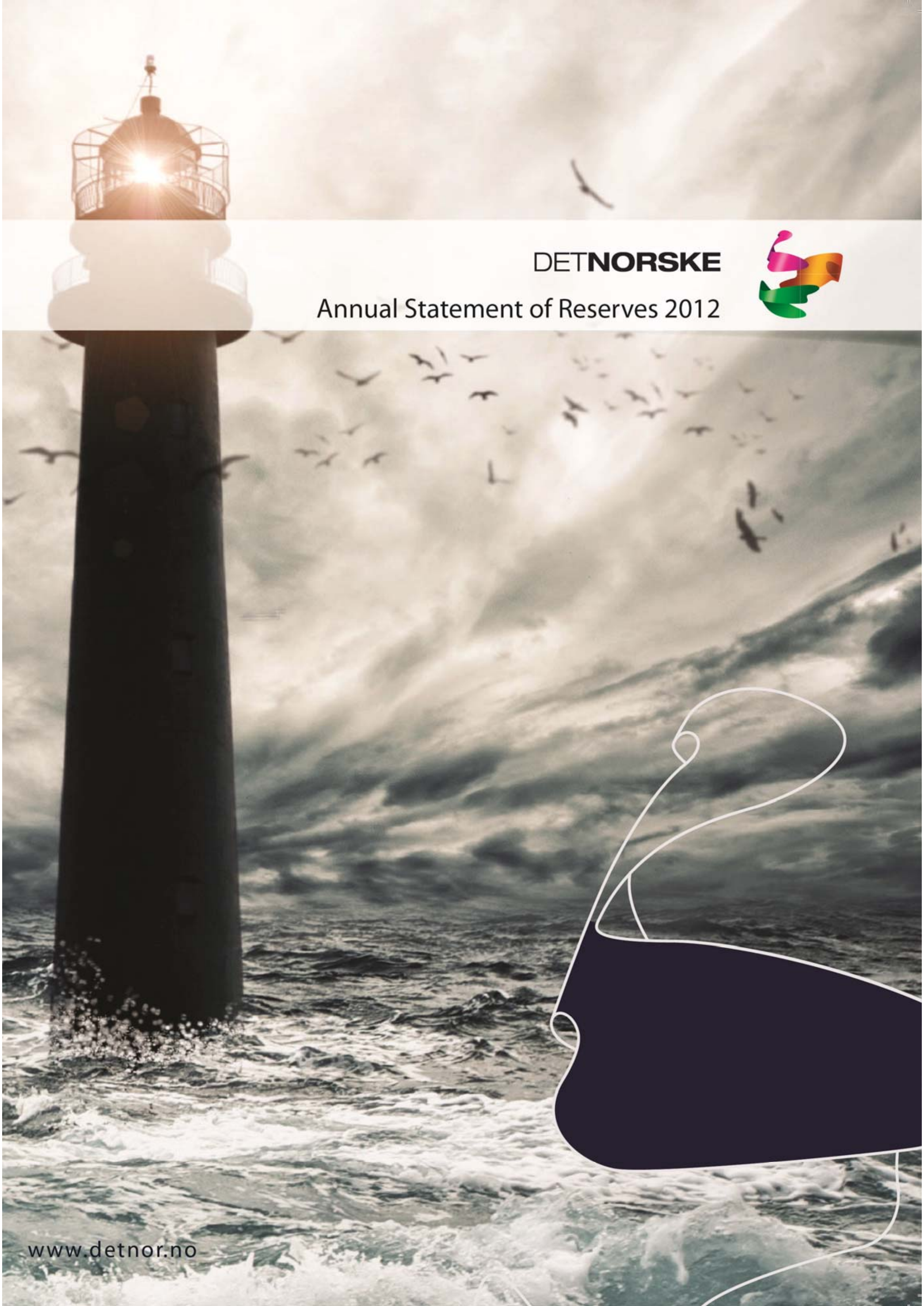

DETNORSKE

Annual Statement of Reserves 2012

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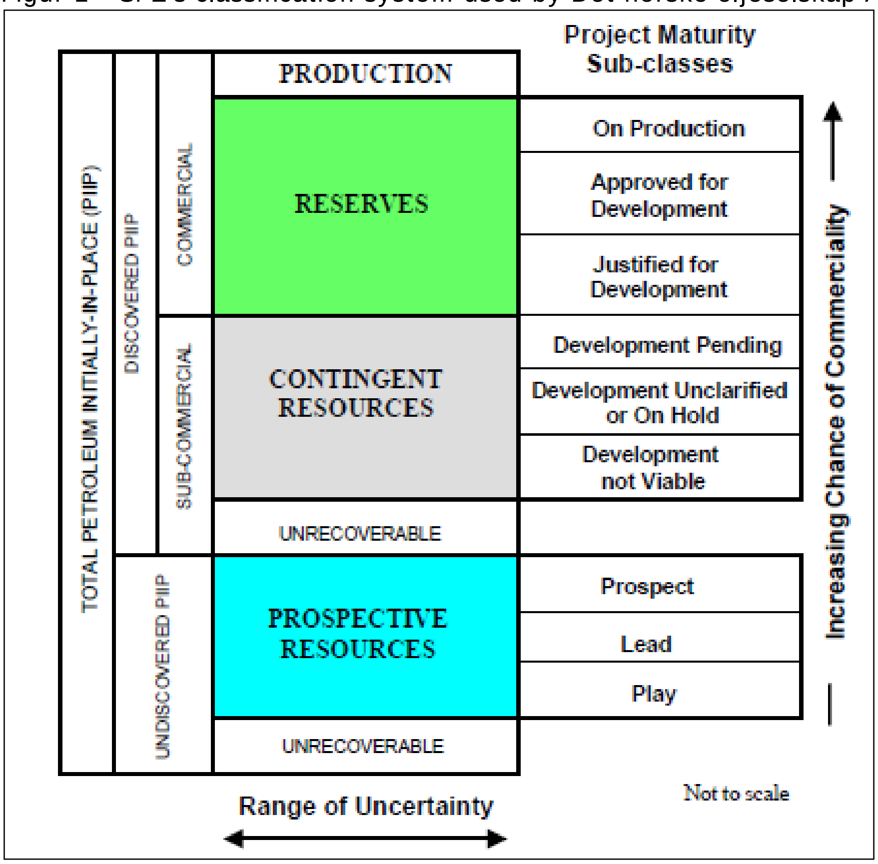
DETNORSKE

Table of Contents

1 Classification of Reserves and Contingent Resources

Det norske oljeselskap ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) "Petroleum Resources Management System". This classification system is consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework is illustrated in Figure 1.

Figur 1 - SPE's classification system used by Det norske oljeselskap ASA



2 Reserves, Developed and Non-developed

Det norske oljeselskap ASA has a working interest in eight fields/projects containing reserves, see Table 1. Out of these fields/projects, four are in the sub-class "On Production", two are in the sub-class "Approved for Development" and three are in the sub-class "Justified for Development". Note that Varg has reserves in both "On Production" and in "Justified for Development".

Sub-class "On Production":

- Varg – operated by Talisman, Det norske 5 percent
- Glitne – operated by Statoil, Det norske 10 percent
- Jotun operated by ExxonMobil, Det norske 7 percent
- Atla – operated by Total, Det norske 10 percent

Sub-class "Approved for Development":

- Jette – operated by Det norske, Det norske 70 percent
- Enoch – operated by Talisman, Det norske 2 percent

Sub-class "Justified for Development"

- Ivar Aasen project (former Draupne) – operated by Det norske, Det norske 35 percent
- Gina Krog (former Dagny) – operated by Statoil, Det norske 3.3 percent
- Varg gas project – operated by Talisman, Det norske 5 percent

Total net proven reserves (P90/1P) as of 31.12.2012 to Det norske are estimated at 42.5 million barrels of oil equivalents (mill. boe). Total net proven plus probable reserves (P50/2P) are estimated at 65.3 mill. boe. The split between liquid and gas and between the different subcategories can be seen in Table 1. Changes from 2011 are summarized in Table 2.

Table 1 – Reserves by field as of 31.12.2012

On Production	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents
As of 31.12.2012	(million barrels)	(bcm)	(million barrels)	%	(million barrels)	(million barrels)	(bcm)	(million barrels)	%	(million barrels)
Enoch Unit (Moved to AfD)				2 %	0,00				2 %	0,00
Glitne	0,00		0,00	10 %	0,00	0,04		0,04	10 %	0,004
Varg (including 2 infills)	5,58		5,58	5 %	0,28	7,88		7,88	5 %	0,39
Jotun Unit	2,73		2,73	7 %	0,19	3,03		3,03	7 %	0,21
Atla (moved from AfD)	0,80	0,59	4,50	10 %	0,45	1,60	1,32	9,90	10 %	0,99
Total					**0,92**					**1,60**
Approved for Development	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents
As of 31.12.2012	(million barrels)	(bcm)	(million barrels)	%	(million barrels)	(million barrels)	(bcm)	(million barrels)	%	(million barrels)
Enoch Unit(moved from OP)	1,71		1,71	2 %	0,03	2,61		2,61	2 %	0,05
Atla (moved to OP)				10 %	0,00				10 %	0,00
Glitne infill 2012 (dry well)				10 %	0,00				10 %	0,00
Jette (moved from JfD)	3,53	0,05	3,84	70 %	2,69	5,89	0,08	6,40	70 %	4,48
Total					**2,72**					**4,53**
Justified for Development	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents	Gross liquids	Gross gas	Gross oil equivalents	Interest	Net oil equivalents
As of 31.12.2012	(million barrels)	(bcm)	(million barrels)	%	(million barrels)	(million barrels)	(bcm)	(million barrels)	%	(million barrels)
Ivar Aasen	88,54	1,09	95,36	35 %	33,38	119,94	4,35	147,30	35 %	51,56
Jette (moved to AfD)				70 %	0,00				70 %	0,00
Gina Krog	73,00	11,77	146,99	3,3 %	4,85	101,00	16,62	205,50	3,3 %	6,78
Varg gas (new)	7,42	0,67	11,63	5 %	0,58	10,52	0,99	16,75	5 %	0,84
Total					**38,81**					**59,17**
Total Reserves 31.12.2012					**42,45**					**65,31**
Total Reserves 31.12.2011					**47,34**					**67,89**

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

Net attributed million barrels of oil equivalents (mboe)	**On production**		**Approved for Development**		**Justified for Development**		**Total**	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance as of 31.12.2011	0,24	0,80	7,17	12,95	39,93	54,14	47,34	67,89
Production	-0,54	-0,54	-	-	-	-	-0,54	-0,54
Acquisitions/disposals			-0,69	-1,14			-0,69	-1,14
Extensions and discoveries	-	-	-	-	-	-		
New developments	0,48	0,38	-0,35	-1,11	0,58	0,84	0,71	0,10
Revisions of previous estimates	0,74	0,96	-3,41	-6,16	-1,70	4,19	-4,37	-1,01
Balance as of 31.12.12	0,92	1,60	2,72	4,53	38,81	59,17	42,45	65,31
Delta	0,68	0,80	-4,45	-8,41	-1,12	5,03	-4,88	-2,59

3 Description of reserves

3.1 Enoch Unit

The Enoch Field in PL 048D straddles the Norwegian/UK border and is located in the North Sea, southwest of the Glitne Field. The field is operated by Talisman. Det norske holds a 2 percent working interst in the Enoch Unit, based on a 10 percent working interest in Norwegian PL 048D.

Enoch was discovered in 1991. The field development was approved in July 2005 and production from Enoch started in May 2007. Based on current estimates, the field will be shut down in 2017.

The reservoir, containing oil, is in Paleocene sandstones at a depth of approximately 2100 meters. The reservoir quality is variable.

Enoch is developed with a single, horizontal sub-sea well tied back to the Brae A platform in the UK, where the oil is processed and exported via the Forties pipeline network. The gas is sold to the Brae Field.

Enoch has been shut down since February 2012 due to mechanical problems with the X-mas tree. Work is ongoing to bring the field back on production and expected start-up is in Q1 2014. As a result of this, the reserves have been reclassified from “On Production” to “Approved for Development”.

There is an extra well slot available at Enoch and depending on reservoir performance, the field partners may decide to drill one additional production well.

3.2 Glitne

The Glitne Field in PL 048B is located in the North Sea, 40 kilometers north of the Sleipner area. The field is operated by Statoil. Det norske holds a 10 percent working interest in Glitne.

Glitne was discovered in 1995. The field development was approved in September 2000 and production from Glitne commenced in August 2001. Production from the field was shut in on February 24th 2013.

The reservoir consists of several separate sand lobes deposited as deep marine fans in the upper part of the Heimdal Formation of Paleocene age. The reservoir lies at a depth of approximately 2150 meters.

Glitne is developed with and produced by six sub-sea wells tied back to the floating, production, storage and offloading (FPSO) vessel “Petrojarl 1”. Oil is exported using shuttle tankers.

Production from the field is approximately 750 barrels of oil equivalents per day (boepd). An infill well, which was drilled during the spring 2012 was dry. As a result, the up-side potential describe in the ASR 2011 did not materialize.

The license has terminated the production contract with Teekay Production. Petrojarl 1 is scheduled to leave the field on 1st of May 2013.

3.3 Varg

The Varg Field in PL 038 is located in the North Sea, south of Sleipner Øst, and is operated by Talisman. Det norske holds a 5 percent working interest in Varg.

Varg was discovered in 1994. The field development was approved in May 1996 and Varg came into production in December 1998.

The reservoir is in Upper Jurassic sandstones at a depth of approximately 2700 meters. The structure is segmented and includes several isolated compartments with varying reservoir properties.

Varg is developed with the FPSO vessel “Petrojarl Varg”, which is connected to the wellhead platform, Varg A. Oil is exported using shuttle tankers. The field has currently three wells on production (as in 2011).

Total production at Varg is approximately 7000 boepd by year-end 2012. The producing wells are performing in line with prognosis.

Two new wells have been drilled and will start producing in early 2013. The estimated production from these wells is classified as “On Production” and the volumes are reported together with the production from the three wells currently producing. The reserves from these two infill wells were reported as “Justified for Development” in the 2012 Annual Statement of Reserves. The license has decided to drill a third infill well and the estimated production from this well is classified as contingent resources.

The gas blow-down scenario described in the 2011 Annual Statement of Reserves has been sanctioned within the license and the estimated production is upgraded compared to the 2011 report; from “Development Pending” to “Development Justified”. One gas producer is planned and a new gas export line will be installed between the Petrojarl Varg FPSO and the subsea facilities on the nearby Rev gas field. The Varg production will together with the Rev production be piped to the Armada platform on the UK shelf.

The reserve estimates from the producing and future wells are based on decline analysis together with detailed dynamic simulations. Also, the gas reserves from the gas blow-down project are estimated using detailed reservoir simulation models.

3.4 Jotun

The Jotun Field (PL 027B, PL 103B) is located in the North Sea and is operated by ExxonMobil. Det norske holds a 7 percent working interest in the Jotun Unit.

Jotun was discovered in 1994. The field development was approved in June 1997 and Jotun started producing in October 1999. Based on current plans, the field is expected to continue producing through 2017.

The field comprises three structures of Paleocene age. The reservoirs are deposited in a sub-marine fan system and lie at a depth of about 2000 meters.

Jotun is developed with an integrated well head platform (Jotun B) and an FPSO (Jotun A). The field has currently nine wells on production. The oil is shuttled to the Slagen refinery, while the gas is exported into Statpipe.

The field is producing according to prognosis and the gross production is currently approximately 3200 boepd. Jotun earns tariff income from other fields in addition to its own production, making the field more profitable than what the production figures alone indicate.

Proved plus probable reserves (P50/2P) include expected volume from existing wells, assuming no new wells being drilled and abandonment of the field at the end of 2017. 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.

Note that Det norske is currently developing the small Jette oil discovery as a subsea tie back to Jotun. Production start is expected in April 2013.

3.5 Atla

Atla is located in PL 102C, in the southern part of the North Sea, about 20 kilometres northeast of the Heimdal Field. Total is the operator of Atla and Det norske holds a 10 percent working interest in the field.

The field was discovered in 2010. The field development was approved in November 2011 and the field started producing in October 2012.

Atla contains gas/condensate in sandstones of the Middle Jurassic Brent Group, at a depth of about 2700 meters.

The field development, consisting of one subsea well tied back via the Skirne Field to the Heimdal platform. The gas is transported in the Gasled system to the UK and Continental Europe. The condensate is exported via Brae into the Forties system.

The average initial production from Atla in 2012 was 2294 boepd.

Atla was in 2011 classified as reserves and reported as “Development Approved”. As production from Atla has started, the reserves have been upgraded to “On Production”.

3.6 Jette

The Jette Field in PL 027D, PL 169C and PL 504, is located near the Jotun Field in the North Sea. Det norske oljeselskap ASA is operator and holds a 70 percent working interest.

The field was discovered in 2009. The field development was approved in February 2012, and the plan is to start producing from the field in April 2013. Current estimates are based on production through 2017.

Jette contains oil in Paleocene sandstones at a depth of approximately 2100 meters.

The field development comprises a subsea template with two production wells, tied back to the Jotun A wellhead platform. Oil will be processed to sales specification and stored on Jotun A before being shuttled. The associated dry gas will be exported to the Statpipe system.

Jette was in 2011 classified as reserves and reported as “Development Justified”. As the PDO was approved by the authorities, the reserves are upgraded to “Development Approved”.

There is a reduction in reserves compared to what was reported in the PDO and certified in 2011 because of problems with completion of the production wells. Initially the two production wells were planned to produce from two different reservoirs. However, due to problems with installation of sand screens, both two well slots have been redesigned to drain the southern reserves only. As a result, production from the northern segment has been deferred and is pending a possible future drilling campaign.

The basis for the revised reserve estimates are mainly based on an updated PDO simulation model. Also note that the reserve numbers reported in Table 1 include a minor compensation element to the Jotun Group and that the actual production is estimated to be somewhat higher. Since the 2011 reporting, Det norske has reduced its share in the field from 88 percent to 70 percent.

3.7 Ivar Aasen

The Ivar Aasen development in PL 001B, PL 028B and PL 242, is located in the North Sea on the Utsira High. The field is operated by Det norske oljeselskap. Det norske holds a 35 percent working interest in the field.

Ivar Aasen was discovered in 2008. The Plan for Development and Operations (PDO) was submitted to Norwegian authorities in December 2012.

Ivar Aasen holds oil and gas in the Middle Jurassic Sleipner Formation and the Upper Triassic Skagerak Formation, at a depth of approximately 2400 meters. The 25/10-8 Hanz discovery and the 16/1-7 West Cable discoveries are both part of the Ivar Aasen development.

Ivar Aasen is planned developed with a steel jacket platform with living quarters and processing facilities. The well stream will be partly processed on the platform before transported to the Edvard Grieg installation for final stabilization and export. The Ivar Aasen and West Cable wells will be drilled from dry wellheads on the platform utilizing a jack-up rig. The Hanz discovery will be developed with two subsea completed wells tied back to the Ivar Aasen platform. The development of Ivar Aasen and West Cable constitutes phase 1 in the development, while the Hanz development constitutes phase 2 of the development.

The reserves reported within this report are estimates at the time for the DG 2 decision. These reserve estimates have been certified by AGR Petroleum Services, ref chapter 5. New assessment of the reserve estimates were performed prior to the PDO submittal, which gave only marginal differences compared to the DG 2 reserve base.

In late 2012, the adjacent PL 457 to the east, drilled an appraisal well proving an extension of the Ivar Aasen field into PL 457. The results from the well were positive, with a thicker reservoir section, better reservoir quality and a deeper oil-water contact than expected. In addition no gas cap was penetrated. The well results came in too late to impact the PDO reserve estimates. A small part of Ivar Aasen may also extend into the neighbouring PL 338 to the south. Commercial negotiations have been initiated with both PL457 and PL 338 with the objective to regulate these circumstances.

The DG 2 reserve estimates which have been certified by AGR Petroleum Services include the minor parts extending into the PL 457 and potentially PL 338.

3.8 Gina Krog (former Dagny)

The Gina Krog gas and oil field in PL 303, PL 048, PL 029B and PL 029C, is located about 30 kilometres north of Sleipner A in the North Sea. Statoil is the field operator. Det norske holds a 3.3 percent working interest in the Gina Krog Unit, based on a 20 percent working interest in PL 029B.

The field was discovered in 1974. A PDO for Gina Krog was submitted to Norwegian authorities in December 2012.

Gina Krog holds oil and gas in the Middle Jurassic Hugin Formation at a depth of approximately 3300 to 3900 meters. The reserves are classified as “Development Justified”.

In December 2011 a fixed platform was selected as development concept. Gas from Gina Krog will be exported through a tie-back to the infrastructure on Sleipner East, while offshore loading into shuttle tankers is decided for the oil.

A unitization agreement was signed prior to the PDO submittal, which gives Det norske 3.3 percent working interest in the unitized area. This should be compared to the pre unit cost sharing agreement, which gave Det norske a 2.0 percent working interest and which has been assumed in previous reserve reports. Note that the unitization result is pending final approval from the MPE.

The reserves reported within this report are the reserve estimates at the time for the DG 2 decision in 2011. These reserve estimates have been certified by AGR Petroleum Services, ref chapter 5. New assessment of the reserve estimates were performed prior to the PDO submittal which gave marginally higher reserve estimates compared to the DG 2 reserve base.

4 Contingent Resources

Det norske oljeselskap ASA has interests in 23 discoveries/projects classified as contingent resources, and a complete list is provided below.

Six of these discoveries/projects are in the planning phase ("Development Pending"); Frøy, Storklakken, Øst Frigg Gamma/Delta, Fulla, Krafla and Johan Sverdrup.

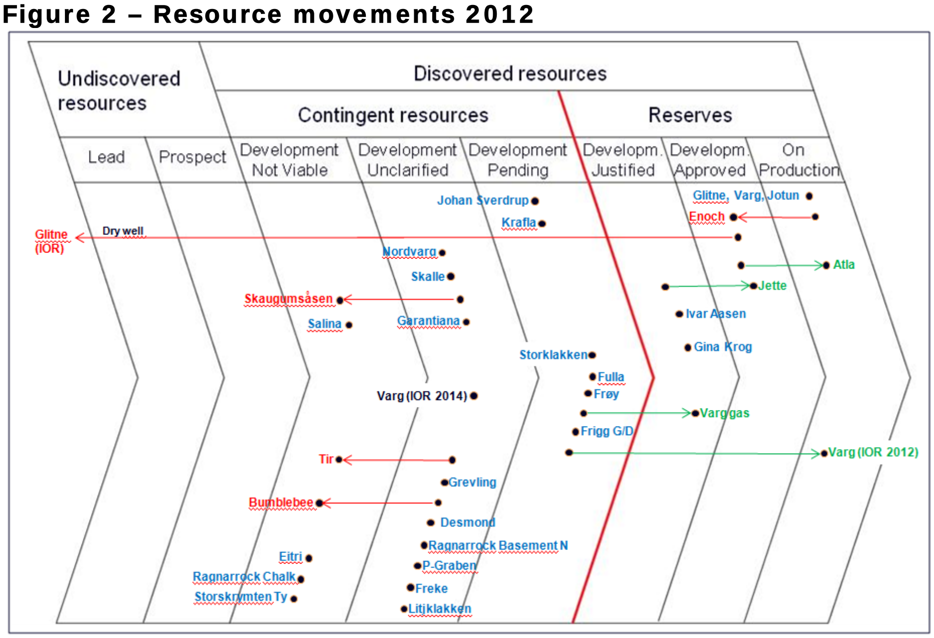
The two Varg IOR projects reported as "Development Pending" in 2012 are reclassified as Reserves Justified for Development".

Ten discoveries/projects are classified as "Development Unclarified or on Hold"; Varg Infill 2014, Grevling, Desmond, Ragnarrock Basement, Freke, P-Graben, Litjklakken, Norvarg, Skalle and Garantiana. The latter is a discovery made during 2012. Compared to the 2011 reserve and resources reporting the three discoveries Skaugumsåsen, Tir and Bumblebee have been downgraded from "Development Unclarified" to "Development Not Viable".

Seven discoveries are classified as non-commercial ("Development not Viable"); Storskrymten, Eitri, Ragnarrock Chalk, Skaugumsåsen, Bumblebee, Tir and Salina. The latter being a 2012 discovery.

Figure 2 illustrates resource movements for fields and discoveries in 2012. Blue text has been assigned to the names were there has not been any movement between sub classes, red text has been assigned to names of fields that have moved backwards in the maturity matrix, while green text has been assigned to names were the discovery/field has moved forward in the maturity matrix.

Figure 2 – Resource movements 2012



Det norske participated in three discoveries in 2012; the PL 265 Geitungen discovery being the most important, the PL 554 Garantiana discovery and the PL 533 Salina discovery. The Geitungen discovery is an extension of the Johan Sverdrup discovery and is included as a part of that. The Salina discovery well proved only non commercial amounts of gas and the discovery is classified as “Development not Viable”. The Garantiana discovery is assumed to have a commercial potential, however no field development planning has yet taken place and the discovery is classified as “Development Unclarified”.

The Varg gas blow down project has been sanctioned by the partnership and is reclassified from “Development Pending” to “Development Justified”. The Varg Infill Well 2012 campaign has been moved from “Development Pending” to “On Production” and all reserves from these two wells are reported together with already producing wells. The Glitne IOR well that reported as Development Approved in 2011 came in dry and has thus been removed.

Note also that the Tir and Bumblebee discoveries have been downgraded from “Development Unclarified” to “Development not Viable”.

The following is a complete list of all discoveries with contingent resources:

“Development Pending”:

- PL 364 (Well 25/5-1) Frøy - operated by Det norske 50% share
- PL 035B and PL 362 (Well 30/11-7) Fulla – operated by Statoil, Det norske 15% share
- PL 442 (Well 25/2-17) Frigg Gamma/Delta - operated by Statoil, Det norske 20% share
- PL 265 (Well 16/2-8) Johan Sverdrup – operated by Statoil, Det norske 20% share
- PL 272/035 (Well 30/11-8S) Krafla – operated by Statoil, Det norske 25% share
- PL 460 (Well 25/1-11) Storklakken - operated by Det norske (100% share)

Development Unclarified or on Hold”:

- PL 460 (Well 25/1-9) Litjklakken - operated by Det norske (100% share)
- PL 038D (Well 15/12-23) Grevling – operated by Talisman, Det norske 30% share
- PL038 Varg Infill 2014 – Operated by Talisman, Det norske 5 % share
- PL 332 (Well 2/2-2) Desmond - operated by Talisman, Det norske 40% share
- PL 265 (Well 16/2-3) Ragnarrock Basement North - operated by Statoil, Det norske 20% share
- PL 265 (Well 16/2-5) P-Graben - operated by Statoil, Det norske 20% share
- PL 029B (Well 15/6-10) Freke – operated by Statoil, Det norske 20% share
- PL 535 (Well 7522/3-1) Norvarg – operated by Total, Det norske 20% share
- PL 554 (Well 34/6-2S) Garantiana – operated by Total, Det norske 20% share
- PL 438 (Well 7120/2-3S) Skalle – operated by Lundin, Det norske 10% share

Development not Viable:

- PL 337 (Well 15/12-18S) Storskrymten – operated by Det norske (45% share)
- PL 027D (Well 25/8-16S) Eitri – operated by ExxonMobil, Det norske 60% share
- PL 265 (Well 16/2-3) Ragnarrock Chalk- operated by Statoil, Det norske 20% share
- PL 482 (well 6508/1-2) Skaugumsåsen – operated by Det norske 65 % share
- PL 102C (Well 25/5-5) Tir – operated by Total, Det norske 10% share
- PL 332 (Well 2/2-5) Bumblebee - operated by Talisman, Det norske 40% share
- PL 533 (Well 7220/10-1) Salina - operated by Eni, Det norske 20% share

Det norske’s ”Development Pending” contingent resources (oil and gas resources where field development is in the planning phase) have been certified by AGR Petroleum Services AS in December 2012 and amount to between 308 and 487 million barrels of recoverable oil equivalents. These contingent resources arise from seven discoveries, of which around 80% from the Johan Sverdrup Field (Det norske's share of PL 265).

The discovery Johan Sverdrup (previously Aldous/Avaldsnes) made in 2010-11 covers both PL 265 and PL 501. The field contains undersaturated oil. In PL 265, where Det norske holds a 20% working interest, the reservoir is excellent. A pre unit agreement has been established with Statoil as working operator for the development phase. Current field development plan aims for first oil in late 2018.

The Krafla discoveries (Krafla Main and Krafla West) made in 2011 contain both oil and gas. Several development solutions are currently being investigated by the Operator Statoil.

The Fulla discovery made in 2009 contains gas/condensate at high pressure and temperature (HPHT). Tie-back is being considered to the Heimdal or Bruce (UK) fields. Centrica is the operator.

The East Frigg Gamma and Delta discoveries contain relatively heavy oil with a significant gas cap. The fields are being considered as part of a potential area development. Centrica is the operator.

The Frøy field operated by Det norske contains oil. Frøy is a redevelopment project being considered part of the above mentioned area development.

The Storklakken discovery operated by Det norske contains oil. The discovery will most likely be developed as a one well subsea tie-back, either to a future Frøy installation or to a future area developmet installation. Storklakken is operated by Det norske.

Limited field development evaluations have been carried out for Det norske's discoveries in the category "Development Unclarified or On Hold", thus timing and recoverable volumes are very uncertain. The sum of the low estimates amounts to approximately 35 mill. boe. The sum of the high estimates amounts to approximately 170 mill. boe.

5 Management's Discussion and Analysis

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 group of professionals, headed by a reservoir engineer with more than 20 years of experience in such assessments.

Additionally, all volumes within the reserve category (except for the Glitne and Enoch Fields) have been certified by an independent third party consultancy (AGR Petroleum Services AS). These are the producing fields Varg, Jotun, Atla and the still not developed fields Ivar Aasen, Gina Krog and Jette. In addition AGR has certified the "Development Pending" part of contingent resources reported for Johan Sverdrup (Det norske's part of PL265), Krafla, Frøy, Fulla, Frigg Gamma Delta and Storklakken.

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 for the various fields 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 percent nominal after tax. The company has used a long term inflation assumption of 2.5 percent, and a long term exchange rate of 6.0 NOK/USD. Oil prices are based on the Company's basic assumptions for investment analysis, using a fixed oil price of 105 USD/bbl (real 2012 terms).

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 fully clarify all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Therefore there is a remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also 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.

Erik Haugane

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 Sm^3 of oil = 1.0 Sm^3 o.e.
1 Sm^3 of condensate = 1.0 Sm^3 o.e.
1000 Sm^3 of gas = 1.0 Sm^3 o.e.
1 tonne of NGL = 1.9 Sm^3 NGL = 1.9 Sm^3 o.e.

Gas:

1 cubic foot	1 000.00 Btu
1 cubc 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
bbl: barrel (of oil)
boe: barrel of oil equivalent of natural gas and crude oil
boepd: barrel of oil equivalent per day.
CO: carbon monoxide
CO_2: 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.
m^3: 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 Gasin-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.
Sm^3: 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.