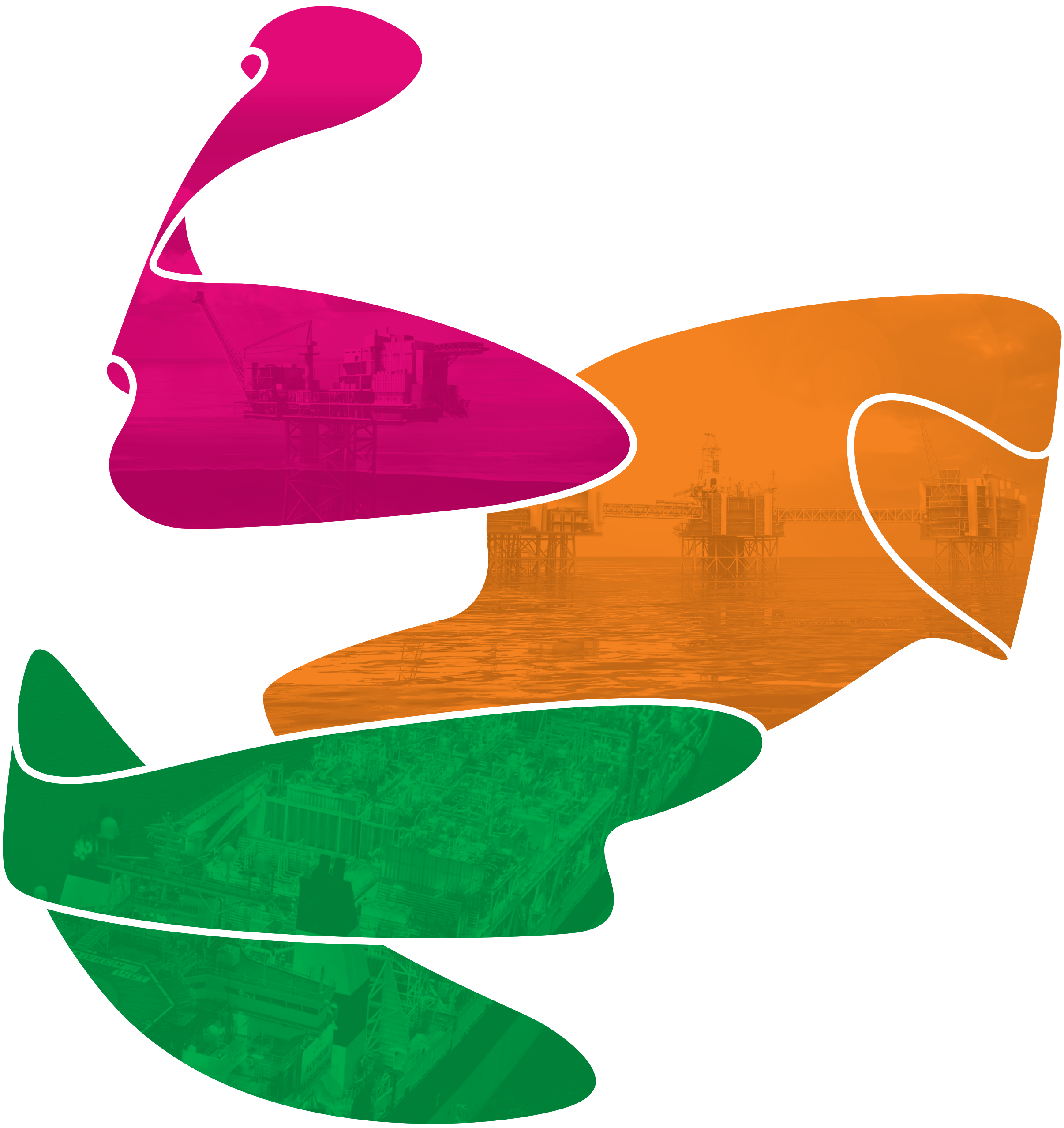
ANNUAL STATEMENT OF RESERVES 2014

DET NORSKE OLJESELSKAP ASA



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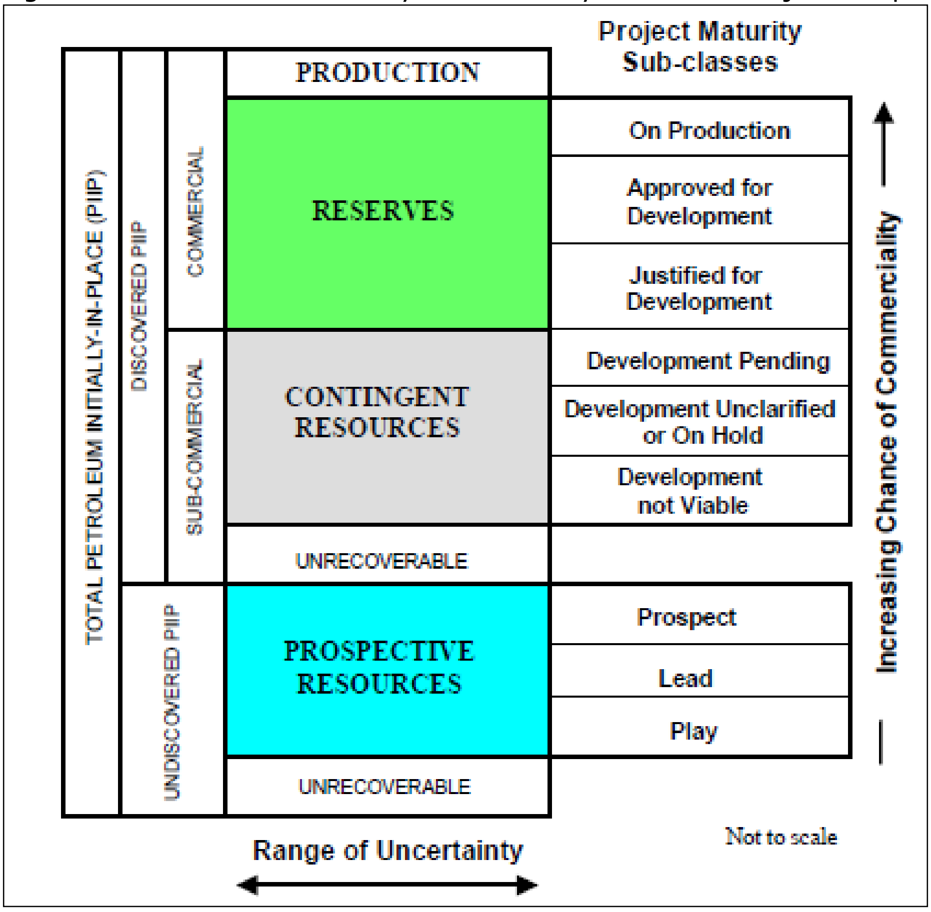
1 Classification of Reserves and Contingent Resources

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 of the classification system 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 14 fields/projects containing reserves, see Table 1. Out of these fields/projects, eight are in the sub-class "On Production" and six are in the sub-class "Approved for Development". Note that parts of the Alvheim Field are classified as "Justified for Production". The Reason being that these reserves represent a planned infill well drilling campaign. Note also that Boa is a part of the Alvheim Field. The reason that this part is reported separately is that this part extends into the UK Continental shelf. An unitisation agreement with the UK parties has resulted in a net share of 57.622 percent (65*0.8865) to Det norske.

Sub-class "On Production":

- Alvheim - operated by Det norske, Det norske 65 percent
- Boa (Part of Alvheim) - operated by Det norske, Det norske 57.622 percent
- Volund - operated by Det norske, Det norske 65 percent
- Vilje - operated by Det norske, Det norske 46.907 percent

- Atla – operated by Total, Det norske 10 percent
- Jette – operated by Det norske, Det norske 70 percent
- Varg – operated by Talisman, Det norske 5 percent
- Jotun operated by ExxonMobil, Det norske 7 percent

Sub-class “Approved for Development”:

- Ivar Aasen Unit– operated by Det norske, Det norske 34.7862 percent
- Bøyla – operated by Det norske, Det norske 65 percent
- Gina Krog – operated by Statoil, Det norske 3.3 percent
- Hanz – operated by Det norske, Det norske 35 percent
- Viper/Kobra – operated by Det norske, Det norske 65 percent
- Enoch – operated by Talisman, Det norske 2 percent

Sub-class “Justified for Development”:

- Alvheim Kameleon Phase 3 – operated by Det norske, Det norske 65 percent
- Alvheim East Kam 4 – operated by Det norske, Det norske 65 percent
- Alvheim Kneler 1 – operated by Det norske, Det norske 65 percent
- Alvheim Boa Kam North – operated by Det norske, Det norske 62.4178 percent

Total net proven reserves (P90/1P) as of 31.12.2014 to Det norske are estimated at 142 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 206 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories can be seen in Table 1.

Changes from 2013 are summarized in Table 2. The main reason for increased net reserve estimate is the acquisition of Marathon Oil Norge AS. The reserves associated with this acquisition represent 84% and 90 % of the reserve increase for proven (1P/P90) and proven plus probable reserves (2P/P50) respectively.

In 2014, parts of the former Ivar Aasen Field have been unitized. In the 2013 report, the Ivar Aasen Field included the Ivar Aasen (Former Draupne) discovery, the West Cable discovery and the Hanz discovery. In this year’s report Hanz is reported separately. The reason being that the PL001B licence (Ivar Aasen discovery) in 2014 has been unitized with PL457 and PL338 BS. Also the West Cable (PL242) was included in the unitization agreement forming the Ivar Aasen unit with a net share to Det norske of 34.7862 percent.

The future oil price assumption for the reserves given in Table 1 below is 85 USD/bbl. Average oil price in the period 01.10.2013 to 01.10.2014 was 105 USD/bbl. A sensitivity with a higher oil price of 105 USD/bbl had only minor impact on net total reserves to Det norske

Table 1 – Reserves by field as of 31.12.2014

On Production	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents	Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents
As of 31.12.2014	(%)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)
Varg	5,0 %	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Jotun	7,0 %	0,00			0,00	0,00	0,00			0,00	0,00
Atla	10,0 %	0,45		0,70	4,85	0,48	0,51		0,79	5,49	0,55
Jette	70,0 %	0,28			0,28	0,20	0,36			0,36	0,25
Alvheim	65,0 %	39,39		0,26	41,05	26,68	62,45		1,19	69,95	45,47
Boa	57,6 %	13,51		0,24	14,99	8,64	18,84		0,33	20,93	12,06
Vilje	46,9 %	12,89			12,89	6,05	22,37			22,37	10,49
Volund	65,0 %	11,42		0,10	12,04	7,82	16,76		0,20	18,03	11,72
Total						**49,87**					**80,54**
Approved for Development	**Interest**	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
	%	Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents	Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents
As of 31.12.2014	(%)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)
Enoch Unit	2,0 %	1,71			1,71	0,03	2,61			2,61	0,05
Ivar Aasen	34,8 %	110,82	0,80	4,45	148,38	51,62	144,59	0,85	4,71	184,42	64,15
Hanz	35,0 %	12,11	0,05	0,26	14,34	5,02	16,14	0,07	0,36	19,28	6,75
Gina Krog	3,3 %	82,33	2,61	9,59	173,84	5,74	106,63	3,30	12,43	224,17	7,40
Viper/Kobra	65,0 %	4,60		0,07	5,04	3,28	7,82		0,12	8,58	5,58
Bøyla	65,0 %	11,70		0,09	12,27	7,98	21,32		0,19	22,54	14,65
Total						**73,66**					**98,58**
Justified for Development	**Interest**	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
		Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents	Gross oil/cond.	Gross NGL	Gross gas	Gross oil equivalents	Net oil equivalents
As of 31.12.2014	(%)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)	(Mbbl)	(Mton)	(GSm3)	(Mbbl)	(Mbbl)
Alvheim Kam Phase 3	65,0 %	0,00		3,01	18,96	12,32	0,00		3,30	20,73	13,48
Alvheim East Kam L4	65,0 %	2,32		0,06	2,67	1,73	4,07		0,10	4,67	3,04
Alvheim Kneler 1	65,0 %	2,30		0,03	2,47	1,60	5,18		0,06	5,55	3,61
Alvheim Boa Kam North	62,4 %	3,81		0,06	4,22	2,63	9,06		0,15	10,02	6,26
Total						**18,29**					**26,38**
Total Reserves 31.12.2014						**141,83**					**205,50**
Total Reserves 31.12.2013						**48,53**					**65,76**

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

Net attributed million barrels of oil equivalents (mmboe)	On Production		Approved for Dev.		Justified for Dev.		Total	
	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2013	**1,4**	**3,6**	**47,2**	**62,2**	**0,0**	**0,0**	**48,6**	**65,8**
Production	-4,1	-4,1	0,0	0,0	0,0	0,0	-4,1	-4,1
Acquisitions/Disposals	49,2	79,7	11,3	20,2	18,3	26,4	78,7	126,4
Extensions and discoveries	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
New developments	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Revisions of previous estimates	3,4	1,3	15,2	16,1	0,0	0,0	18,6	17,4
Balance as of 31.12.2014	**49,9**	**80,5**	**73,7**	**98,6**	**18,3**	**26,4**	**141,8**	**205,5**
Delta	**48,5**	**77,0**	**26,5**	**36,3**	**18,3**	**26,4**	**93,3**	**139,7**

3 Description of reserves

3.1 Producing assets

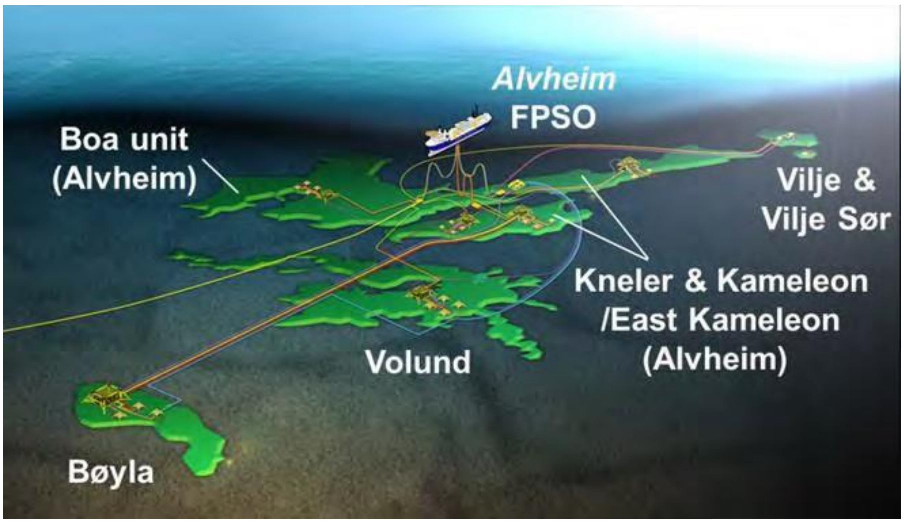
3.1.1 Alvheim (PL036C, PL088BS, PL203)

Alvheim is an oil and gas field located in the Norwegian sector of the Northern North Sea in a water depth between 120-130 meters. The field is located in Blocks 24/6, 24/9, 25/4 and 25/7 and is comprised of the producing Alvheim field (Boa, Kneler, and Kameleon/East Kameleon structures), Viber-Kobra, and Gekko discoveries (the "Alvheim Area Fields"). The productive horizon for the Alvheim fields is the Middle to Late Palaeocene Heimdal Formation sandstone which exists at a depth of approximately 2,100 meters. Alvheim was developed using a floating production, storage and offloading FPSO vessel (the "Alvheim FPSO"). The development provides for the transport of oil by shuttle tanker and transportation of gas to the SAGE system. The Alvheim FPSO is characterized by high regularity, over 98% uptime (excluding planned down-time for maintenance).

First production for the Alvheim field was in June 2008. The Alvheim Area Fields have seen significant year-on-year increases in the estimated recoverable volumes of oil and gas since the initial development of the Alvheim field. Recoverable oil has increased as a function of greater in-place volumes than previously estimated, development of satellite fields, additional horizontal and multi-lateral wells, and better than anticipated reservoir performance. Furthermore, improved reliability combined with optimization work has increased the production capacity of the Alvheim FPSO to about 150,000 boepd up from the original design of 120,000 boepd. Total 2014 production including Boa amounted to 23.7 million barrels of oil equivalents. The cessation of production of the Alvheim field is estimated to 2031, with subsequent abandonment between 2031 and 2033.

Det norske is the operator of the Alvheim Area Fields with a 65% working interest. The other partners are ConocoPhillips Skandinavia AS holding a 20% interest and Lundin Norway AS holding a 15% interest.

Below is a location map of the Alvheim Area Fields:



The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitized with Maersk Oil & Gas and Verus Petroleum, who are the owners on the UK side. Det norske's interest in the Boa unit is 57.62%.

3.1.2 Vilje (PL036D)

The Vilje field is located North East of Alvheim at a water depth of 120 meters. The productive horizon for the Vilje field is the Middle to Late Palaeocene Heimdal Formation sandstone at a depth of approximately 2,100 meters. The field is tied back to the Alvheim FPSO through a 19 km pipeline. Production commenced in 2008. A third production well, Vilje South, is developed as a subsea tieback to the Vilje subsea facilities. Production commenced in April 2014.

Total production in 2014 amounted to 6.8 million barrels of oil equivalents. Production from the Vilje field is expected to cease in 2030, with subsequent abandonment scheduled to take place between 2031 to 2033, which coincides with the expected cessation of production from the Alvheim area.

Det norske holds a 46.904% interest in the license and serves as operator. The other license partners are Statoil Petroleum AS holding a 28.853% interest and Total E&P Norge AS with a 24.243% interest.

3.1.3 Volund (PL150)

The Volund field is located approximately eight km south of Alvheim, and was the second field developed as a subsea tieback to Alvheim. The Volund field, comprising of four production wells and one water injection well, started producing in 2009 and was utilized as a swing producer when the capacity at the Alvheim FPSO allowed it. The field was opened for regular production in 2010. The Volund reservoir is a large-scale injective feature, formed by sands of the Palaeocene Hermod Formation. These have become remobilized and subsequently injected into the overlying stratigraphy during the Early Eocene, creating steeply dipping “wings” of injected sand dykes from flat sand sills, at depths from approximately 1,800 meters to 2,000 meters.

Total production in 2014 amounted to 7.5 million barrels of oil equivalents. Cessation of production from the Volund field is expected in 2028.

Det norske holds a 65% interest in Volund and serve as operator, while Lundin Norway AS holds the remaining 35% interest.

3.1.4 Atla (PL102C)

Atla is a small gas/condensate field in the central part of the North Sea in a water depth of 119 meters. The reservoir contains gas/condensate in sandstones in the Brent Group of Middle Jurassic age at a depth of about 2,700 meters. The field produces with a subsea installation tied back to the existing pipeline between the Heimdal and Skirne fields. Production started two years after the discovery in October 2010.

Total production in 2014 amounted to 1.9 million barrels of oil equivalents. It is estimated that the field will continue to produce until 2017.

Det norske holds a 10% interest in the license. Total E&P Norge AS is the operator holding a 40% interest while Petoro AS holds a 30% interest and Lotos Exploration and Production Norge AS holds the remaining 20% interest.

3.1.5 Jette (PL027D, PL169C, PL504)

Jette is a small oil field in the central part of the North Sea in a water depth of 127 meters. The reservoir consists of a submarine fan system in the Heimdal Formation of Late Palaeocene age, and lies at a depth of approximately 2,200 meters. The field has been developed with a subsea installation tied back to the Jotun B platform. A number of modifications to Jotun B, in addition to minor modifications on Jotun A, were required in order to tie the two fields together. The chosen development concept enables future tie-up to additional wells. The well stream from Jette is mixed with the well stream from Jotun on Jotun B and transported to Jotun A for further processing, storage and export.

The field is developed with two producers. Since start-up the field has experienced increasing water cut and a steady decline in production and current reserve estimates assumes an economic cut-off 31.12.2015. The agreement with the Jotun unit includes a tariff payment regime until 31.12.2015. From this date the current agreement assumes OPEX-split between the units. Det norske is seeking a renegotiated agreement and a possible prolonged economic lifetime on Jette will thus depend on such agreement. Also the production level and possible more third party tie-ins to Jotun may also prolong the Jette economic lifetime.

Total production in 2014 amounted to 0.64 million barrels of oil equivalents.

Det norskes's interest in the Jette unit is 70% while Petoro AS holds the remaining 30% interest.

3.1.6 Jotun (PL027B, PL103B)

Jotun is an oil field located in the central part of the North Sea in a water depth of approximately 126 meters. The Jotun unit comprises three structures; the easternmost structure has a small gas cap. The reservoirs consist of sandstones in the Heimdal Formation of Palaeocene age. The reservoirs, which consist of deposits of a submarine fan system, are at a depth of about 2,000 meters. To the west, the reservoir quality is good, while the shale content increases towards the east.

The Jotun installations comprise of an FPSO, Jotun A, and a wellhead platform, Jotun B. Production commenced in 1999 and is now in the tail-end phase. After the Jette unit was tied back to Jotun in 2013, the lifetime of Jotun was assumed to be extended. However, due to the new prognosis for the existing Jette wells that show significantly lower production than previous assessments, Jotun is actively seeking third-party volume opportunities. Even though the field most likely will be on production long after 31.12.2015, Det norske has not included any reserves from Jotun in the company's reserve base as of 31.12.2014. The reason for this is that both the proven and proven plus probable production profiles indicates negative cash flow as of 31.12.2014. This is in accordance with the SPE's "Petroleum Recourse Management System".

Det norske's interest in the unit is 7%. The operator is ExxonMobil Exploration & Production Norway AS with a 45% interest. The other licensees are Dana Petroleum Norway AS which holds a 45% interest and Faroe Petroleum Norge AS with a 3% interest.

Total production in 2014 amounted to 0.8 million barrels of oil equivalents.

3.1.7 Varg (PL038)

The Varg field is an oil field located in the central part of the North Sea at a water depth of 84 meters. The reservoir is in Upper Jurassic sandstones at a depth of approximately 2,700 meters. The structure is segmented and includes several isolated compartments with varying reservoir properties.

Varg is developed with a wellhead platform, Varg A, and an FPSO, Petrojarl Varg. Varg A is normally unmanned. The wellhead platform and the FPSO are connected through flexible pipelines for oil production, water and gas injection and umbilical for power supply and control. The oil is offloaded from the FPSO to shuttle tankers via a discharging system located aft on the FPSO.

All gas were initially re-injected into the reservoir. After 15 years of oil production, gas production was started in 2013, which has contributed to extend the lifetime for the Varg facilities. Varg is very much on tail end production. The current OPEX level and estimated production forecasts gives no proven (1P/P90) reserves after 31.12.2014. The proven plus probable reserve estimate (2P/P50) assumes an economic cut-off 31.12.2015.

Total production in 2014 amounted to 3.5 million barrels of oil equivalents.

Det norske holds a 5% interest in the license, while the operator Talisman Energy Norge holds 65%. The remaining 30% is held by Petoro AS.

3.2 Development Projects

3.2.1 Ivar Aasen Unit and Hanz (PL001B, PL028B, PL242, PL338BS, PL457)

The Ivar Aasen Field is an oil field situated west of the Johan Sverdrup discovery in the North Sea at a water depth of 110 meters. The reservoir consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak Formations. The reservoir contains oil at a depth of approximately 2,400 meters. Parts of the reservoir have an overlying gas cap.

The PDO was approved in June 2013. First oil is planned in the fourth quarter of 2016 and the anticipated economic life is 20 years. The development of the Ivar Aasen field is so far on time and on budget.

At the end of 2013, the Ivar Aasen field (Ivar Aasen, West acabel and Hanz discoveries) had certified 2P reserves of 158 million barrels of oil equivalents excluding PL457. During 2014 the reserve estimates have been updated as a result of the inclusion of volumes from PL457 and PL338 BS, as well as positive results from well 16/1-16 in PL457.

The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) includes production of the reserves also from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase. The Ivar Aasen and West Cable reservoirs will be developed with a manned production platform located above the Ivar Aasen reservoir and with a planned subsea installation on Hanz tied to the Ivar Aasen platform. The West Cable discovery will be drained through one well drilled from the Ivar Aasen platform.

The development of Ivar Aasen is coordinated with the adjacent Edvard Grieg field, which will receive partially processed oil and gas from the Ivar Aasen field for further processing and export. The Edvard Grieg platform will also provide the Ivar Aasen platform with gas lift and electricity.

On June 30, 2014, a unitization agreement for Ivar Aasen and West Cable was entered into with the licensees in PL457 and PL338BS. The unitization agreement was approved by the MPE on October 29, 2014. A commercial solution for Hanz is likely to be entered into in connection with a final decision on when to initiate Hanz production.

Det norske holds a 34.7862 interest in the Unit. The other licensees are Statoil Petroleum AS (41.4730), Bayerngas Norge AS (12.3173%), Wintershall Norge AS (6.4615%), VNG Norge AS 2.0230%), Lundin Norway AS 1.3850%) and OMV (Norge) AS (0.5540%).

3.2.2 Gina Krog (PL029B)

Gina Krog, formerly known as Dagny, is an oil field discovered in 1974. The reservoir contains oil and gas in Middle Jurassic sandstones in the Hugin Formation. The reservoir lies at a depth of about 3,700 meters. The field is located in the middle of the North Sea 250 kilometers west of Stavanger and 30 kilometers northwest of the Sleipner A installation, with a water depth of 110 to 120 meters. The development solution for Gina Krog is a new steel platform and a storage vessel for oil with a capacity of 850,000 barrels. Drilling is planned using a jack-up rig. Oil will be transported by tankers via offshore loading (FSU). The rich gas will be transported to Sleipner for processing and onto Gassled for export. Condensate and NGL will be exported to Kårstø, in Norway. The PDO for Gina Krog was approved in May 2013.

First oil is scheduled for first quarter 2017 and the field is expected to be in production until 2037.

The field is unitized and Det norske holds an interest of 3.3% unit. The operator Statoil Petroleum AS holds a 58.7% interest, Total E&P Norge 38% and PGNiG the remaining 8%.

Total E&P Norge AS entered September 29th 2014 into an agreement with PGNiG Upstream International AS regarding assignment of 8 % participating interest in Gina Krog Unit to PGNIG. As of December 30th the assignment was completed.

3.2.3 Viper-Kobra (PL203)

Viper-Kobra is located within the Alvheim field approximately three kilometers south of the Kneler structure at a water depth of 120 to 130 meters. The discovery comprises the two discoveries Viper and Kobra which are believed to be in pressure communication. Viper-Kobra will be developed by two wells, one targeting Viper and one targeting Kobra. A new subsea 4 –slot manifold will be installed and tied back to the Volund field. The concept selection was passed by the partnership in April 2014 and the development was approved by the Board of Directors of Marathon Norge in May 2014. The license partners approved the development plan in December 2014. First oil is expected in late 2016.

Det norske, as operator, holds a 65% interest. ConocoPhillips Skandinavia AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.2.4 Bøyla (PL340)

The Bøyla field is located south of Volund approximately 28 kilometers from Alvheim at a water depth of 120 meters. The Bøyla reservoir interval is within the Palaeocene Hermod Formation sandstone, a deep marine, channelized submarine fan system, at a depth of approximately 2,050 meters. The field was discovered in 2009 and the PDO was approved in 2012. The field is developed with two horizontal production wells (targeting each of the eastern and western structural closures) and one water injection well, placed at the eastern edge of the western structural closure and between the two producers. Pilot wells were drilled in order to optimize the horizontal section of the western structure producer. The field will produce via a four-slot subsea production manifold and is tied-back to the Alvheim FPSO via the existing Kneler A production manifold.

Bøyla production start is planned in January 2015. Cessation of production from the Bøyla field is expected in 2030 together with abandonment activities relating to the other Alvheim Area fields.

Det norske, as operator, holds a 65% interest. Core Energy AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.2.5 Enoch (PL048 D)

Enoch is an oil field located in the middle part of the North Sea which straddles the border between the NCS and the UKCS at a water depth of 112 meters. The reservoir contains oil in Palaeocene sandstones at a depth of approximately 2,100 meters and the reservoir quality is variable. Production started in 2007. The field is developed with one subsea well tied back to the British Brae field. The oil is processed on Brae A and exported through the Forties pipeline system to the UK. Due to technical problems, the field has not produced since the first quarter of 2012. Det norske believes Enoch will recommence production in 2015.

The Enoch field is unitized, the Norwegian section constituting 20% and the UK section constituting 80%. Of the 20% located on the NCS, Det norske holds a 10% interest corresponding to 2% of the unitized field. Other licensees in Enoch are Talisman Sinopec North Sea Limited as the operator (24% interest in the unitized field), Dana Petroleum (BVUK) Limited (20.8%), Dyas UK Limited (14%), Roc Oil (GB) Limited (12%), Statoil Petroleum AS (11.78%), Endeavour Energy UK Limited (8%), Noreco Norway AS (4.36%), Faroe Petroleum Norge AS (1.86%) and Talisman Sinopec LNS Limited (1.2% interest).

4 Contingent Resources

Det norske oljeselskap ASA has interests in 28 discoveries/projects containing oil and/or gas volumes classified as contingent resources.

Six of these discoveries/projects are in the planning phase; “Development Pending”. These are Frøy, Storklakken, Frigg Gamma/Delta, Fulla, Krafla and Johan Sverdrup. A more detailed description of these assets are given below.

Twelve discoveries/projects are classified as “Development Unclarified or on Hold”; Litjklakken, Ragnarrock Basement, Freke, P-Graben, Garantiana, Gotha, Askja, Trell, Steinbitt, Gekko, Caterpillar and Grevling.

In addition, Det norske holds interests in 10 discoveries classified as “Development not Viable”.

Development Pending:

- PL 265 (Well 16/2-8) Johan Sverdrup – operated by Statoil, Det norske 20% share
- PL 364 (Well 25/5-1) Frøy - operated by Det norske, Det norske 50% share
- PL 035B and PL 362 (Well 30/11-7) Fulla – operated by Lotos, Det norske 15% share
- PL 442 (Well 25/2-17) Frigg Gamma/Delta - operated by Centrica, 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 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 554 (Well 34/6-2S) Garantiana – operated by Total, Det norske 20% share
- PL 492 (Well 7120/1-3) Gohta – operated by Lundin, Det norske 40% share
- PL 272 (Well 30/11-9S) Askja – operated by Statoil, Det norske 25% share
- PL 102F (Well 25/5-9) Trell – Operated by Total, Det norske 10% share
- PL035/272 (Well 30/11-5) Steinbitt – Operated by Statoil, Det norske 25% share
- PL203 (Well 24/5-3) Gekko – Operated by Det norske, Det norske share 65% share
- PL340 BS (Well 24/9-10S) Caterpillar – Operated by Det norske, Det norske 65%
- PL 038D (Well 15/12-23) Grevling – operated by Talisman, Det norske 30% share

4.1 Development Pending

As the unitization process on Johan Sverdrup at the end of 2014 was in the final phase, Det norske has chosen not to give any information regarding recoverable volumes from the PL 265/PL502 Johan Sverdrup discovery in this statement of reserves.

Excluding the 20% share in PL265 and 22.22% in PL502 of Johan Sverdrup the “Development Pending” net resource estimate ranges from 72 to 113 million barrels of recoverable oil equivalents.

4.1.1 Johan Sverdrup (PL265, PL501, PL502)

The discovery well 16/2-6 on the giant Johan Sverdrup discovery was drilled in 2010. The well proved oil in Jurassic and pre-Jurassic sandstones on the Utsira High. Since that time, more than 30 appraisal wells including sidetracks have been drilled. Seven drill stem tests have confirmed excellent reservoir properties with massive continuous sands with permeability of tens of Darcy.

The reservoir consist of late Jurassic coarse grained sandstones in the Draupne Formation and early Jurassic to late Triassic finegrained sandstones in the Vestland Group. The culmination of the discovery is estimated at approximately 1800 mMSL TVD, with a varying FWL from approximately 1922 to 1934 mMSL TVD. The reservoir fluid is highly undersaturated oil with low GOR of 40 Sm3/Sm3 and a viscosity of approximately 2 cP.

A pre Unit agreement between PL501 and PL265 (50% - 50%) which was signed in March 2012 regulates the Johan Sverdrup development work until a unit agreement is established prior to a Phase 1 PDO submittal. Statoil was assigned working operator for the pre unit work.

Current plans call for a phased development of the field with submittal of a Phase 1 PDO February 13th 2015 and production start Q4 2019. The Phase 1 development plan assumes a field center with four platforms; processing platform, drilling platform, riser and export platform and living quarters. The platforms will be installed on steel jackets linked by bridges. Phase 1 includes also 18 oil production and water injection wells and 3 subsea water injection frames. Future development phases shall maximize value creation and ensure optimal utilization of all areas that constitute the field. Concept selection for future phases is scheduled for Q4 2015. The PDO for the future phases is planned for Q4 2017 and production start is planned in 2022. Fully developed, approximately 75 oil production and water injection wells will be drilled on Johan Sverdrup and the oil plateau production is expected to be approximately 600,000 barrels of oil pr. day.

The export solution for oil and gas will be transportation to shore via dedicated pipelines. The oil will be transported to the Mongstad terminal and the gas will be transported via the Statpipe system to Kårstø for processing and onward transportation.

As the unit negotiations at the end of 2014 were in a final phase, Det norske will not report any volume range for Johan Sverdrup before a unit agreement has been signed and the PDO for Phase 1 has been submitted. Det norske will at the same time up-grade the Johan Sverdrup recoverable volumes from contingent resources to Reserves (Justified for Development).

4.1.2 Frøy (PL364)

Frøy was in production from 1995 to 2001 with Elf as the operator. Elf shut-down the field in 2001 due to several reasons, including technical challenges, recovery rates falling below expectations and low oil prices. The licensees have worked on getting the field redeveloped. In 2008, a PDO was submitted, but was postponed due to the financial crisis. Through 2010 the Frøy group matured alternative concepts to establish a more robust concept featuring a leased field center (FPSO/JUDPSO) combined with a WHP. The goal was to deliver an updated PDO. During spring 2011 the work on preparing an updated Frøy PDO was put aside. The PL364 group is currently considering its options with respect to future field redevelopment.

Gross resource estimate for the Frøy discovery ranges from 55 mmboe to 86 mmboe.

Det norske and Premier Oil Norge AS each hold a 50% interest in Frøy. If redeveloped, expected production from this field could provide Det norske with an additional 20,000 boepd in production on plateau.

4.1.3 Frigg Gamma Delta (PL442)

The discovery of oil in East Frigg Delta (PL442) through well 25/2-17 is being evaluated by the operator Statoil Petroleum AS and includes re-evaluation of the Epsilon prospect and the Oligocene Dalton discovery. PL460 contains a discovery and prospects that could be relevant for a Frøy redevelopment. Currently, the PL442 group is weighing its development options.

Gross resource estimate for the Frigg Gamma discovery ranges from 73 mmboe to 109 mmboe.

4.1.4 Krafla (PL035 and PL272)

The Krafla discoveries (wells 30/11-8S and 30/11-8A) are located in the northern part of the North Sea, between the Oseberg and Frigg fields. The water depth is 108 meters.

Krafla is divided into two structures, the Krafla Main drilled by well 30/11-8S and Krafla West drilled by well 30/11-8A, which were both discovered in 2011. Several contacts and varying fluids characterize Krafla. In Krafla Main, free oil was found in the Upper/Middle Tarbert Formation and free gas was found in the Ness Formation below. In Krafla West free oil was found in the lower Heather Formation and free gas was found in the Tarbert Formation below. For most zones, an oil-down-to or gas-down-to situation exists.

The Krafla project is in the concept selection phase, and the current schedule implies DG2 in 2016.

Gross resource estimate for the Krafla discovery ranges from 76 mmboe to 116 mmboe. In addition to the Krafla discovery the license also includes the 2014 Askja discovery. Limited development considerations has been made for this discovery. Preliminary resource estimates are from 6 to 17 mmboe.

Note also that an appraisal well has been drilled on Krafla in 2015 with very promising results which has increased the resource potential significantly for the license compared to the estimates given above.

Det norske's interest in license PL035 and PL272 is 25%. The other licensees are Statoil Petroleum AS, who acts as operator, with a 50% interest and Svenska Petroleum Exploration with a 25% interest in the license.

4.1.5 Storklakken (PL450)

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 development installation.

Gross resource estimate for the Storklakken discovery ranges from 7 mmboe to 12 mmboe.

Storklakken is operated by Det norske and Det norske holds 100% interest in the license.

4.1.6 Fulla (PL362)

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. Lotos is the operator and Det norske holds a 15 % interest.

Gross resource estimate for the Fulla discovery ranges from 28 mmboe to 53 mmboe.

For all the assets within the subclass "Development Pending", RNB2015 reporting files to NPD has been used for assessing the potential.

4.2 Development not clarified or on hold

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 uncertain. However, the estimated sum of the low estimates amounts to approximately 82 million boe. The sum of the high estimates amounts to approximately 208 million boe. RNB2015 reporting to NPD October 2014 is the basis for the volume estimates for all the discoveries.

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 minor Enoch Field) have been certified by an independent third party consultancy (AGR Petroleum Services AS). These are the producing fields Alvheim (including Boa), Vilje, Volund, Varg, Jotun, Atla, Jette and the field under development; Ivar Aasen, Hanz, Gina Krog, Viper/Kobra and Bøyla.

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, a long term exchange rate of 6.0 NOK/USD, and a fixed oil price of 85 USD/bbl (real 2014 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.

Karl Johnny Hersvik
CEO

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.