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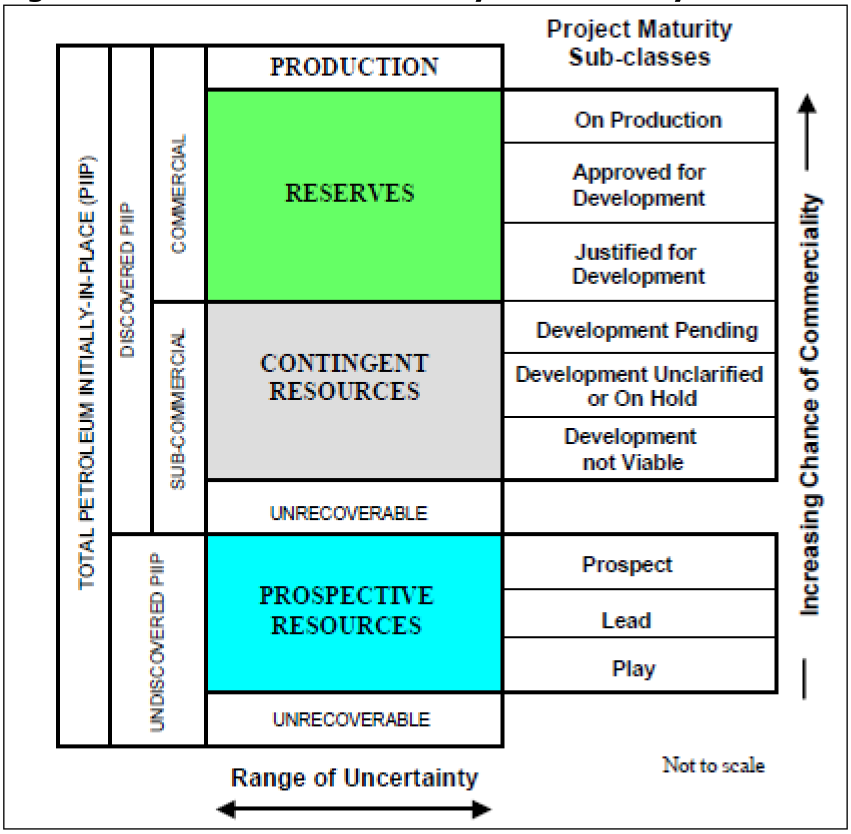
1 Classification of Reserves and Contingent Resources

The reserve and contingent resource volumes have been classified in accordance with the SPE classification system "Petroleum Resources Management System" and are consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources, see figure below.

Figure 1 – SPE's classification system used by Det norske oljeselskap



2 Reserves, Developed and Non-developed

Det norske oljeselskap ASA has interests in nine fields/projects containing reserves. Out of these nine 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 Glitne has reserves in both "On Production" and in "Proved for Development".

Sub-class "On Production":

- Varg – operated by Talisman, Det norske 5%
- Glitne – operated by Statoil, Det norske 10%
- Enoch – operated by Talisman, Det norske 2%
- Jotun – operated by ExxonMobil, Det norske 7%

Sub-class "Approved for Development":

- Atla – operated by Total, Det norske 10%
- Glitne infill 2012 – operated by Statoil, Det norske 10%

Sub-class “Justified for Development”

- Draupne project – operated by Det norske, Det norske 35%
- Jette – operated by Det norske, Det norske 88 %
- Dagny – operated by Statoil, Det norske 2% (Pre Unit Agreement cost share)

Total net proven reserves (P90/1P) as of 31.12.2011 to Det norske are estimated at 47.34 million barrels oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 67.89 million barrels oil equivalents. The split between liquid and gas and between the different sub categories are given in Table 1.

The changes in reserves during 2010 are presented in Table 2.

The main changes compared to reserve estimates as of 31.12.2010 is the introduction of the four fields Draupne, Atla, Jette and Dagny which all have been reclassified to “Reserves” during 2011. Note that the Draupne Project is defined by the Draupne Field (discovery well 16/1-9, PL 001B), The West Cable Field (discovery well 16/1-7, PL 001B, extending into PL 242) and the Hanz Field (discovery well 25/10-8, PL 028B). These three licenses have identical partnerships and a common development solution is defined.

Table 1 – Reserves by field

On Production	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids	Gas				Liquids	Gas			
As of 31.12.2011	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
Enoch Unit	1,80		1,80	2 %	0,04	2,70		2,70	2 %	0,05
PL 048B Glitne	0,00		0,00	10 %	0,00	2,10		2,10	10 %	0,21
PL 038 Varg	0,00		0,00	5 %	0,00	4,40		4,40	5 %	0,22
Jotun Unit	2,57	0,05	2,85	7 %	0,20	4,29	0,05	4,57	7 %	0,32
Total					**0,24**					**0,80**
Approved for Development	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids	Gas				Liquids	Gas			
As of 31.12.2011	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
PL 102C Atla	0,50	0,48	3,50	10 %	0,35	1,70	1,49	11,10	10 %	1,11
PL 048B Glitne infill 2012	2,10		2,10	10 %	0,21	4,60		4,60	10 %	0,46
Total					**0,56**					**1,57**
Justified for Development	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Liquids	Gas				Liquids	Gas			
As of 31.12.2011	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	(million barrels)	(bcm)	Total million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
Draupne	88,29	2,82	105,99	35 %	37,10	134,94	1,35	143,39	35 %	50,19
Jette	5,95	0,25	7,51	88 %	6,61	10,61	0,37	12,93	88 %	11,38
Dagny*	71,63	11,16	141,81	2 %	2,84	99,18	15,70	197,91	2 %	3,96
Total					**46,54**					**65,52**
Total Reserves					**47,34**					**67,89**

* Det norske share based on cost sharing agreement. Unit agreement to be concluded 2012.

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

Net attributed million barrels of oil equivalents.	**On production**		**Approved for Development**		**Justified for Development**	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance as of 31.12.2010	0,71	1,34	0,00	0,00	0,00	0,00
Production	-0,56	-0,56				
Acquisitions/disposals						
Extensions and discoveries			0,21	0,46		
New developments			0,35	1,11	46,54	65,52
Revisions of previous estimates	0,08	0,02				
Balance as of 31.12.11	0,24	0,80	0,56	1,57	46,54	65,52

The **Varg Field** (PL 038) is located south of Sleipner Øst. The field is operated by Talisman and developed with the production vessel "Petrojarl Varg" with integrated oil storage, and connected to a wellhead platform. Oil is exported using shuttle tankers. Two wells were drilled in 2011, but unfortunately these came in dry. Total production at Varg is approximately 19,000 bopd by year-end 2011.. Total ultimate recoverable reserves are estimated at 95 million barrels of oil, while total remaining proved and probable reserves (2P/P50) are 4.4 million barrels. The economic production cut-off is at the end of 2015.

The Varg Operator is planning two infill wells in 2012/ 2013 and also a possible later infill drilling campaign from 2014 and onwards. A gas export project is also under evaluation and a possible gas export of associated and re-injected gas could start in 2014. These projects may extend the field life significantly and add reserves. As no firm decisions have been made on these projects, possible resources have been classified as "Contingent Resources"..
Note that there are reported no proven (P90/1P) reserves. This is because the operator's low case RNB 2012 profiles indicated no economic production beyond 31.12.2011. The Varg Field is, however, so far producing at significantly higher rates than the prognosis for 2012, currently at approximately 19,000 bopd. As of end of January 2012 Varg has therefore proven (P90/1P) reserves beyond 31.12.2011.

The **Glitne Field** (PL 048B) is located 40 kilometers north of the Sleipner area. The field is operated by Statoil and produced by sub-sea wells tied to the production vessel "Petrojarl 1", and oil is exported using shuttle tankers. Total ultimate recoverable reserves are determined by the operator, based on a production cut-off in September 2014, and estimated at 61 million barrels of oil. Remaining proved and probable reserves (2P/P50) are estimated at 6.7 million barrels of oil. 2.1 million barrels are classified as "On Production" and are related to existing wells. The remaining 4.6 million barrels are classified as Approved for Development, and are related to the planned infill well in 2012 (both added production from the well itself and prolonged production from existing wells). The main uncertainties in future production are related to the production from the planned infill well, water cut development for individual wells and the production efficiency on Petrojarl 1.

An amendment to the Glitne production contract with Teekay Petrojarl signed late 2011 secures production to September 2014, if economically viable for the partnership The amended contract implies, however that Glitne will be shut down no later than this time. The planned infill well in 2012 will most likely extend the field life to September 2014. The cut-off date assuming existing wells only is, however estimated at 31.12.2013.

Note that also for Glitne no proven (P90/1P) reserves are reported as of 31.12.2011 for the reserve category "On Production", based on the operator's RNB 2012 profiles. But also Glitne produces p.t. at higher rates than the prognosis (3000 bbl/day in January). Proven (P90/1P) reserves have therefore been demonstrated through the January 2012 production history.

The **Enoch Field** (PL 048D) straddles the Norwegian/UK border and is located in the UK block 16/13a and in the Norwegian block 15/5 southwest of the Glitne Field. The field is operated by Talisman and developed by a single, horizontal sub-sea well and tied back to the UK Brae A platform where the oil is processed and exported via the Forties pipeline network. The gas is sold to the Brae Field. Production started in May 2007 and field shut down is expected in 2017. Depending on reservoir performance, one additional producer may be drilled using the extra well slot which is available. The field has been unitized with the license owners in British sector, and Det norske's overall share is 2% (10% of the Norwegian license PL 048D). Total initial proved plus probable reserves (Enoch Unit) are estimated by the operator at 12 million barrels of oil equivalents of which 2.7 million barrels remain (2P/P50). Volumes in Table 1 include only the Norwegian part of the field and are included under "Developed assets".

The **Jotun Field** (PL 027B, PL 103B) is developed with an integrated well head platform (Jotun B) with 24 well slots and an FPSO (Jotun A). Oil is shuttled to the Slagen refinery and gas is exported into Statpipe. Operator is ExxonMobil. 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 2016. Remaining reserves are determined by the operator based on decline analysis. The main uncertainty in future production is the water cut development in individual wells. Total ultimate recoverable reserves are estimated at 152 million barrels of oil equivalents, while remaining proved and probable reserves (P50/2P) are 4.6 million barrels. Det norske is now developing the small Jette oil discovery as a subsea tie back to Jotun. Production start is expected early 2013. Opex sharing with Jotun from 2016 may extend the Jotun production lifetime and increase remaining reserves.

The 7% Det norske share in Jotun gives net proven reserves (P90/1P) of 0.2 million oil equivalents and net proven plus probable (P50/2P) of 0.32 million oil equivalents.

Det norske's share of production from the Varg, Glitne, Enoch, and Jotun fields during 2011 amounts to 0.56 million barrels of oil equivalents.

The **Atla Field** (PL 102C) is a small gas discovery located in block 25/5 approximately 24 km north east of Heimdal and approximately nine km north of the subsea facilities on Skirne and Bygve. The discovery well 25/5-7 was drilled in October 2010 and the well proved rich gas/condensate in the middle Jurassic Brent Group. A PDO was issued to the MPE in July 2011 and was approved by the Ministry November 4th 2011. Operator is Total.

The field is under development and the selected development solution is a simple subsea tie-back of well 25/5-7 to the Skirne/Bygve subsea facilities. The well stream will be transported to the Heimdal facilities through the existing Skirne/Bygve flow lines. Note that the Atla Field is an analogue to the Skirne and Byggve fields also operated by Total and a high recovery factor is anticipated. Planned start up is Q4 2012.

Main uncertainty is the possibility of an oil rim below the proven gas column in the well (GasDownTo situation). The process at Heimdal can handle a potential element of oil in the gas/condensate wellstream, but overall production profile and recoverable volumes may be affected negatively.

Total proven (P90/1P) reserves are estimated at 3.50 million barrel oil equivalents and total proven plus probable reserves (P50/2P) are estimated at 11.1 million barrel oil equivalents corresponding to 0.35 and 1.11 million barrels oil equivalents net to **Det norske** respectively with a 10% share field.

The **Jette Field** is a small oil field with an minor gas cap and covers parts of the licences PL 027D, PL 169C and PL 504 in the blocks 25/7 and 25/8. The field is located approximately six km south of the Jotun Field. The field was discovered by well 25/8-17 and the sidetrack well 25/8-17A in October/November 2009. The wells proved oil and gas in the Paleocene Heimdal Formation.

A PDO was submitted to the MPE September 2011. A final approval from the Ministry is anticipated within February 2012. Det norske is operator.

The selected development solution is a two wells subsea tie-back to the Jotun B installation. The wells will have horizontal sections of approximately 1500 to 1900 meters through the reservoir. No artificial pressure support will be necessary. Gas lift will be provided from Jotun B. The installations will be prepared for drilling of a possible third well if drilling of the initial wells supports a commercially attractive oil potential to the south east of the main accumulation. The wellstream will be transported from Jotun B to Jotun A for processing, storage and offloading.

A recovery factor of 30% is anticipated for the reservoir segments that will be drained by the two initial production wells, which gives proven plus probable (P50/2P) gross reserves of 10.61 million barrels oil and 2.33 million barrels oil equivalents gas. Proven (P90/1P) reserves are estimated at 5.95 million barrels of oil and 1.57 million oil equivalents of gas respectively. The applied recovery factor of 30% is comparable to that of Jotun East (Tau), which has a 12 years production history with a similar geological and production well setting.

The Jette Unit has two partners; **Det norske** (Operator, 88%) and Petoro (12%).

Net proven reserves (P90/1P) to Det norske are therefore 6.61 million barrels oil equivalents. Net proven plus probable reserves (P50/2P) are 11.38 million barrels oil equivalents.

The Draupne Project, consisting of the three fields Draupne (16/1-9, PL 001B), West Cable (16/1-7, PL 001B, extending into PL242) and Hanz (25/10-8, PL 028B) is operated by Det norske. For Draupne and West Cable the reservoir units are the Hugin/Sleipner Formations of middle Jurassic age and the Triassic Skagerrak Formation. The Hugin Formation consists of tidal dominated shallow marine deposits while the Sleipner and Skagerrak formations are fluvial channel sandstones. West Cable is slightly undersaturated while a gas cap is present in Draupne and Hanz. The hydrocarbon bearing reservoir section in Hanz is the Upper Jurassic Draupne formation which has excellent reservoir conditions with multi Darcy sandstones. The Draupne discovery is by far the largest with in place hydrocarbons in the range of 300 million oil equivalents. The West Cable and Hanz have in place volumes of 24.0 and 31.4 million barrels oil equivalents respectively.

The three discoveries will probably be developed as a joint development with the Luno Field. The Luno Field, operated by Lundin Petroleum, is located approximately 8 km to the south. The Draupne development will consist of a Hanz subsea tie-back to a permanently manned minimum processing wellhead platform on Draupne, which is tied back to the Luno platform. The Draupne platform will utilize various services provided from Luno including supply of power and gas lift gas, and final processing of Draupne gas and oil.

The Draupne Field is planned developed with six producers and six water injectors and the West Cable with one producer only. All these producers will have a horizontal section through the reservoir and both the producers and injectors will be drilled from the WHP located at Draupne. The Hanz Field, which is located approximately 12 km to the north of Draupne, is planned developed with one vertical producer and one vertical injector. These wells will be completed as subsea wells tied back to the Draupne platform.

A joint development agreement with the Luno group is under negotiation. Further planning of major milestones are DG 2 in Q2 2012 and DG3 (PDO issue) Q4 2012. First oil is scheduled in Q4 2016.

Note that a small part of the reserves at Draupne may be located in neighbour license PL457, where Det norske has no equity interest.

Note also that the Det norske on behalf of the Draupne group has entered into a rig contract with Maersk Drilling for drilling of development wells on the Draupne project.

The Dagny Field is an oil and gas field located 30 km north-west of the Sleipner A installation in about 120 meter water depth. The field was discovered in 1974 and oil and gas is contained in the Upper Jurassic Hugin formation at a depth of approximately 3700 mTVD. Statoil is operator for Dagny.

The recommended field development plan comprises a new steel jacket platform. Oil is exported via offshore loading (FSU) and the rich gas is exported to Sleipner for processing and further export of sales gas through existing infrastructure.

The Dagny Field passed DG2 (BOV) late 2011 and all volumes reported herein are based on the Operator’s DG2 estimate.

Production start-up is assumed to be Q4 2016.

The Dagny field covers several licenses, as seen in Table 3.

The Dagny field covers several licenses, see Table 3.

Table 3 – Dagny Field licenses

License	Statoil	Exxon	Total	Det norske
PL 048	78,2 %		21,8 %	
PL 029	100,0 %			
PL 029B	50,0 %	30,0 %		20,0 %
PL 303	100,0 %			

A cost sharing agreement was established in 2010. This was based on a very preliminary volume split based on proven reservoir segments. Det norske has a 2% cost obligation according to this agreement.

Unitization negotiations will start February 2012 and the aim is to have a Unit Agreement signed prior to the PDO scheduled for Q4 2012. Det norske’s reserves reported herein are based on the share given by the cost sharing agreement. Note that this most likely is a minimum share for Det norske, since a majority of the undrilled segments are located in PL029B, where Det norske holds an equity interest.

A 2% share in Dagny gives net proven (P90/1P) reserves of 2.84 million barrels oil equivalents to Det norske and net proven plus probable (P50/2P) reserves of 3.96 million barrels oil equivalents to Det norske.

3 Contingent Resources

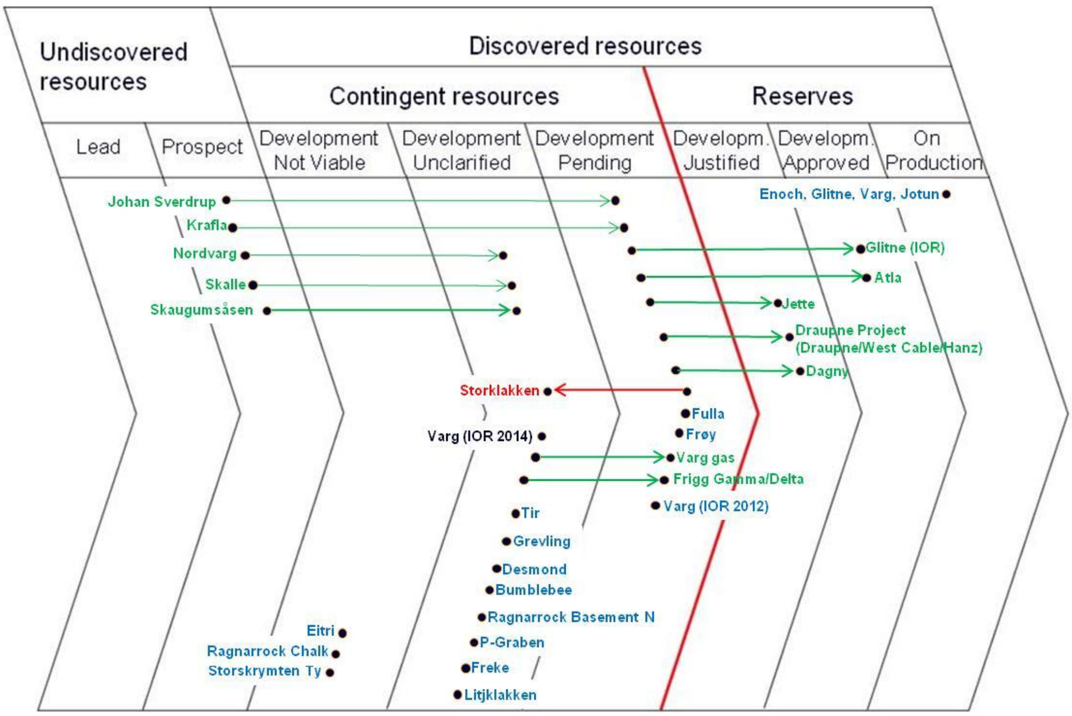
Det norske oljeselskap ASA has interests in 23 discoveries/projects classified as contingent resources, and a complete list is provided below. Seven of these discoveries/projects are in the planning phase ("Development Pending"); Varg Infill 2014, Varg gas blowdown, Frøy, Øst Frigg Gamma/Delta, Fulla, Johan Sverdrup and Krafla. The main changes in this category are the introduction of the new giant discovery Johan Sverdrup and the major Krafla discovery.

13 discoveries/projects are classified as "Development Unclarified or on Hold"; Varg Infill 2014, Grevling, Tir, Storklakken, Desmond, Bumblebee, Ragnarrock (Basement), Freke, P-Graben, Litjklakken, Norvarg, Skalle and Skaugumsåsen. The three latter are discoveries made during 2011.

Three discoveries are classified as non-commercial ("Development not Viable"); Storskrymten, Eitri, and Ragnarrock Chalk.

Figure 2 illustrates resource movements for fields and discoveries in 2011.

Figure 2 – Resource movements 2011



The main changes are reclassification of the Draupne, Jette and Dagny projects from Contingent Resources ("Development Pending") to Reserves ("Justified for Development") and the Atla project from Contingent Resources to Reserves ("Approved for Development").

Det norske participated in five discoveries in 2011; the PL 265 Johan Sverdrup discovery, the PL 272/035 Krafla discovery, the PL 535 Nordvarg discovery, the PL 438 Skalle discovery and the PL 482 Skaugumsåsen discovery. Two of these discoveries, Johan Sverdrup and Krafla can already be classified as commercial discoveries and are therefore placed in the sub category "Development Pending". The other three need further evaluations to prove commerciality and are therefore placed in the sub category "Development Unclarified or on Hold".

The Varg gas blow down project and the Øst Frigg Gamma/Delta discovery have moved into the planning phase ("Development Pending or on Hold") following decisions for concretization (DG1/BOK). The Varg Infill Well 2012 Campaign remains in the planning phase (i.e. most likely potential new production early 2013), while the Glitne Infill well 2012 Campaign has been moved from contingent resources to Reserves ("Approved for Development").

Note also that Storklakken has been downgraded from "Development Pending" to "Development Unclarified or on Hold".

"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
- PL038 Varg Infill 2012 – Operated by Talisman, Det norske 5 % share
- PL038 Varg gas blowdown – Operated by Talisman, Det norske 5 % share

Development Unclarified or on Hold":

- PL 460 (Well 25/1-11) Storklakken - operated by Det norske (100% share)
- 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 102C (Well 25/5-5) Tir – operated by Total, Det norske 10% share
- PL 332 (Well 2/2-2) Desmond - operated by Talisman, Det norske 40% share
- PL 332 (Well 2/2-5) Bumblebee - 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) Nordvarg – operated by Total, Det norske 20% share
- PL 438 (Well 7120/2-3S) Skalle – operated by Lundin, Det norske 10% share
- PL 482 (well 6508/1-2) Skaugumsåsen – operated by Det norske 65 % 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

The **Fulla discovery** made in 2009, has gross resources between 40 and 55 mboe and is planned to be developed as a tie-back to the Heimdal or Bruce (UK) fields. Det norske has a 15 % interest in this license. First production is expected in 2015, at the earliest.

The 2009 **Grevling discovery** with gross resources between 40 and 95 mboe may be developed as stand-alone or tie-in to Varg. Currently a long term production test is being evaluated, with potential production start 2013.

The East Frigg Gamma and Delta discoveries, with gross resources between 50 to 150 mboe, will most likely be developed as part of an area development.

The Frøy discovery operated by Det norske with gross resources between 50 and 85 mboe will most likely be developed as part of an area development.

The Storklakken discovery, with gross resources between 8.2 and 12. mboe will most likely be developed as a one well subsea tie-back, most likely to a future Frøy installation.

The giant discovery Johan Sverdrup (previously Aldous/Avaldsnes) made 2010-11 covers both PL 265 and PL 501. Gross resources for the field in PL265 are estimated from 900 mboe to 1500 mboe by the operator Statoil. Statoil will most likely be appointed as joint Operator for the Johan Sverdrup development project and is aiming for first oil in 2017 from a phased standalone development

Also the **Krafla discovery** made 2011 is a major discovery with gross resources ranging from 36 to 84 mboe. Several development solutions are currently being investigated by the Operator Statoil. These include a potential fast track development to Oseberg, with first oil in 2014/15.

The **Varg Field** Operator Talisman has identified two IOR projects which most likely will increase reserves and prolong the field life. These are infill wells which may be drilled in 2012/13 and a gas blow down project which could have first gas in 2013.

The PL 102C Tir discovery is very much a “look alike” to the Storklakken discovery with gross reserves in the same range and the same reservoir type. A most likely potential development will be a subsea tie-back to either an existing installation or to a future installation to the north.

The discoveries PL 332 Desmond and Bumblebee, PL 265 Ragnarrock Basement North and P-Graben, PL 029B Freke, PL460 Litjklakken (25/1-9 discovery), PL 535 Nordvarg (2011), PL 482 Skaugumsåsen and PL 438 Skalle have not yet been concluded with respect to economical viability.

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

In addition all volumes within the reserve category (except for the Dagny and Enoch Fields) have been certified by an independent third party expert (AGR Petroleum Services AS). These are the producing fields Glitne, Varg, Jotun and the still not developed fields Draupne (Draupne, West Cable and Hanz), Jette and Atla.

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 NOK/USD 6.00. Oil prices are based on 105 USD/bbl (real 2011 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
boe/d: 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.