Relinquishment Report PL362 and PL035B

Fulla kneeling beside her mistress, Frigg.

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1. Key license history

1.1 The current license owners are:

Lotos Exploration and Production Norway AS (50%), Operator
Svenska Petroleum Exploration AS (25%)
Det norske oljeselskap ASA (15%)
Dana Petroleum Norway AS (10%)

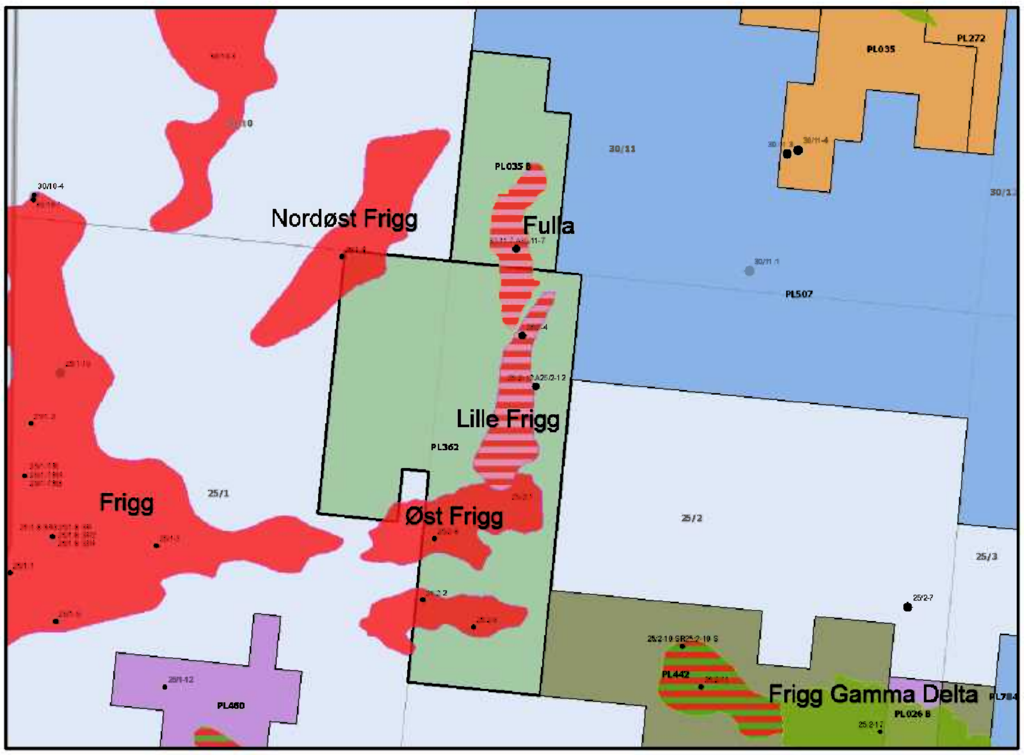

Figure 1: License map PL035B/PL362

1.2 Award and work program

PL362 was awarded January 6, 2006 with an initial period up to January 6, 2010. Work obligations were as follows:

4a) the license shall, within two years from the award date gather 3D seismic over the area of the production license.
Seismic data was gathered over the area including NH0609 and NVG10

4b) the license shall, within 2 years from the date of the award decide to drill an exploration well, it is possible to drill a prospect in PL035B if it is geo-technically justified.
Wells 30/11-7 and 30/11-7A were drilled in 2009

4c) the license shall, within 4 years from the award date decide whether to prepare a plan for continued development (BOV) of the Fulla field.
License has decided not to prepare a plan for continued development

1.3 Extension of deadlines

PL362 was awarded January 6, 2006 with an initial period up to January 6, 2011.

PL035 B was awarded November 26, 2008 with validity to November 14, 2015.
Both licenses have been allowed extension to January 6, 2016.

An extension was awarded November 16, 2009
PL362 deadline for BOV - January 6, 2011 and PUD January 6 2012

An additional extension was awarded November 26, 2010
PL362 deadline for BOV - July 6, 2011
PL035B deadline related to application for extension of extended period – January 6, 2012

An additional extension was awarded May 27, 2011
PL362 deadline for BOV - October 6, 2011

An additional extension was awarded October 21, 2011
PL362 deadline for BOV - November 6, 2012 and PUD September 6 2013
PL035B deadline related to application for extension of extended period – September 6, 2013

An additional extension was awarded November 15, 2012
PL362 deadline for BOV - March 15, 2013

An additional extension was awarded June 27, 2013
PL362 deadline for BOV - March 15, 2014 and extended initial period - March 15, 2015
PL035B extension of the extended period – January 6, 2016

An additional extension was awarded May 5, 2014
PL362 deadline for BOV - December 6, 2015 and extended initial period - January 6, 2016
PL035B extension of the extended period – January 6, 2016

In addition to the regular Management Committee and Advisory Committee meetings dedicated work meetings have been conducted to involve all partners in the evaluation of options.

The relinquishment is based on lack of commercially attractive options and high risk related to size of the field productivity and technical challenges related to high pressure and temperature.

2. Database

The database consists of a number of seismic datasets (Table 1, Figure 2) and wells (Table 2).

Table 1: Seismic database PL035B & PL362. Overview of main datasets used by the different operators (Statoil, Centrica & Lotos).

Seismic	Comment	New data
NH0609		
NH0609STR10	Time reprocessing by WesternGeco	
NH0609STZ10	Depth reprocessing by Statoil, processing group	X
NVG10	Fast track processing by PGS	X
NVG10STR11	Time processing by WesternGeco	X
NVG10STZ11	Depth processing by Statoil, processing group	X
NVG11	Time processing by PGS, merge with NVG10	X
NVG10STZ11_PSDM_KIR2	Main dataset used by Centrica	X
MC3D-NVG10STR11_FINAL	Optional dataset used by Centrica	X
MC3D-NVGSVGM2013	Main dataset of current operator Lotos	X

Table 2: Well database PL035B & PL362. Source Statoil & Centrica.

Well	Comment	New data
30/11-7 & 30/11-7A	Fulla discovery wells	X
25/2-4	Lille-Frigg. Gas discovery, Brent Gp.	
25/2-12	Lille-Frigg. Gas appraisal, Brent Gp.	
25/2-C-1 H	Lille-Frigg production	
25/2-C-1 AH	Lille-Frigg production	
25/2-C-2 H	Lille-Frigg production	
25/2-C-2 H	Lille-Frigg production	
30/10-5	Frigg Field. Oil appraisal in Frigg Fm., shows in Brent Gp.	
30/11-3	Dry well with shows in Brent Gp.	
30/11-4	Dry well with shows in Vestland Gp.	
30/9-16	Oseberg Sør. Oil discovery in Heather and Tarbert Fms.	
25/1-10	Frigg Field. Water swept in Frigg Fm., dry in Brent Gp.	

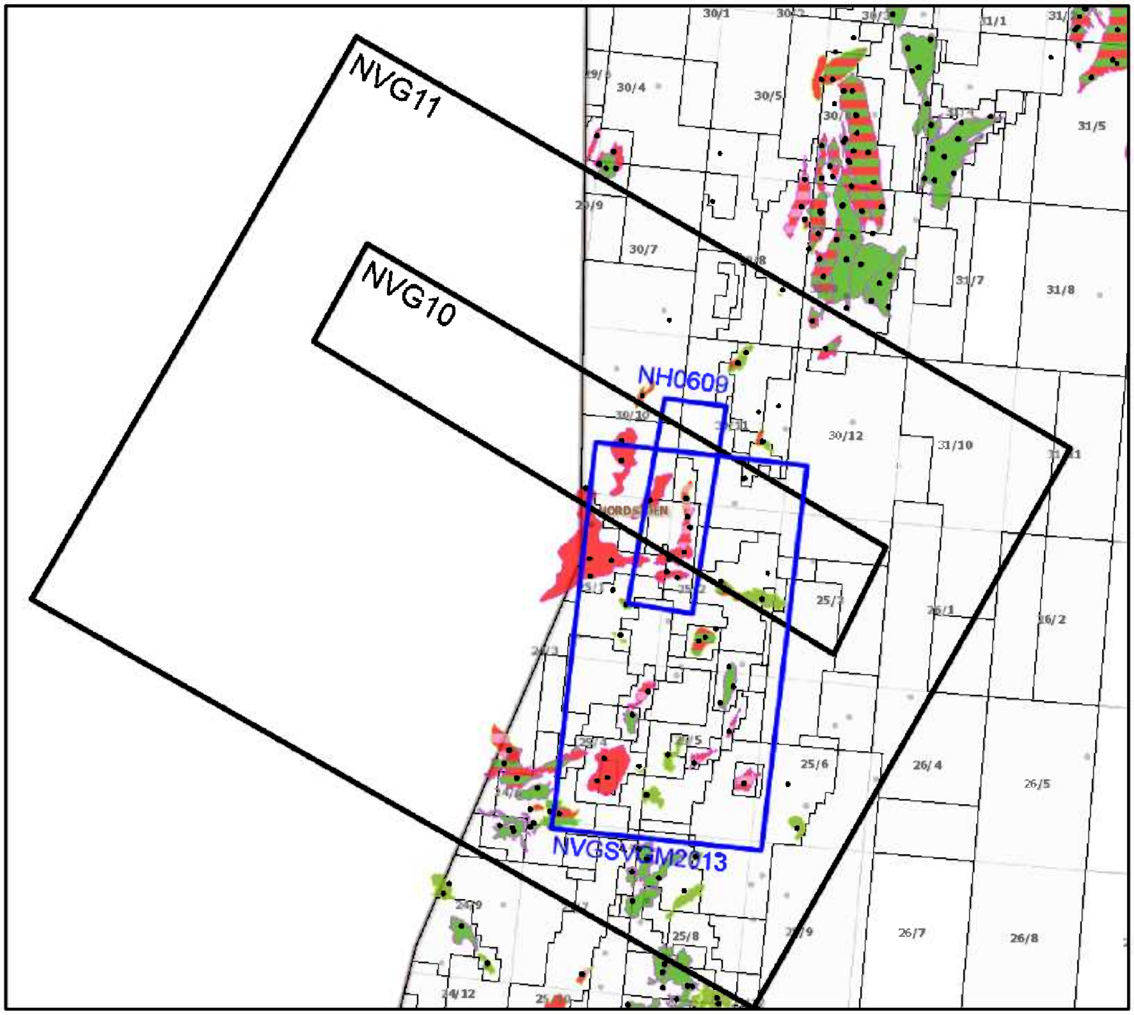

Figure 2: PL035B/PL362 seismic database, with approximate boundaries of seismic surveys.

3. Review of geological framework

Besides improved structural imaging from new seismic datasets (Table 1), the Fulla discovery wells constitute the main new data (Table 2). Several studies involving subsurface work have been performed during the license period (Table 3), and the conclusion is that no major changes in geological understanding occur as a result of the two Fulla wells.

Table 3: Fulla discovery evaluation and field development studies

Study	Company	Comment
Fulla Discovery Evaluation	Statoil	Including standard well analysis, e.g. biostratigraphy, core description/interpretation, routine core analysis, petrophysical analysis
Fulla BOK (DG1)	Statoil	Fulla Field development DG1.
Fulla BOV (DG2) – by partners	AGR	Fulla Field development DG2 study by partners, outsourced to AGR Petroleum Services.
Fulla BOV (DG2) – by operator	Centrica	Fulla Field development DG2 by Operator Centrica.
Assessment of gas column at Fulla	Lotos/AGR	Response to request by NPD related to risk of a)high water cut, and b)seal breach due to gas column
Miscellaneous		• SCAL • Core description and depositional interpretation, Ichron (for Centrica)

A summary of the geologic framework of the Fulla discovery is given below:

Fulla is located on the Eastern flank of the Central Viking Graben, on the northernmost part of the Utsira High between the Horda platform to the east and deeper part of Viking graben to the west (Figure 3). The Lille-Frigg structure constitutes a horst in this setting, and the Fulla structure (also a horst) is down-thrown from Lille-Frigg separated by a major fault. The main phase of extensional faulting occurred during the Upper Jurassic.

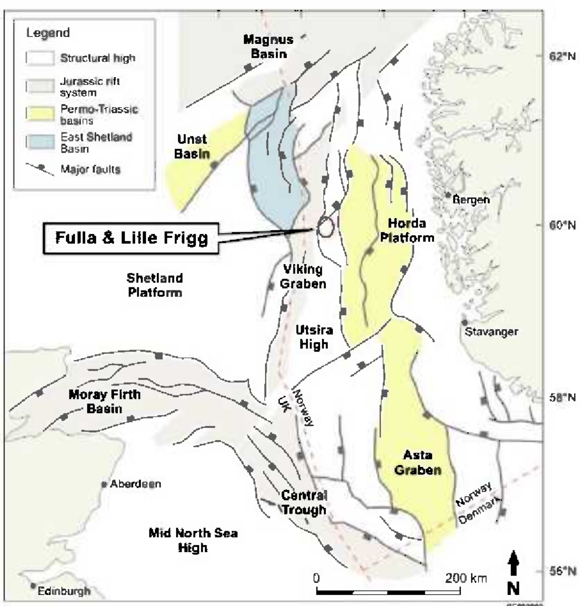

Figure 3: Regional structural setting. (Source Centrica DG2 SER, after Dominguez, R., 2007)

The reservoir target of the two Fulla wells was the Tarbert Formation in the Middle Jurassic Brent group, which also was the main reservoir of the Lille-Frigg field. Note that The Tarbert formation was not encountered in the main well (due to faulting and/or erosion); however hydrocarbons were found in the Ness Formation in this well.

The geology of the Brent group is in general well described. It was deposited by a major delta, which propagated northward through the Viking Graben during the Early Bajocian (Rannoch, Etive and lower Ness Formations), and retreated southwards and was transgressed during the Late Bajocian – Early Bathonian (upper Ness and Tarbert Formation). The Tarbert Formation comprises smaller progradational units of shoreface or delta front deposits capped by coal-bearing paralic or continental strata, in turn stacked as a series of generally back-stepping wedges deposited during the overall retreat of the Brent Delta system. The Brent Group is overlain by marine shales of the Heather Formation, forming the top seal. A summary of the depositional history of the Upper Brent Group at Fulla and Lille-Frigg area is shown in Figure 4.

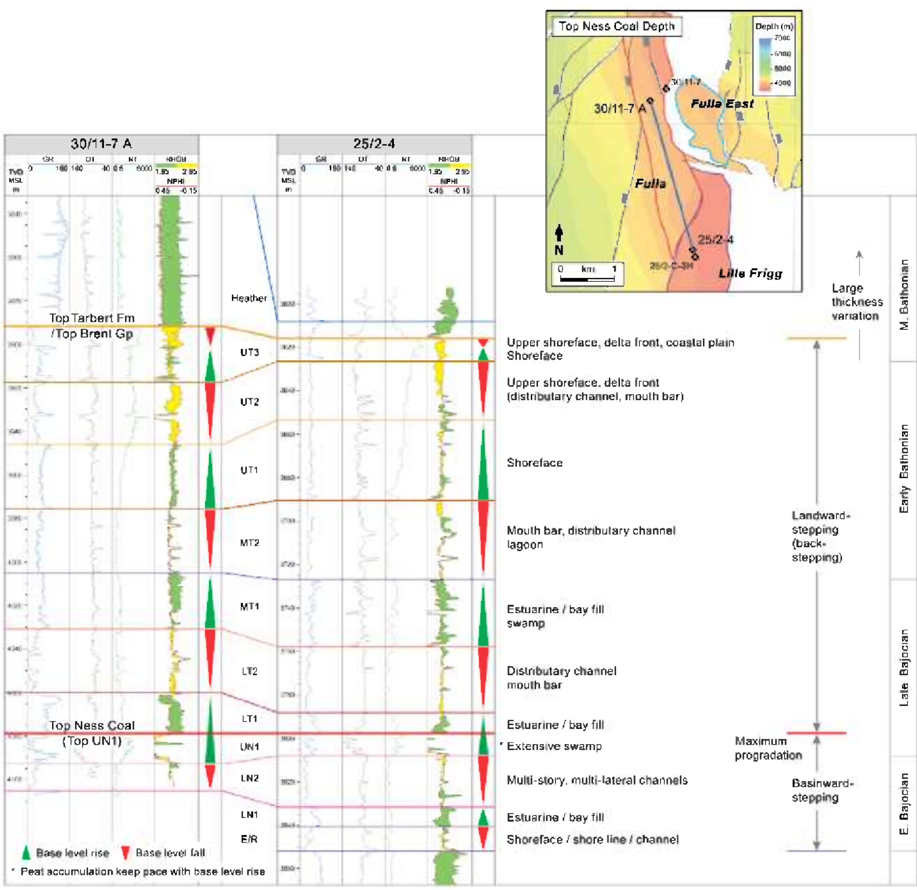

Figure 4: Reservoir zonation and depositional history of the Upper Brent Group in the Fulla and Lille-Frigg area (source Centrica BOV SER)

A summary of the sedimentological analysis of the Fulla wells is given below. Cores were taken in both 30/11-7 (Ness Formation) and 30/11-7A (Tarbert Formation).

In 30/11-7 (the main well) 15m of core was retrieved from the middle of the Ness formation, consisting of interbedded heterolithics overlain by sandstone and a single siltstone bed. The cored part represent channel bar and channel fill deposits. Sedimentary structures suggest both tidal and river influence, and a delta plain/coastal plain environment is interpreted. The sands range from fine to coarse grain sizes, and in such a paralic setting the reservoir quality will be variable. Interpretation of OBMI data suggests a roughly N-S oriented depositional axis, probably aligning perpendicular to the E-W paleo-coastline.

The sidetrack 30/11-7A is cored in the Tarbert Formation. The cored part consists of a lower succession of mainly very fine- to fine-grained sandstone showing a subtle upward coarsening trend, and an upper succession of mainly medium to coarse-grained sand with a coal interbed. The lower part is interpreted as delta front/distal mouth bar environment with abundant sediment supply from a fluvio-deltaic source, suggesting that the coastal plain of the Ness Formation was flooded prior to the deposition of Tarbert. Reservoir properties will be poor to intermediate. The upper part is interpreted as an estuarine environment, where the sandstones are interpreted as estuarine channel bar deposits, suggesting a regression from the lowermost to the uppermost succession in the core. The coal interbeds represents development of extensive coastal mires. The reservoir properties of the Upper Tarbert will be intermediate to very good.

4. Prospect update

Within PL035B and PL362 resources are found in shut-in fields, discoveries and prospects/leads.

1.4 Shut-in fields

The two licenses cover satellite fields of the Frigg development, including the Jurassic Lille Frigg field and partly the Nord-Øst Frigg and Øst Frigg field of Eocene age (shutdown in 1999).

Lille-Frigg was a gas/condensate field producing from the Tarbert Formation. Production started in 1975 and was shut-down in 1999 due to high water cut. As part of the partner Fulla BOV study, it was investigated if reopening of this field could add resources to a Fulla development. With favorable conditions additional resources of 1GSm3 is estimated, with main risk of high water cut.

1.5 Discoveries

1.5.1 Fulla

The Fulla discovery was made in 2009 by the well 30/11-7 and the sidetrack 30/11-7 A. The reservoir is over-pressured (719 bar absolute pressure at top reservoir), in line with maximum pressure expectations pre-drill.

30/11-7 proved gas-condensate in sandstones of the Ness Formation, with an estimated gas water contact at 3974 m MSL based on pressure results. The main prognosed reservoir of the Tarbert formation was not encountered in the well, due to intra Heather erosion and/or faulting.

The sidetrack 30/11-7 A is located only 300 m from the main well. It encountered a 177 m column of gas/condensate in the Tarbert Formation. PVT analysis suggests that the gas condensates in the main well and in the sidetrack are different, and that the two reservoirs are not in direct pressure communication. The Gas-Water contact is estimated at 3963 m MSL based on pressure measurements, however this is uncertain. Multiple contacts in a compartmentalized reservoir scenario may be possible over the Fulla structure.

The trap-style of Fulla is a fault bounded three-way closure, and the key seismic horizon defining the structure is the Top Ness Coal (Figure 5). This marker can be traced regionally, and can be correlated in several wells. Top Tarbert Fm is more difficult to pick, and significant uncertainties exist in the interpretation/modeling of this horizon. In addition, uncertainties also exist in the depth conversion due to overburden anomalies. As such there is uncertainty in the structural delineation of the discovery.

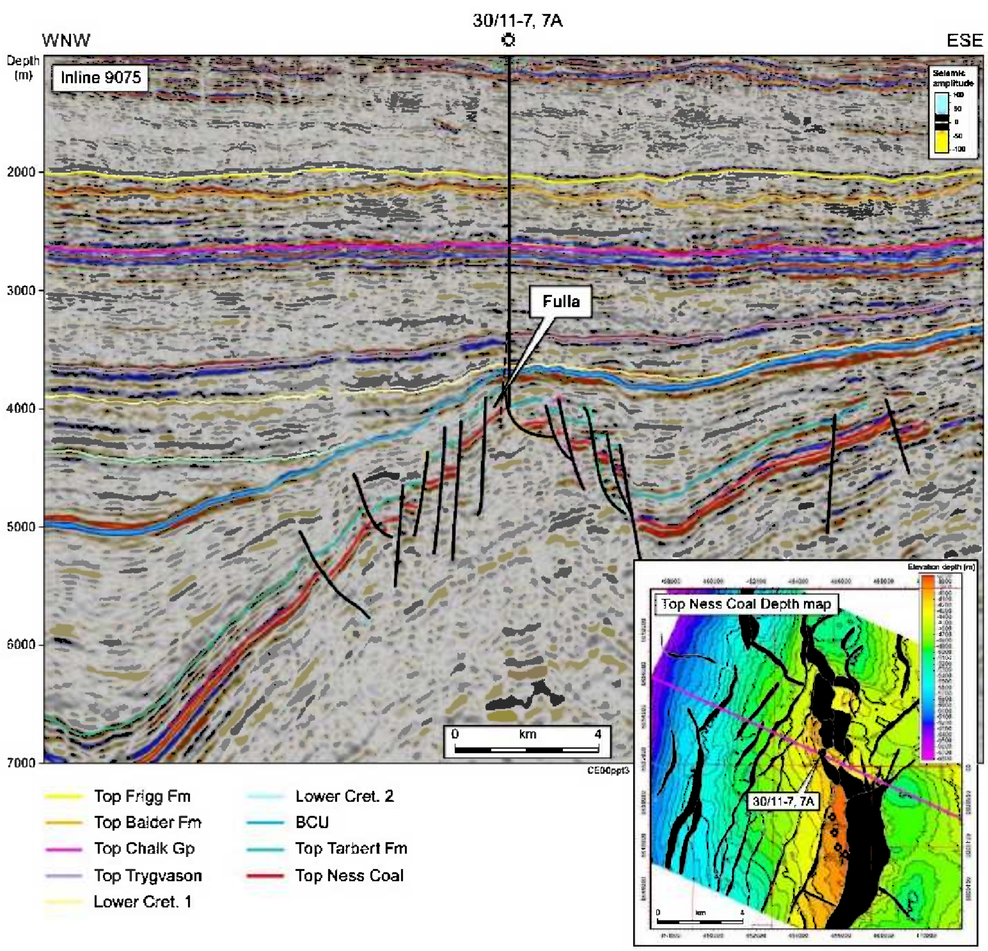

Figure 5: Example seismic line in the Fulla area. Source Centrica (DG2 SER).

The Fulla structure comprises two structural highs, informally named the Fulla North and Fulla South segments. The suggested development scenario is one gas producer in each segment with natural depletion as main drive mechanism. An overview of in place and resources is given in Table 4:

Table 4: Fulla discovery inplace and recoverable volumes. Source RNB2015.

	P90	Base	High
GIIP (GSm3)	9.9	11.6	13.6
Recoverable Gas (GSm3)	3.8	5.5	7.3
Recovery Factor (%)	38.0	47.0	54.0

A key risk with regards to potential future development, is the presence of hydrocarbons in the southern structure towards Lille-Frigg, and if this segment communicate with the northern structure. The southern part of Fulla is strictly speaking not considered to be proven, although there is consensus that the probability of failure is regarded as low. Another risk is the degree of compartmentalization in the Tarbert Formation, where the pressure measurements in 30/11-7A are non-conclusive with respect to the possible presence of multiple Gas-Water Contacts. Also, a key geological risk is the delineation of the structure to the North and East, and side-tracking may be required to hit the reservoir while drilling production wells.

With regards to upsides; a controversial issue is the possible presence of a fault within Tarbert in 30/11-7A. A potential missing section entails a thicker Tarbert Formation with a corresponding upside of in place volumes. Another upside; is the possibility of an intra-Tarbert barrier allowing for a significantly deeper fluid contact (GWC) in the main producing zone (upper Tarbert). Oil staining was observed in the discovery wells, and it is speculated that an oil leg may be found down flank. Finally the suggested development scenarios does not include volumes in the Ness Formation, as these volumes are currently not considered economic viable.

5. Technical evaluation

Fulla does not have sufficient resourses to make a standalone development commercially attractive. The DG1 base case concept was a subsea tie-back of Fulla to Heimdal. This development concept consisted of production from two wells, drilled from a common template with well fluids transported in a dedicated pipeline to Heimdal for processing. The gas and condensate would then be exported from Heimdal via the existing gas and condensate export pipelines. A positive DG1 decision was made in June 2011.

Further studies with the aim of reaching a DG2 were initiated based on the DG1 concept. The main technical challenge was related to flow assurance. The 52 km flowline to Heimdal flowing gas, condensate and water was vulnerable to hydrate formation. Two options were studied for hydrate mitigation; continuous MEG injection including regeneration at Heimdal and highly insulated pipe (PiP). Continuous MEG injection was screened out due to high cost. The two wells were based on proven NCS

HPHT well design, with a 9 7/8" production casing an 8 1/2" reservoir section with simple well trajectories at 35 deg tangent section through the reservoir.

Additional studies were initiated in late 2011 to determine if an improved project could be achieved by tying into the Bruce platform. BP, the Bruce Operator, concluded in June 2012 that the materiality of tying in Fulla was insufficient to warrant further study and this option was closed.

In the spring of 2012, renewed efforts were made to revive an area solution in the Frigg Gamma Delta area. While an area solution could offer potential for Fulla for to find a host, the effort proved to be too complex to establish with all the involved parties.

A simplified tieback to Heimdal with reduced brownfield scope was than worked to a DG2 level as a last attempt for a Heimdal tieback. This concept was finally screened out due to risk related to hydrate formation in the long flowline that could lead to low regularity and possibly long term plugging of the line.

In the spring of 2014 a renewed effort was made to find a host for Fulla production. It was attempted to establish an area forum to facilitate synergy effects for the partners in the area; without success.

The operators of Frigg Gamma Delta and Krafla were then approached to identify a concept where Fulla could be produced through a host platform. Screening studies was completed by Centrica and Statoil as host platform operators, along with some additional supporting studies. The results of the studies demonstrate the potential for a feasible Fulla development project both technically and commercially. With the weak market situation and the lack of maturity of the host candidates, including schedule uncertainty the license decided that development of Fulla was not robust enough to be continued.

6. Conclusions

6.1 Remaining petroleum potential

Several prospective reservoir levels are present in the area.

Eocene sandstones were the main reservoir in the Frigg, Øst-Frigg and Nord-Øst Frigg fields. However, no new leads are identified at this level.

The Early Jurassic **Statfjord Formation** consists of sandstones with reservoir properties, proved in the Lille-Frigg wells 25/2-4 and 25/2-12 (both water filled). Directly beneath the Fulla discovery a structural closure is also found at the Statfjord Formation level, but the Fulla wells were not drilled deep enough to encounter the Statfjord formation. In the work done by previous operator Statoil, a potential gas column of ~400 m is suggested, assuming sealing faults towards Lille-Frigg. Two key risks are (1) low permeability due to diagenesis (kaolinite), and (2) hydrocarbon migration downwards stratigraphically into the Statfjord Formation.

The Middle Jurassic **Brent Group** is a proven reservoir, with discoveries in both Fulla and Lille-Frigg. The group is sourced by the mature Upper Jurassic Draupne shales, and overlain by sealing shales of the Heather Formation. The Tarbert Formation is the main reservoir target, and the reservoir qualities are expected to be intermediate to very good. The trap style is mainly fault-controlled structures, and the key risk is the sealing properties of the bounding faults. The previous operator Statoil has identified a set of prospects/leads in the intermediate vicinity of the Fulla discovery, summarized in Figure 6.

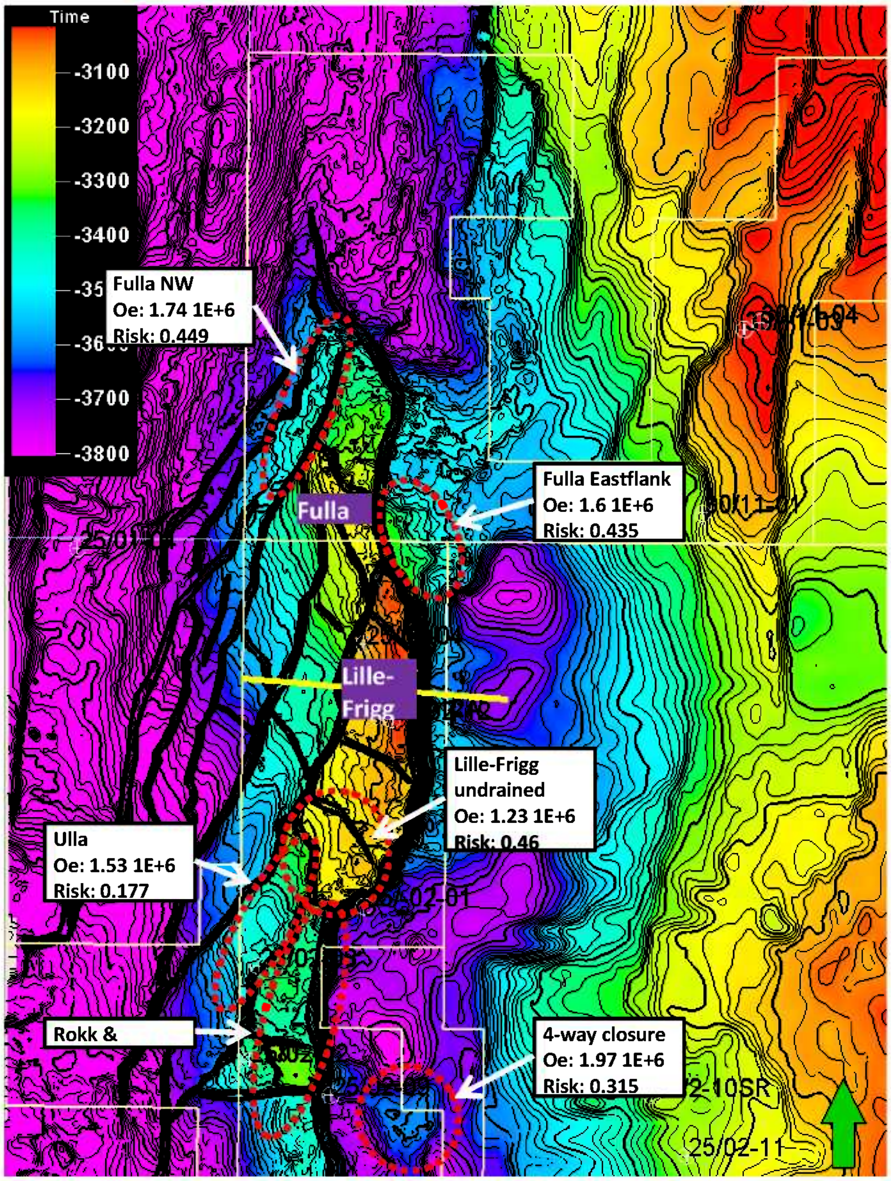

Figure 6: Overview of Brent Gp prospects/leads in PL035B/PL362, displayed on Top Ness Coal time interpretation. The volumes are estimated risked mean recoverable volumes, Tarbert + Ness Formation (Sm3 oe). Source Statoil 2010.

In addition, the current operator Lotos has performed a preliminary mapping based on the MC3D-NVGSVGM2013 seismic dataset, revealing a set of potential leads (Figure 7).

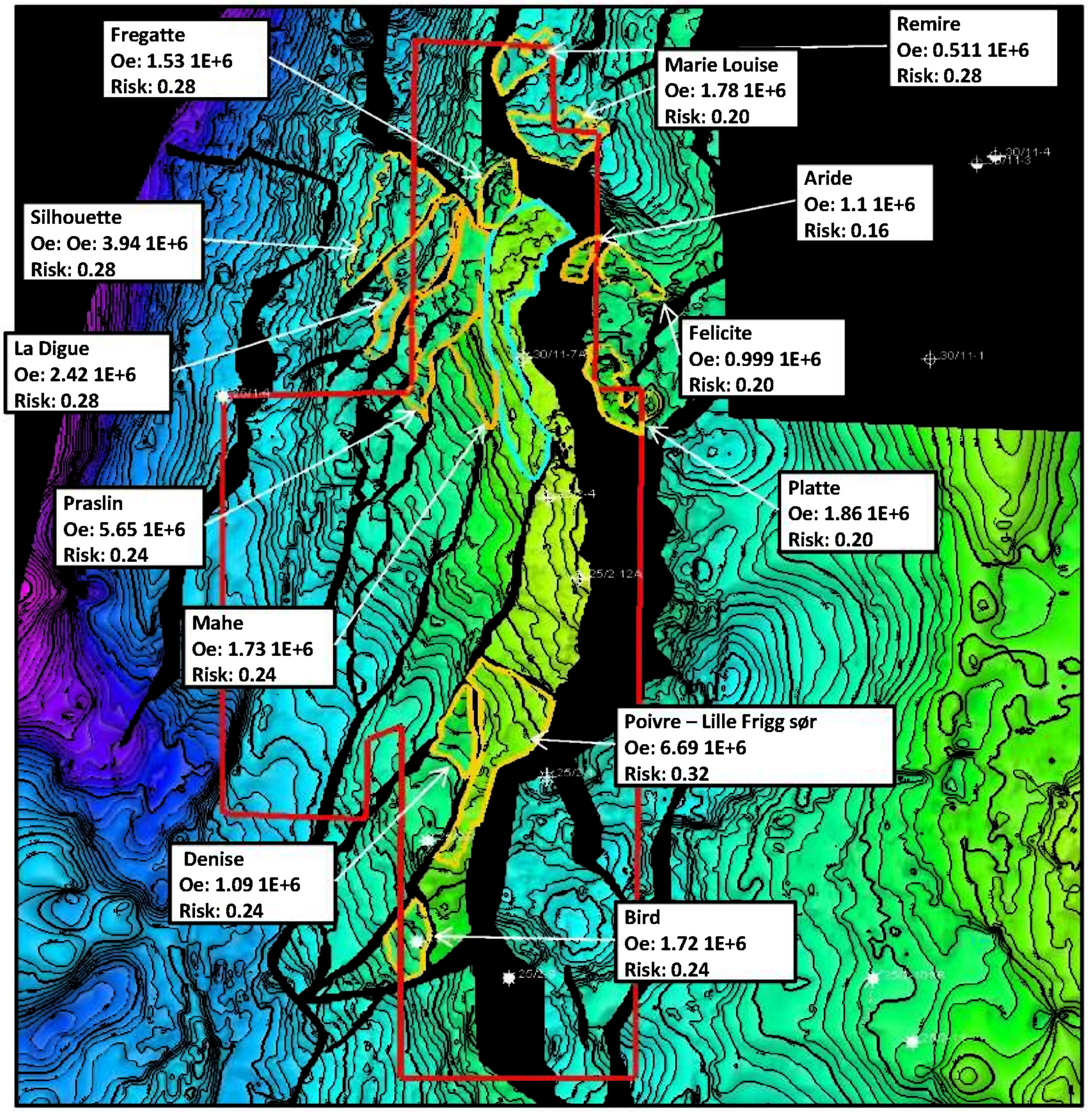

Figure 7: Overview of leads in PL035B/PL362, displayed on a preliminary Lotos interpretation of Top Ness Coal time map. Most leads assume a gas column of 230 m, and reservoir/fluid properties like the Fulla discovery. The volumes are estimated mean recoverable volumes (Sm3 oe)

6.2 Reason for relinquishment

It has not been possible to find a commercially attractive development concept. This is due to the low volume of hydrocarbons and the near HTHP conditions. Long distance to existing infrastructure increases the risk related to regularity and operability. Although there are possible hosts closer they are in early planning stages with no fixed date for availability to take Fulla production. The license has therefore concluded that there is too much risk and uncertainty in a possible development to continue.