Status Report

for

License PL618

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TABLE OF CONTENTS:

LIST OF FIGURES:

LIST OF TABLE :

1. History of the production license

PL618 was awarded in February 3, 2012 (APA2011 round) to Total (op.) 60%, GdF Suez Norge (20%) (later ENGIE and currently Neptune Energy) and Petoro (20%) with a commitment to reprocess 3D seismic and drill a well before February 2016 (**Figure 1**). The acreage applied for extended more towards the north and further to the East. The eastern acreage was awarded as well in February 2012 to Total (operator 50%), Det Norske (30%) and Spring Energy (20%) (later Tullow Oil) as part of license PL619. In August 2015, a one year extension to drill the well was granted to better prepare the 1/5-5 Solaris well for the ultra HP/HT conditions.

The well was spud 24 February 2016 and end of operations was 20 September 2016, for a total of 219 days. The well cost was 165 M$. The well was a technical success with regards to safely drilling the deepest and highest pressure well on the Norwegian Continental Shelf. All HP/HT regulations were well prepared and respected. The well proved sand in the Oxfordian Ula Formation, but was found water-bearing, with indication of gas shows from Gas while Drilling and low saturation gas from Wireline Log Interpretation.

With the drilling of Solaris all commitments have been fulfilled. The next decision gate (BOK) is set for February 3, 2018. EXPLO/TEPN does not intend to concretize PL618 and recommends relinquishing the license.

Table 1 gives an overview of all the partner meetings held on the PL618 license.

Date	**Meeting**		
	EC	**MC**	**WM**
14.03.2012		x	
11.06.2012	x	x	
15.11.2012	x	x	
21.03.2013	x	x	
08.05.2013			x
25.06.2013	x	x	
19.11.2013	x	x	
25.06.2014	x	x	
25.11.2014	x	x	
11.12.2014			x
10.06.2015	x	x	x
18.09.2015			x
14.09.2015			x
20.11.2015	x	x	
09.12.2015			x
15.12.2015	x	x	
12.05.2016			x
09.06.2016	x	x	
11.11.2016	x	x	
08.06.2017	x	x	

Table 1 Overview of all license meetings held

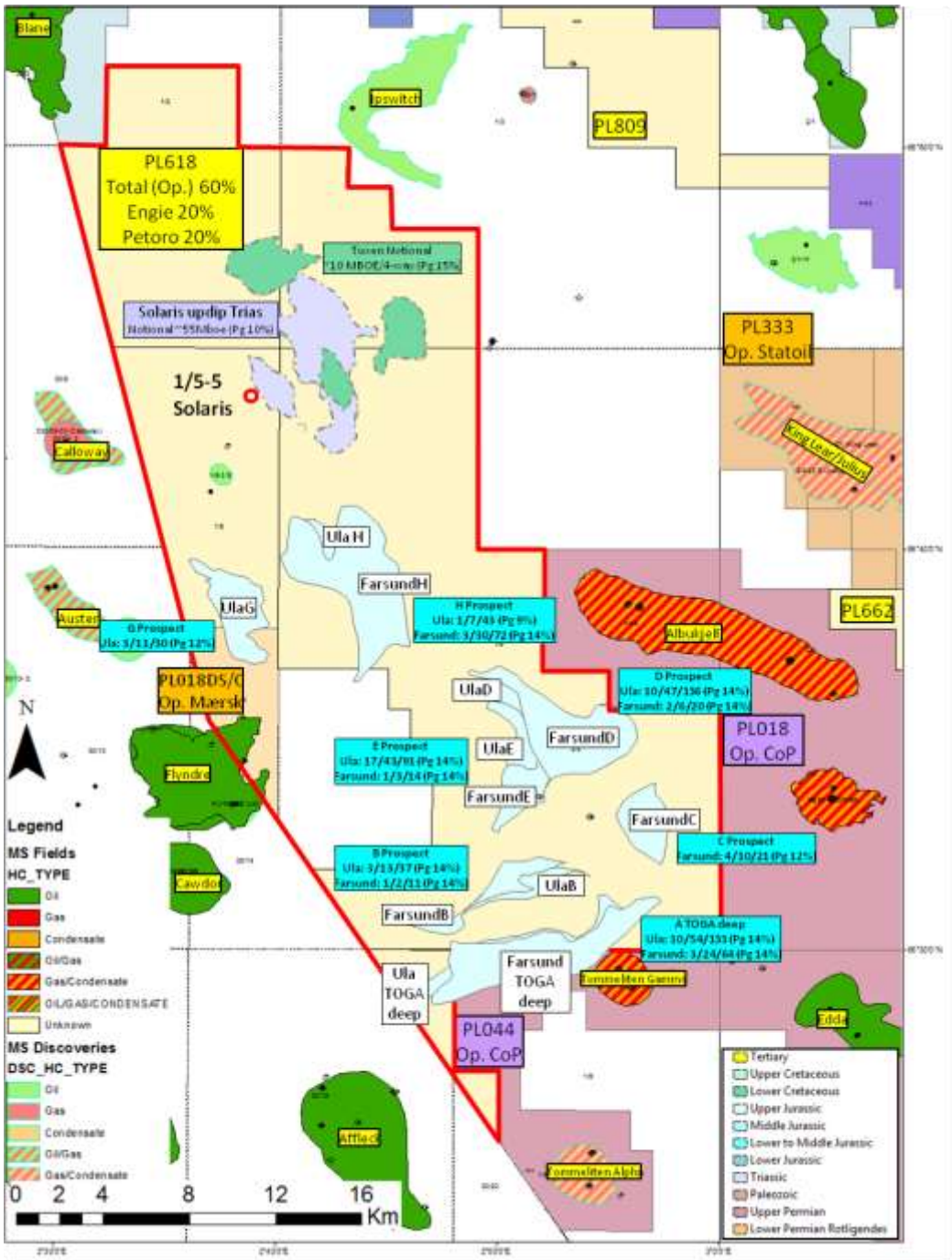

Figure 1. PL618 license location map

2. Database overviews

2.1. Seismic data

All the work performed on this license is based on following seismic data (Figure 2):

- Seismic survey VGCNS05 (DISKOS)
- Seismic survey TO1306R01, Total PSDM reprocessing of VGCNS05. The priority area was received in September 2013, and full volumes received in December 2013.

2.2. Well data

Well 1/5-5 has been drilled in PL618 to test the Solaris prospect. The key wells for the license and prospect evaluation were:

- **1/3-12S (NO Mandarin):** well drilled on the eastern flank of the Mandarin structure by BG in 2010, approximately 11km to the east of the Solaris well. The well proved presence of 81m gross sand thickness in J50 Ula Formation and was ended in the Triassic. The well was plugged and abandoned as a dry well. Main reason for the failure was the absence of hydrocarbon migration to the trap.

- **1/6-6 (NO)**: well drilled in 1993 by Norske Shell, approximately 22.5km to the south-east of the Solaris well. The well encountered 62m gross sand thickness in the Oxfordian J50 Ula Formation sands and was TD-ed in the Triassic. DST produced minor amount of gas and formation water. Main reason for the failure is seal breach.
- **1/6-7 (NO):** well drilled in 1992 by Conoco Norway, approximately 25km to the south-east of the 1/5-5 well. TD in the Jurassic (Oxfordian). The well encountered 98m gross sand thickness in Ula Fm, which was found water-bearing. Main reason for the failure is seal breach.

- **30/2a-6 (UK, Jackdaw):** drilled in 2005 by ConocoPhillips in the UK sector, on the western flank of the Eastern Central Graben, approximately 25km to the north-west of the Solaris well. It discovered gas/condensates in the Upper Jurassic J50 sandstones, which evolved from shoreface into turbidites. TD in Middle Jurassic.

- **30/8-3 (UK, Calloway):** drilled by BG in 2006, approximately 9.5km to the west of the Solaris well. TD in Triassic, gas-condensate bearing in the Heather, Upper Jurassic Jacqui Fm (J50 Ula Fm equivalent), Middle Jurassic Pentland Fm and Triassic Josephine Fm.

- The **1/5-5 (NO, Solaris)** well was spud 24 February 2016 on the ultra HP/HT Solaris prospect, the well was plugged and abandoned on 14 September 2016 as a dry well. The well was drilled down to the Middle Jurassic Bryne Formation. The well targeted the Oxfordian Ula Fm shoreface sandstones. It encountered 80m gross thickness of water bearing sandstone with 14% porosity and very low permeability from pressure measurements, with a reservoir conditions of 194 ˚C and 1250 bar. The main risk, seal breach, has been identified as the main cause of failure of this prospect.

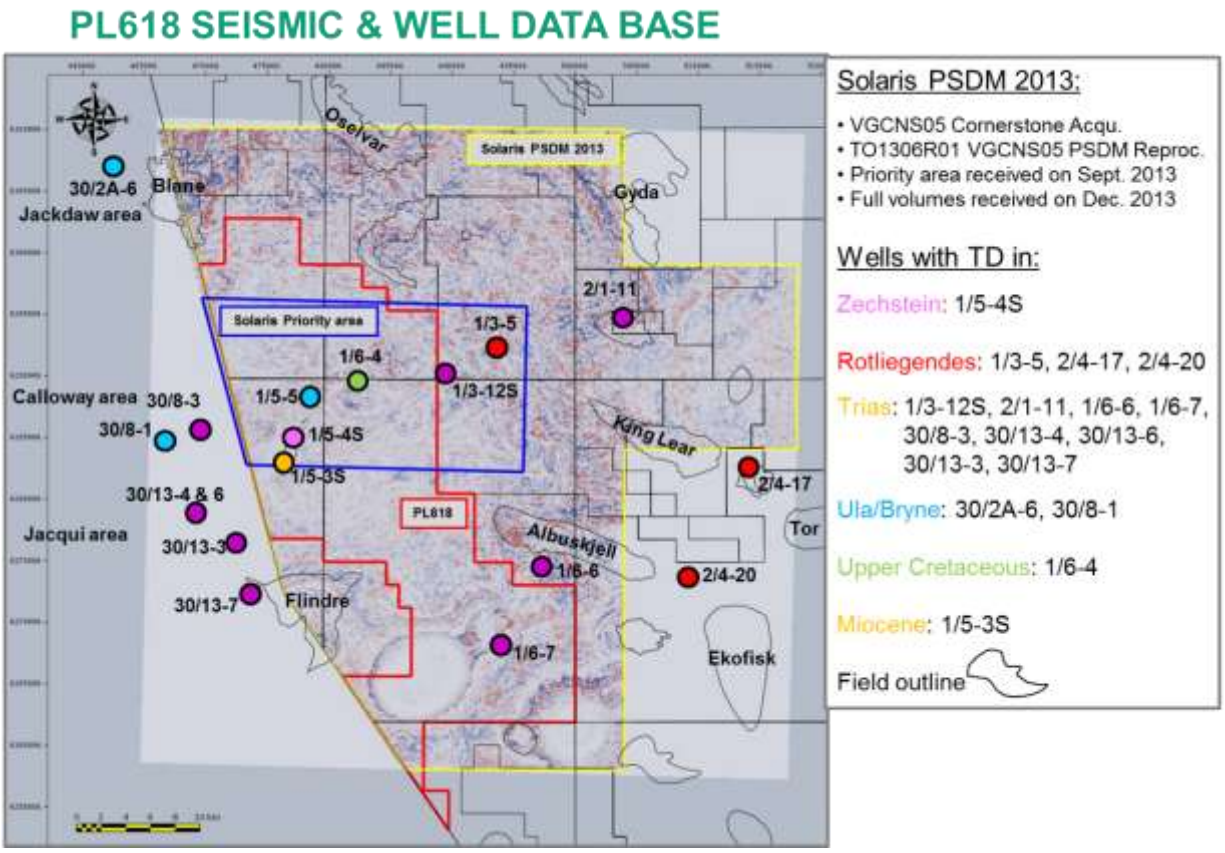

Figure 2 Seismic and well database

All wells used for the Solaris prospect and remaining prospectivity evaluation are given in Table 2.

Well NO	NPDID	TD
1/3-12S	**6260**	**Trias**
1/3-5	223	Rotliegendes
1/5-3S	3257	Hordaland
1/5-4S	4521	Zechstein
1/5-5	**7874**	**MJ Bryne Fm**
1/6-4	242	UC Tor
1/6-6	**1839**	**Trias**
1/6-7	**1928**	**UJ Ula**
2/1-11	2699	Trias
2/4-17	1792	Rotliegendes
2/4-20	5556	Rotliegendes
Well UK		
30/2A-6		Jur Vestland eq
30/8-1		Jur Vestland eq
30/8-3		**Trias**
30/13-3		Trias
30/13-4		Trias
30/13-6		Trias
30/13-7		Trias

Table 2 Well database.

The key wells highlighted in the table are explained in the text.

3. Results of geological and geophysical studies

The Geological and Geophysical studies completed are the following (Table 3):

Date	Action or Study
02/2012	PL618 Award
02/2012	Kick off CGG05 PSTM Reprocessing to PSDM, finalized 12/2013
03/2012	First license meeting
07/2012	Approval of work program by partnership
08/2012	Launched Upper Jurassic Paleogeographic interpretation, finalized 10/2014
08/2012	Petroleum system analysis draft (Total internal), updated 09/2012
09/2012	Pore Pressure Prediction study Total internal launched, finalized 11/2012
09/2012	Overpressure from Deltastack Total internal launched, finalized 11/2013
09/2012	Geomechanical modelling of fracturation curve Total Internal launched, finalized 11/2013
09/2012	Kick off initial Status of Requirements, updated #2 finalized 02/2016
01/2014	Kick off Structural excellence study, finalized 06/2014
03/2014	Finalized Petroleum system analysis, updated after new seismic interpretation after reprocessing
03/2014	Kick off Regional Biostratigraphy and Geochemistry study By Robertson/CGG, finalized April 2015
06/2014	Finalized PPP after new seismic interpretation after reprocessing
09/2014	Kick off Regional Fluid Inclusion Study, finalized December 2014
09/2014	Launched drilling fluid and cement study, finalized end 2014
09/2014	Launched Downhole tools study, finalized end 2014
09/2014	Launched Conductor analysis
09/2014	Launched use of MPD (managed pressure drilling) system study
09/2014	Launched Blow Out and Relief study
09/2014	Launched shallow hazard assessment
12/2014	Finalized well design with 20K BOP instead of 15K, to minimize risk on well
01/2015	Launched oil spill contingency study
01/2015	Launched blow out contingency plan, finalized June 2015
01/2015	Launched kick model study with Drillbench
01/2015	Launched Wellcat file validation and verification by HQ
12/2015	Held Drilling Well on Paper with partners
02/2016	Spud Solaris well 1/5-5, completed 09/2016
08/2016	Gas While Drilling study
10/2016	Launched cuttings quality assessment
10/2016	Launched post well study: petrography
10/2016	Launched post well study: thin section analysis of cuttings for diagenesis, finalized 05/2017
10/2016	Launched post well study: Rockeval, finalized 04/2017
10/2016	Launched post well study: Fluid Inclusion, finalized 03/2017

Table 3 Action or studies performed on PL618

Prospect evaluation studies (between 2012 and 2015) focussed on geological understanding of the reservoir, charging and pressure range of the Solaris prospect. The studies were updated after the reprocessing and new seismic interpretation, including structural backstripping, of the Solaris prospect.

Pre-drill studies (2015) were performed to minimize the risk of this ultra HP/HT prospect. The well was a record well on the Norwegian continental shelf, with a depth of almost 6000m. No major incidents or operational lost time was recorded while drilling.

Post well studies (2016-2017) on source rock, fluid inclusions and petrography show that the source rock above the reservoir has low S2 values and is not expected to expel large quantities of hydrocarbons. The fluid inclusion study shows that hydrocarbons have migrated, most likely from a local source and in very low quantities. The source rock time equivalent to the Ula Fm sandstones is therefore not thought to be of good quality, and downward migration is expected to be minimal.

Post well studies on petrography of selected cuttings showed that the Ula Fm sandstones are composed of relatively clean quartz arenite, fine to medium grains, moderately well sorted. The reservoir quality from log interpretation showed 14% porosity, but MDT pressure analysis indicated a very low permeability.
The macro porosity is, however, dominated by secondary porosity from grain dissolution. The pores are poorly connected, in line with the MDT analysis. The quality of the reservoir is mainly controlled by mechanical compaction, minor carbonate cementation and relatively low quartz cement, possibly caused by micro quartz coating.

The reservoir has shown pressures slightly higher than the predicted commitment case. This proves transfer of pressure from the connected deeper basin. If a gas column is present in the well there is only 2.5 bar difference between the reservoir pressure at the crest and the fracture closure pressure (FCP). The vertical seal capacity is therefore believed to be the main cause of failure of the Solaris prospect.

4. Prospect update

After the drilling of Solaris the prospectivity of the block was re-evaluated. The primary prospectivity of the license is in the Jurassic, but prospectivity has also been screened from seabed down to basement. The variety of petroleum plays within this prolific graben is shown in Figure 3.

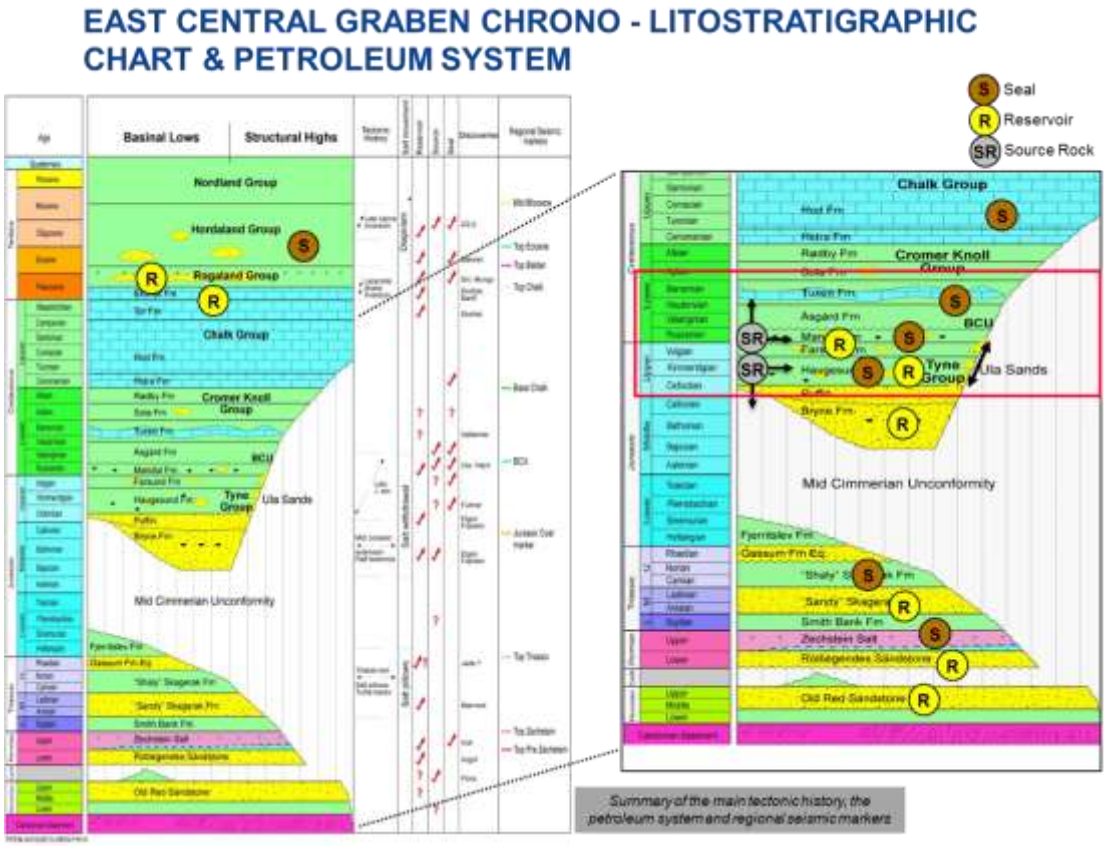

Figure 3. Petroleum Systems Chart Eastern Central Graben

Comparison to the APA 2011 several changes occurred (Figure 4 in comparison to Figure 1). Lead A name changed to Magpie and was discarded after drilling Solaris, because it was too deep. Leads. Leads B and H are currently notional updip Solaris Triassic leads. Lead D has become three notional Lower Cretaceous Tuxen Fm leads. Lead M was renamed to Grenadine, and is now called Prospect G. Lead N eastern side has evolved to prospects D and E. Lead C northern part is called Prospect B and southern part Prospect TOGA (Tommeliten Gamma) Deep. Prospects C and H have been added to the prospect inventory. Prospect C is an Upper Jurassic Farsund Fm turbidite target. Prospects G, H, D, E, B and TOGA Deep are combined Upper Jurassic Farsund Fm turbidite and Ula Fm shoreface targets.

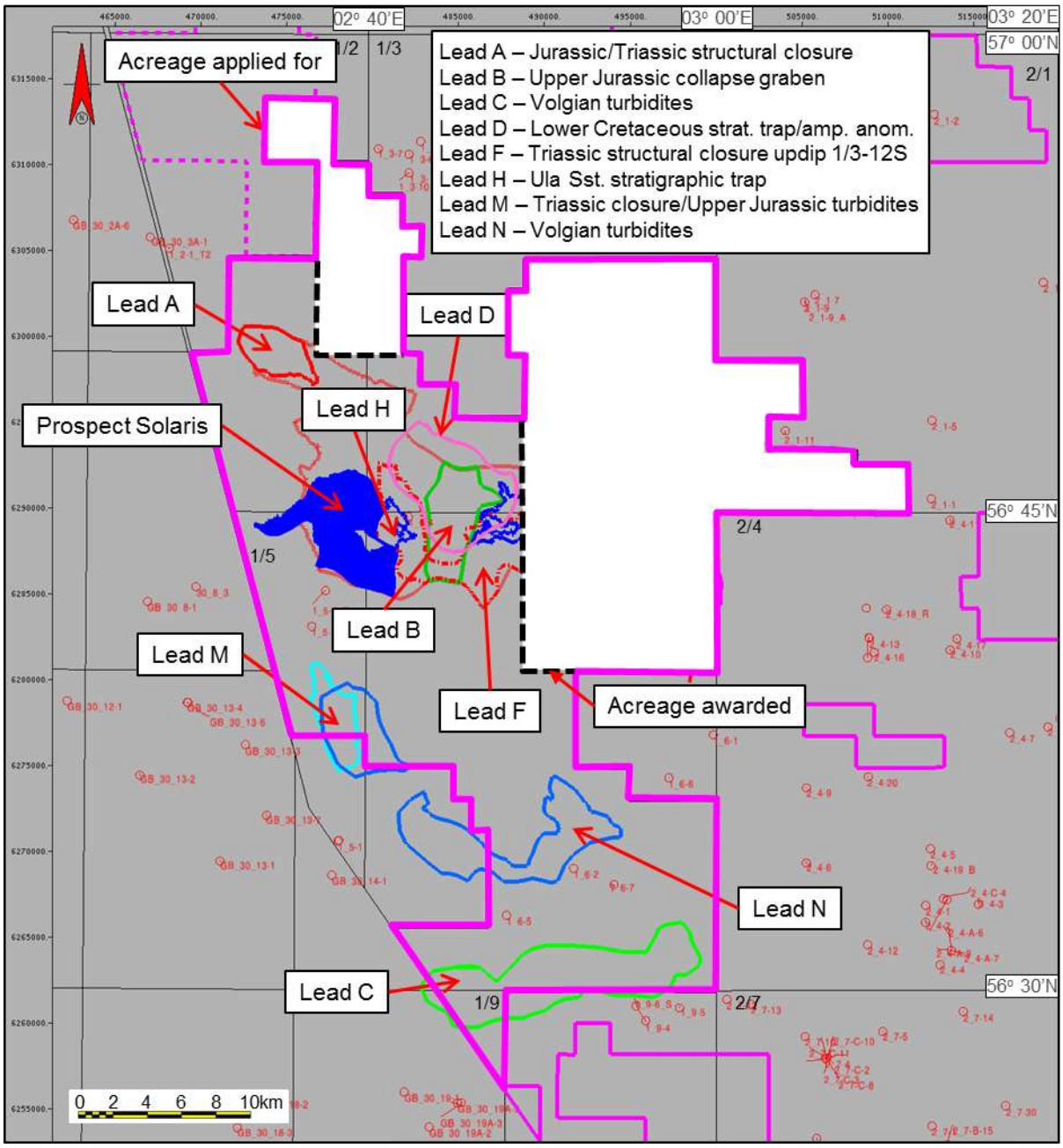

Figure 4 APA2011 Prospect and Leads identified within the area applied acreage

Sea-Bed to Upper Cretaceous: No prospectivity has been identified in the Upper Cretaceous to Sea bed interval. All structures have been already drilled and found dry or with small updip prospective volumes. AVO analysis doesn't support any other type of trapping.

Lower Cretaceous: The Lower Cretaceous Tuxen carbonate Fm could act as a fluid conduit (**Figure 2**) and is a reservoir in the Valdemar Field in Denmark. Three undrilled closures (<10km^2) north-east of the Solaris well on the Mandarin terrace have been identified in this interval. Considering the burial and the very low permeability, a small recovery factor is expected from this potential reservoir in PL618. Notional volumes of ~10 Mboe per structure are considered.

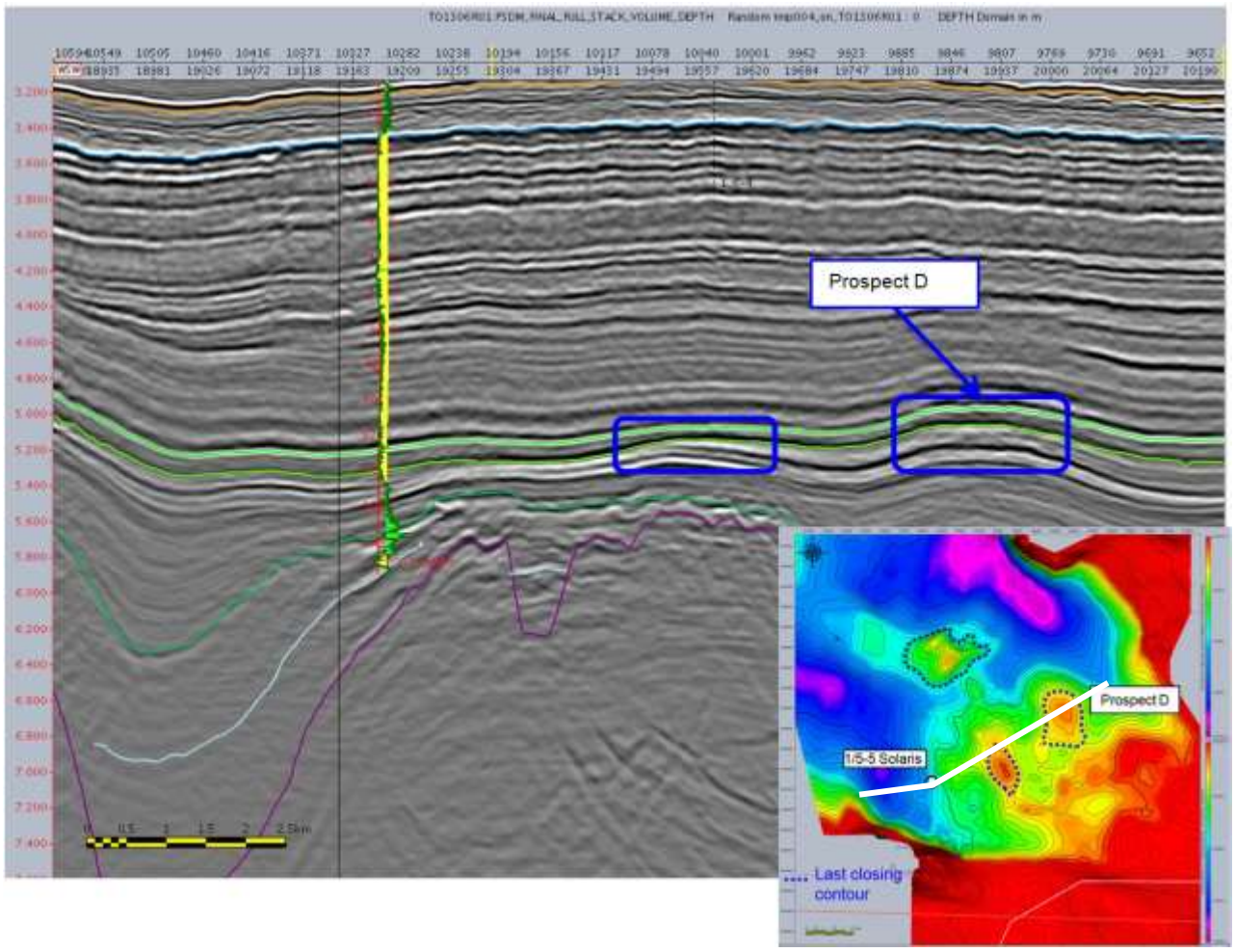

Figure 5 : Lower Cretaceous Tuxen prospectivity

Jurassic:

All the evaluated prospects comprise one or two objectives (segments), which can be either the Upper Jurassic Ula shoreface sandstones or the Upper Jurassic turbiditic sandstones of the Farsund Fm, or both. The location and mean recourses are given in **Figure 1**.

Farsund Turbiditic sandstone play:

This play is not as outspoken as not much sand has been found in this formation. Wells 1/6-6 and 1/6-7 did not encounter any sand in the Farsund. The Solaris well did find a thin and very tight sand with a gas peak while drilling, no pressure data could be collected. The Farsund objective is considered as a secondary target for the identified prospects in PL618. Reservoir presence is therefore considered to be the main risk.

Prospect	Crest TVDSS	Spill TVDSS	Condensate MBbls MEAN	P90	P50	P10	Gas Gm3 MEAN	P90	P50	P10	Total MBOE MEAN	P90	P50	P10	Pg
Farsund A TOGA Deep	4860	5660	10,50	1,20	8,10	23,30	3,10	0,40	2,60	6,80	29,70	3,40	24,20	64,00	14 %
Farsund B	4900	5660	1,50	0,20	0,80	3,80	0,40	0,10	0,20	1,20	4,20	0,50	2,30	10,90	14 %
Farsund C	5650	6500	4,00	1,20	3,30	7,70	1,20	0,40	1,00	2,20	11,30	3,90	9,80	20,90	12 %
Farsund D	4690	5800	3,20	0,50	2,10	7,40	0,90	0,20	0,60	2,10	9,00	1,50	6,10	20,40	14 %
Farsund E	4600	5250	2,30	0,40	1,30	5,70	0,50	0,10	0,30	1,30	5,50	0,90	3,20	13,50	14 %
Farsund H	4950	6000	12,50	1,10	10,20	26,60	3,70	0,40	3,20	7,70	35,10	3,30	30,60	72,60	14 %
Total Mean		Total Mean	34,00			Total Mean	9,80			Total Mean	94,80				
Mean Ave.		Mean Ave.	5,67			Mean Ave.	1,63			Mean Ave.	15,80				

Table 4 Estimated Resources of Farsund Fm Turbidite prospects remaining on PL618

Ula shoreface sandstone play:

All the prospects at the Ula level, except G, are controlled by (reverse) faults and steeply dipping closures against salt. The poor seismic imaging and the difficulty to image the salt flanks increase the uncertainty on the seismic picking and the risk on the geometry of the prospects.
Prospect G is a highly faulted prospect on the eastern edge of the Breiflabb basin.

Ula Sand wells matching Prospect	Crest TVDSS	Spill TVDSS	Condensate MBbls MEAN	P90	P50	P10	Gas Gm3 MEAN	P90	P50	P10	Total MBOE MEAN	P90	P50	P10	Pg
	Trias - 218m														
Ula TOGA Deep	5230	5810	22,40	3,40	18,50	46,60	6,90	1,10	5,70	14,20	64,10	10,00	54,20	132,60	14 %
Ula B	5300	5810	5,90	1,10	4,50	12,90	1,80	0,30	1,40	3,90	17,00	3,30	13,00	36,70	14 %
Ula D	5150	6060	21,50	3,30	16,20	47,60	6,60	1,00	5,00	14,60	61,70	9,70	47,20	135,80	14 %
Ula E	4910	5900	17,20	5,60	14,80	32,00	5,30	1,70	4,60	9,70	49,40	16,50	43,10	91,00	14 %
Ula G	4820	4990	4,90	0,90	3,70	10,70	1,50	0,30	1,20	3,30	14,10	2,60	10,90	30,40	12 %
Ula H	5690	5950	5,40	0,20	2,40	15,10	1,70	0,10	0,70	4,60	15,60	0,70	7,00	43,30	9 %
Total Mean		Total Mean	77,30			Total Mean	23,80			Total Mean	221,90				
Mean Ave.		Mean Ave.	12,88			Mean Ave.	3,97			Mean Ave.	36,98				

Table 5 Estimated resources of Ula Fm prospects remaining on PL618

The porosity is expected to range between 13 and 20%. The poorly connected pores, as seen in the Solaris well, increased the risk on low permeability's. However, the prospects are 600 to 800m shallower than the Solaris prospect. Wells 1/6-6 well test showed a kh of 702 mDm. Well 1/6-7 showed moderate to excellent permeability from FMT pressure analysis and excellent visible porosity from side wall cores.

Vertical seal capacity is expected to be sufficient. The overpressure on this side of the Breiflabb basin is anticipated to be in the range of 450 to 500 bar, whereas Solaris recorded ~650bar overpressure.
The basins to which the prospects are connected to, are less deep and a major fault running through the Breiflabb basin is thought to be a pressure cell boundary. Fill to spill could be considered (P10 contact) but the prospects displaying 3 way dip against faults and salt with highly faulted crests (TOGA DEEP, B, D, E and G), carry a significantly high seal risk.

Triassic:

Hydrocarbons are being produced from the Triassic on the Jasmine field on the J-Block (~4500mTVD) in the UK and from the Ula Field (~3750mTVD) located on the Sørvestlandet High. A study done on the Jasmine field showed a decrease in porosity of 5pu/300m (not taken major facies changes into account). Well 1/6-6 has a 10m core taken from the Triassic and showed <10% porosity and <<1mD permeability. No Triassic or older source rock is known in the license, and if there is no juxtaposition against upper Jurassic shales, no charging of hydrocarbons is expected.

Two Triassic prospects had been identified at the start of the license. It is however, after the drilling of the Solaris well these two are no more considered to be prospects.

- Lead A from the APA 2011 was later called Magpie. It shows a mega structure at Trias level and possible development of Bryne Fm. Following Solaris well results, the risk of charging has increased and reservoir quality is expected to be more downgraded.
- A Triassic fault block to the east of Solaris was interpreted to be charged for a possible spill of Solaris. This now does not seem feasible when looking at the results of Solaris.

Rotliegendes:

There is poor prospectivity at Rotliegendes level in PL618. A prospect would only be of interest if it is located in a favourable setting, allowing a working (lateral) migration path from a mature Kimmeridge clay kitchen to the trap (for instance a relatively shallow buried fault block juxtaposed against mature source rock of Upper Jurassic shales). In PL618 no such setting exists.

All the above mentioned prospects are of no economic value with the current lack of infrastructure to produce gas/condensate. They are not believed to become drillable prospects in the near future.

5. Technical evaluation

The remaining resources of the single prospects within PL618 do not allow for a stand-alone development. The Oljedirektorat have asked the owners of PL044 (Conoco Philips) and PL146/333 (Statoil) to look into the possibility to create a new gas processing capacity, to develop the gas and condensate discoveries of Tommeliten Alpha and King Lear, respectively, with an emphasis to create maximum value. A joint study from Conoco Philips, ENI, Statoil, and Total proposed 4 alternatives for a tie in solution to Ekofisk, which is most cost effective. A definite conclusion could not be made based on the results of the screening. Further studies are required to demonstrate feasibility, including a higher degree of technical and commercial maturity, both for field development costs and tie-in alternatives/cost.

If and when this gas hub is in place, smaller prospects could add value and reduce find to production time. Therefore, drilling an exploration well today will not be economically viable.

6. Conclusion

Grounds for full relinquishment of the PL618 license are the following:

- The license BoK deadline is 3 February, 2018.
- Main target, Solaris, has been found dry.
- The current status is that the area development ‘gas hub’ operated by Conoco Phillips (Ekofisk/Tommeliten) and/or Statoil (King Lear) will not be developed until there is capacity available on the Ekofisk platform
- Economic valuation shows that none of the prospects are material enough to be economical. These valuations are based on a tie-in to existing infrastructure.