May 2nd, 2017

Tankvegen 1
P.O. Box 40
Tananger, Norway
N-4098

To: Norwegian Petroleum Directorate

From: A/S Norske Shell on behalf of PL638 Partnership

Re: Final Licence Relinquishment Report for PL 638

Please find attached the required licence relinquishment report for PL638, submitted by A/S Norske Shell as "Operator" on behalf of the PL638 Partnership (Idemitsu, Petoro, Wintershall and DEA).

The report follows the guidelines as laid out for this reporting to ensure the NPD receives all the information necessary to consider the commitment closed out.

Please feel free to contact us if there are any questions or clarification required regarding the materials herein.

Respectfully yours,

[redacted]

[redacted]
PL638 Licence Manager Committee Chair
A/S Norske Shell
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RELINQUISHMENT REPORT FOR PL638

1. KEY LICENCE HISTORY

BG Norge AS was awarded operatorship of Production Licence PL638 on February 3rd, 2012 as a result of application in the APA 2011 Round in the North Sea. The operatorship of the licence PL 638 was transferred to AS Norske Shell when BG Norge was taken over by Shell late August 2016. The licence PL638, containing blocks 34/2, 34/3, 34/6, 35/1 & 35/4/5, is located in the Tampen Spur area of the Northern North Sea with a total area of 597.6 km^2 (Figure 1). The Shell operated Knarr FPSO (on-stream Q1 2015) is in tie-back distance to the licence. All PL638 partners with the exception of Petoro hold equity in the neighbouring PL373S Knarr asset. PL638 working interest is divided amongst the license awardees as follows:

A/S Norske Shell (Operator)	36%
Idemitsu	20%
Petoro	20%
Wintershall	16%
DEA	8%

PL638 licence application was made with the intent to secure prospective acreage next to the Knarr discovery, with the following firm work program:

- Perform relevant geological and geophysical subsurface studies
- Make Drill or Drop decision within 2 years

BG Norge recommended relinquishment of the licence in January 2016, but was voted into a licence extension application with partners driven by the desire to maintain exploration optionality and integrate upcoming offset well results into the licence prospectivity assessment (Uptonia well 34/6-4, released March 2nd, 2016 was dry).

A one year extension on the drill/drop decision was granted with the additional work program commitment:

- Integration of nearby exploration well results in the Geological and Geophysical evaluation
- Petroleum Systems study to understand the charge and migration efficiency from different source kitchens into the PL638 licence area

On handover to Shell, BG believed that the licence prospectivity was unattractive (high risk and low recoverable volumes). The oil leads are in downthrown traps and/or with significant charge risk (local Drake source challenged and prospects in migration shadow for charge from surrounding deep basins). The gas leads are deep, immaterial as stand-alone opportunities and potentially HPHT. An overview of the PL638 leads are illustrated in Figure 2.

Due to their high risk and lack of materiality, the leads have not been taken through Shell's full maturation process, although prior assurance by BG was conducted.

At the time of licence extension the Rognebær lead was seen as a material prospect but has since been downgraded to a lead. At the EC partner meeting in Sept 2016, Idemitsu shared their latest evaluation of the Rognebær lead, which confirms Shell's view that the structure is likely in a migration shadow for oil charge. Although BGs frame of Rognebær was as an oil prospect, Shell's regional basin modeling results suggest gas is the most likely phase (therefore not a tieback to FPSO candidate).

The leads Bjørnebær and Kirsebær are the closest oil leads to the Knarr field and were re-evaluated by Shell post transfer of operatorship. This evaluation resulted in downgrade of risks and volumes from the legacy BG evaluation. The seal risk was considered too high in the Bjørnebær lead and no hydrocarbon accumulation could be modeled in Kirsebær without a non-realistic bounding fault.

The subsurface evaluation has concluded that the prospectivity of PL638 remains low and therefore, the Operator, along with the partners, has decided to relinquish the licence.

Meetings held through the licence time are listed below with the separation between meetings held by BG and the last meetings held by Shell.

BG Norge AS

MC: (August 14th, 2012) – Initial licence startup meeting

MC: (March 5th, 2013) – Progress update on G&G studies and key prospects

EC/MC: (October 22nd, 2013) – Update on work program and a review of key prospects including Pliocene channels.

EC/MC: (June 25th, 2015) - G&G evaluations (seismic mapping, reservoir studies (Touchstone study) & petroleum systems (Drake source study) and prospect evaluation) and work program and budget.

EC/MC: (November 19th, 2015) - G&G evaluations – other formations, drill or drop strategy and work program and budget.

Working meeting: (January 25th, 2016) – Well failure analysis of 34/3-4A and 343-5, Heather and Drake Fm geochemistry study and Rognebær lead.

AS Norske Shell

EC/MC: (September 26th, 2016) – Workplan, scope of basin modeling

Working meeting: (December 13th, 2016) – Basin model and geochem study

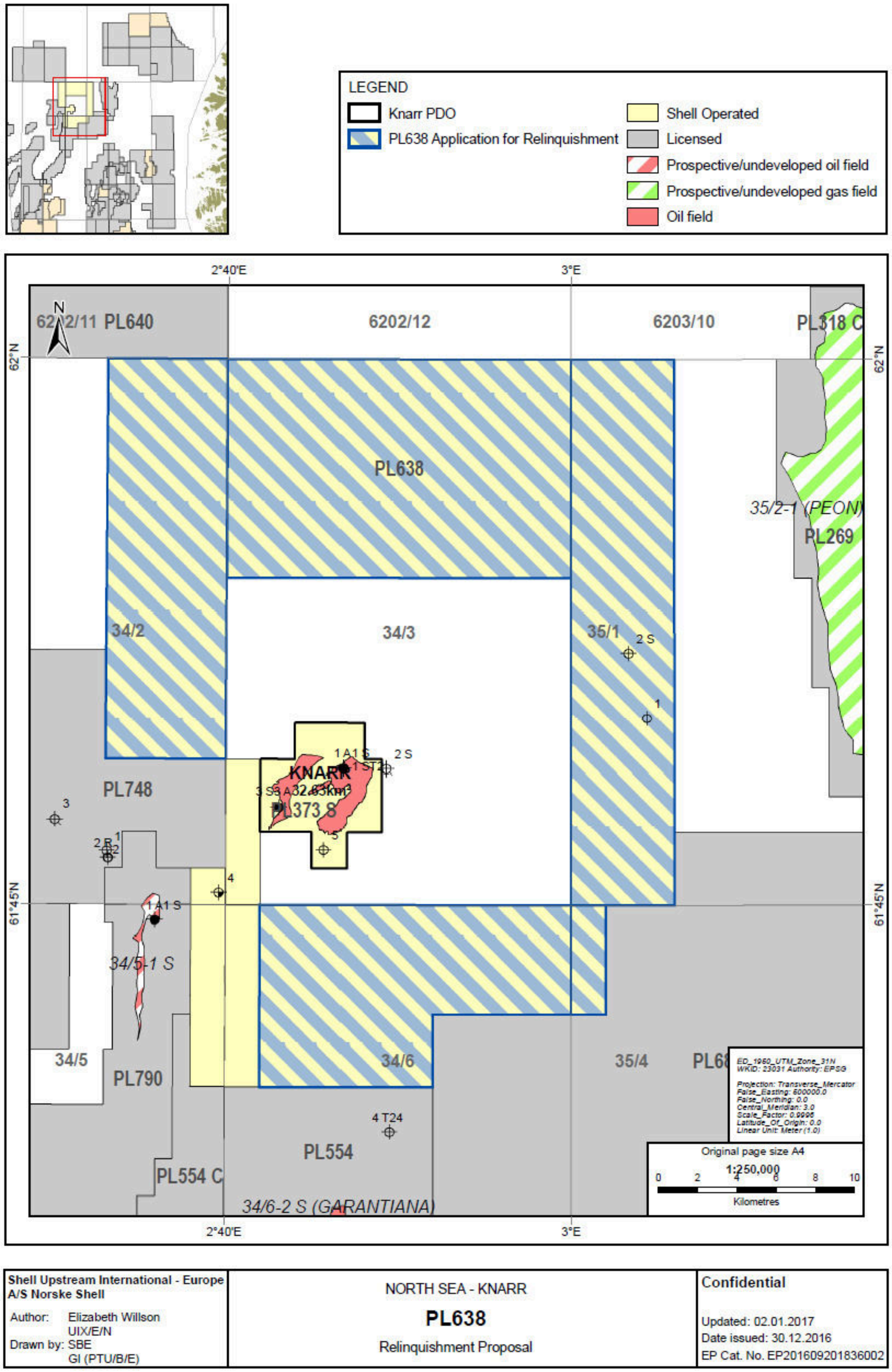

Figure 1. Location map showing position of PL638 relative to operated Knarr field.

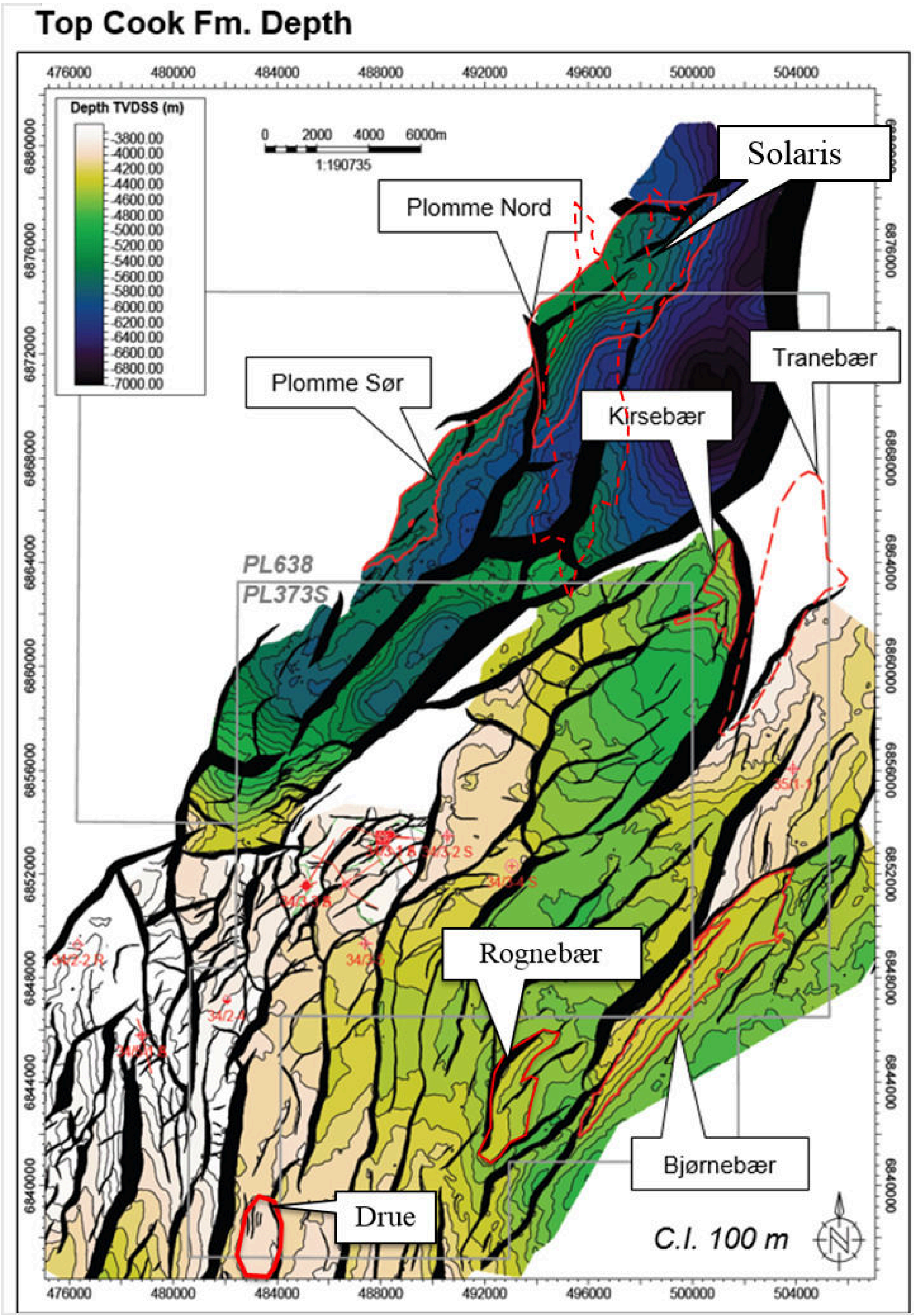

Figure 2: Location of leads in PL638.

2. DATABASE

Six 3D datasets were covering the PL 638 licence when granted; BG1102, bg06m01, mc3d-b34-6, mc3d-nvg-tampen (megamerge), mc3d-nns (megamerge) and mn9106m.
The earliest 3D seismic volume processed was the bg06m01 3D prestm volume also known as the Berries merge, produced by Geotrace in 2006, based on the merge of MC3D-MS97, MC3D-Q34 & MN9401 3D datasets. Later it was considered that this volume was not high enough quality for presdm processing and prestack inversion, had poor signal to noise ratio and coverage was not sufficient to fully evaluate the license. In 2011 a new 3D was acquired, the bg1102 3D volume which was later processed to prestm and presdm by Geotrace.
3D and 2D seismic surveys over the PL 638 licence are listed in Table 1 and shown in Figure 3 and Figure 4.

Table 1: List of seismic surveys covering licence PL 638.

Seismic Survey	3D	2D
BG1102	**X**	
bg06m01	X	
mc3d-b34-6	X	
mc3d-nvg-tampen (megamerge)	X	
mc3d-nns (megamerge)	X	
mn9106m	X	
nsr		X
tnw-92		X
mn9105		X
sg8043		X
n97		X

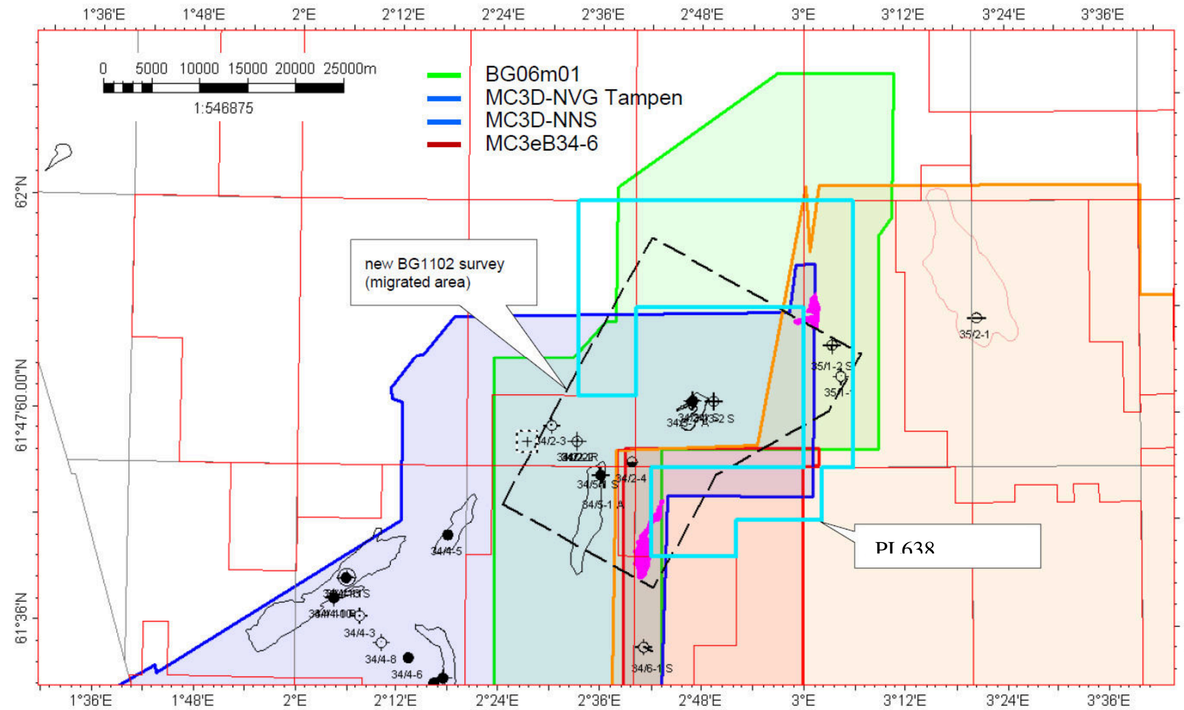

Figure 3: 3D Seismic serveys covering the PL 638 licence.

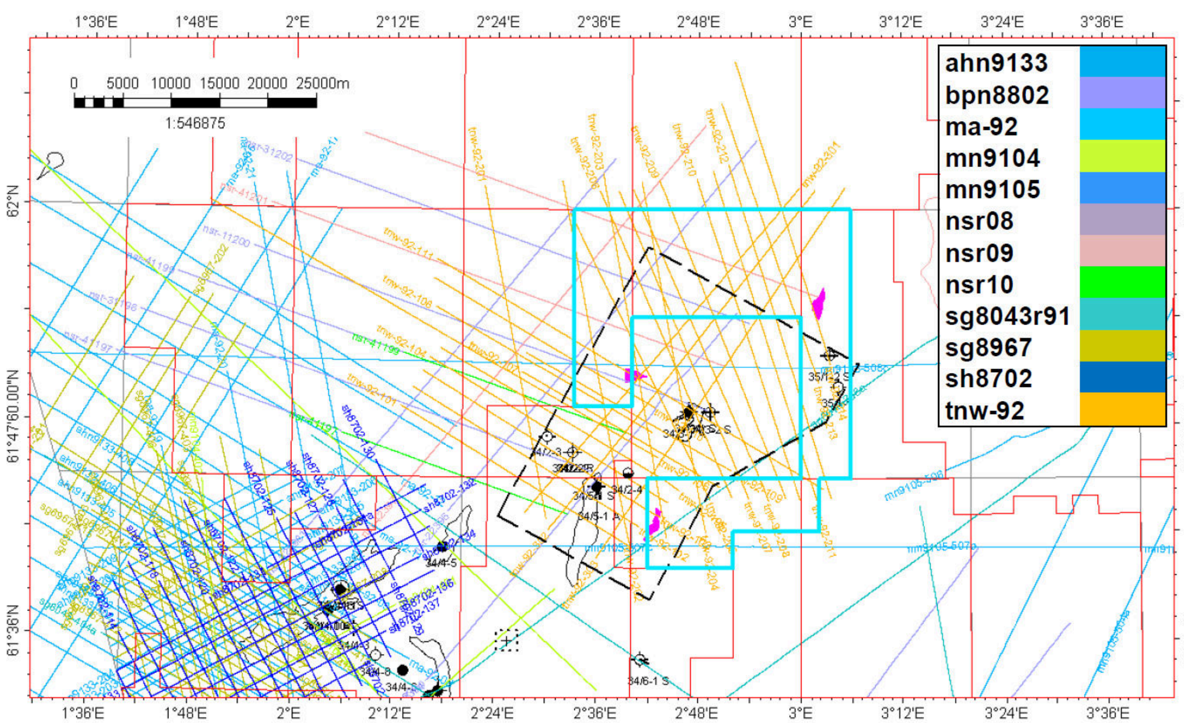

Figure 4: 2D seismic database covering the PL638 Licence.

Multiple successful wells have been drilled and resulted in the Knarr development between 2008 and 2015, proving the mid-Jurassic Cook Fm play in the area. 3 exploration dry holes have also been drilled in the near field, 2 by BG (34/3-5 and 34/3-4 A) and one by Total (Uptonia 34/6-4). Possible failure being a combination of source effectiveness and trap effectiveness (fault seal leakage). All wells used in the evaluation of this licence are listed in Table 2.

Table 2: List of all wells used for licence evaluation.

Wells	Year	Operator	Primary targets	Outcome
34/2-2 R	1980	Amoco Norway Oil Company	M. Jurassic Brent Gp and E. Jurassic Statfjord Fm	Dry
34/2-3	1981	Amoco Norway Oil Company	Sandstones below BCU	Shows
34/4-5	1984	Saga Petroleum ASA	Sandstones below BCU	Oil discovery (cemented)
34/2-4	1985	Amoco Norway Oil Company	Middle and Lower Jurassic sandstones	Oil shows
35/4-1	1997	Norsk Hydro Produksjon AS	Brent Gp	Shows
34/6-1 S	2002	Norske Conoco A/S	Jurassic Brent Gp, Cook Fm and Statfjord Fm	Dry
35/1-1	2002	Phillips Petroleum Company Norway	Jurassic Cook Fm and Statfjord Fm, Triassic Lunde Fm	Dry
34/3-1 S	2008	BG Norge AS	Cook and Statfjord sands	Oil discovery
34/3-1 A	2008	BG Norge AS	Cook and Statfjord sands	Oil discovery
34/3-2 S	2009	BG Norge AS	Cook and Statfjord sands	Dry
34/5-1 S	2010	BG Norge AS	Cook and Statfjord sands	Oil discovery
34/5-1 A	2010	BG Norge AS	Cook sands	Dry
35/1-2 S	2010	Statoil Petroleum AS E.	Jurassic sandstones	Dry
34/3-3S	2011	BG Norge AS	Cook sands	Oil discovery
34/3-3A	2011	BG Norge AS	Cook sands	Oil discovery
34/-6-2S	2012	Total E&P Norge AS	Cook and Statfjord sands	Oil discovery
34/3-4S	2014	BG Norge AS	Pliocene submarine canyon	Dry
34/3-4A	2015	BG Norge AS	Cook sands	Dry
34/3-5	2015	BG Norge AS	Cook sands	Dry
34/3-A-1H	2014	BG Norge AS	Cook sands	Producing oil
34/3-A-2H	2014	BG Norge AS	Cook sands	Producing oil
34/3-A-4H	2014	BG Norge AS	Cook sands	Producing oil
34/3-B-1H	2014	BG Norge AS	Cook sands	Injecting water
34/3-B-2H	2014	BG Norge AS	Cook sands	Injecting water
34/3-B-4H	2014	BG Norge AS	Cook sands	Injecting water
34/6-4	2016	Total E&P Norge AS	Cook sands	Dry

The various studies conducted to evaluate the prospectivity of PL638 is listed in table 3.

Table 3: Special studies used to evaluate the prospectivity of PL638

Studies	Source	Year
Paleoscan run and geobody extraction in the shallow section on BG1102	BG	2013
Rock physics in the shallow section on BG1102	BG	2013
Shallow Biostratigraphy (Neogene): 34/31-S, 34/3-2S, 34/3-3S, 34/5-1S & 35/1-1	Petrostrat	2013
FIS on Jordbær Sørøst and Jordbær Sør	Fluid Inclusion Technologies, Inc	2015
Biostratigraphy on Jordbær Sørøst and Jordbær Sør	Petrostrat	2015
Re-interpretation of reservoir (top Cook) horizon	BG	2015
Touchstone study	BG	2015
Drake fm source studies; 1. Regional Drake Fm and 2. Knarr area study	APT	2014
Heather fm source study	BG	2014
Basin model	Shell	2016
Geochemical study	Shell	2016

3. REVIEW OF GEOLOGICAL STUDIES

Cretaceous and Younger Plays:

Extensive geophysical studies were conducted to assess the prospectivity of the Miocene Channels. Paleoscan was run on the shallow section on the BG1102 volume to facilitate amplitude constrained geobody extraction. Follow-up rock physics studies were undertaken to evaluate amplitude and AVO anomalies further from 3D angle stacks. Results of this analysis showed that only amplitude (softness) and distance from the background AVO trend were useful indicators for reservoir presence and that AVO class is less useful on its own (lack of discernible gradient). No saturation discrimination was possible. This play was not pursued further due to high perceived risk of wet sands.

A biostratigraphic study was also conducted to inform the correlation of shallow channel bodies in the Neogene between 5 key Knarr area wells which were interpreted as gas filled. This play was not pursued further due to the limited size and volume potential of these sands as attractive drill targets.

Faulted Lower Jurassic Cook Play:

Following the drilling of Jordbær Sørøst (34/3-4A) and Jordbær Sør (34/3-5), a full prospectivity evaluation of the PL638 licences has been carried out, based on integration of the well results, re-mapping of the prospects and re-evaluation of all key risk elements (trap, charge, source, seal).

a. Trap/Seal

Significant refining and re-interpretation of the reservoir horizon (Top Cook Fm) has been completed, in several phases. Exploration mapping was initially done on the PSTM volume but for consistency with Knarr developments and the latest processing, the interpretation was migrated onto the PSDM with additional interpretation detail over the key leads/prospects.

b. Reservoir Quality

Touchstone modeling was conducted to reduced reservoir quality uncertainty and predict expected porosity and permeability in key leads/prospects. The main rationale for this work was the potential for reservoir quality degradation at burial depths exceeding 3500 m TVD. Analysis was focused on the Cook Formation, however additional modeling was also conducted on the Statfjord, which was under consideration as a potential secondary reservoir target. The results of the study can be summarized as:

- Depositional facies are a key primary control on reservoir quality in the Knarr area.
- Within Knarr, the best reservoir quality facies are the tidal channel complex (independent of diagenetic habit).
- West of Knarr reservoir quality decreases due to a decrease in grain size (additional silt and mud sized fractions).
- East of Knarr, the potential for porosity reduction via the quartz cementation increases.
- Facies stacking patterns can be used to predict facies and reservoir quality for prospects outside of the Knarr field.
- The effect of extended burial and higher temperature was modeled for deeper prospects to provide inputs for volumetric modeling.

c. ***Charge***

A series of charge related studies on the Drake, Heather and Draupne formations were conducted as the understanding of the regional and local charge mechanisms for the Cook Formation evolved with time. Early BG efforts focused mainly on the Drake and Heather which proposed a challenge due to their limited richness and/or maturity. Later petroleum systems modeling by Shell on behalf of the PL638 partnership discerned the Draupne and/or Heather to be the more viable source horizons for Cook opportunities.

APT conducted a Drake Formation source rock study in 2014 for BG comprised of 2 parts, a regional study and a Knarr area study. The regional study concluded that the Drake Fm is not a favorable source rock (lean kerogen, marginally mature) while the Knarr area study concludes the opposite. The presumed cause of contradictory results is related to problems with sample cleaning (oil-based mud contamination) and the lack of diagnostic biomarker signal for the Drake Fm.

Post drill FIS studies were conducted on the wet 34/3-4A and 34/3-5 wells to better understand local and regional migration pathways in the Cook Fm. The final report states that inclusions within the Cook Fm are classified as several to rare, which could indicate “a potential migration pathway”. Within 34/3-4A, FIS results indicate there is no paleo-oil column at the well location and no direct evidence of seal failure from pressure data. Similarly, FIS indicates that 34/3-5 had very little indication of hydrocarbons. Interpretation of these results suggests structure was not charged, therefore the failure mechanisms for both wells are thought to be a combination of source effectiveness and trap effectiveness.

With an emerging view that the Drake was not a viable source kerogen, BG conducted internal studies for the Heather Fm (alternative source) in support of the Jordbær South drilling proposal (2014). Based on pyrolysis data from the Jordbær Øst well (34/3-2S), the Heather Fm (Viking Group) within the Jordbær sub-basin was determined to have “fair to good” source potential for a gas prone source rock. APT classifies this kerogen as a Type III based on pyrolysis data and drill cuttings analysis observing a “predominance of woody organic material (vitrinite)”. This study was regional in scope and included wells throughout the Northern North Sea (Tampen Spur, Hordaland Platform, etc.). The lack of Type II kerogen indicators was problematic for Heather oil generation to charge PL638 oppportunities.

The workprogram requirement associated with the PL638 license extension in 2016 committed the partnership to conduct a basin model and geochemistry study. This requirement was driven by the view that despite the previous source-related studies, charge and migration into PL638 leads/prospects remained a critical technical risk to success. A poor technical understanding of this risk element in relation to a working prospect model was also evidenced by BG exploration failures in 2015 (34/3-5, 34/3-4A) and the more recent dry hole at 34/6-4 Uptonia (Total).

All of these wells appear to indicate insufficient charge which was not predicted by the earlier basin models. Historically, the Lower Jurassic Drake Fm was interpreted to be a fair to good source rock with oil potential, and believed to be the likely source for Knarr and Blåbær fluids as inferred from isotopic fingerprints and some minor biomarker differences with classic Draupne and/or Heather Fm derived fluids.

A new (2016) geochemical review of the source rock data, with additional scrutiny on sample contamination, isotopic and biomarker trends re-interprets the Lower Jurassic Drake Fm as a marginal source rock with mainly gas and some minor (at best) oil potential. Integration of screened fluid geochemistry data in combination with proprietary basin modelling demonstrates that Knarr (and Blåbær) are sourced from the Draupne Fm. Inter-basinal changes in organo-facies are cited as the cause of the observed geochemical variability. Basin model simulation shows the Draupne Fm to be marginally mature for oil at the structural crests (high points), oil mature on the flanks and towards gas mature in Marulk & Sogn basins. The Heather Fm shown to be gas mature in Marulk & Sogn basins, related to depth and kerogen type. An additional late phase (post-Cretaceous) pulse of charge along the Knarr ridge from the Marulk basin is interpreted to explain the high mature API's observed at Knarr relative to other regional accumulations. From the basin model study, simulated accumulations and migration pathways at lower Jurassic Cook Fm level are shown in Figure 4.

The conclusion for PL638 is that sufficient charge is available to fill viable traps and that the charge for most (depending on depth) is oil.

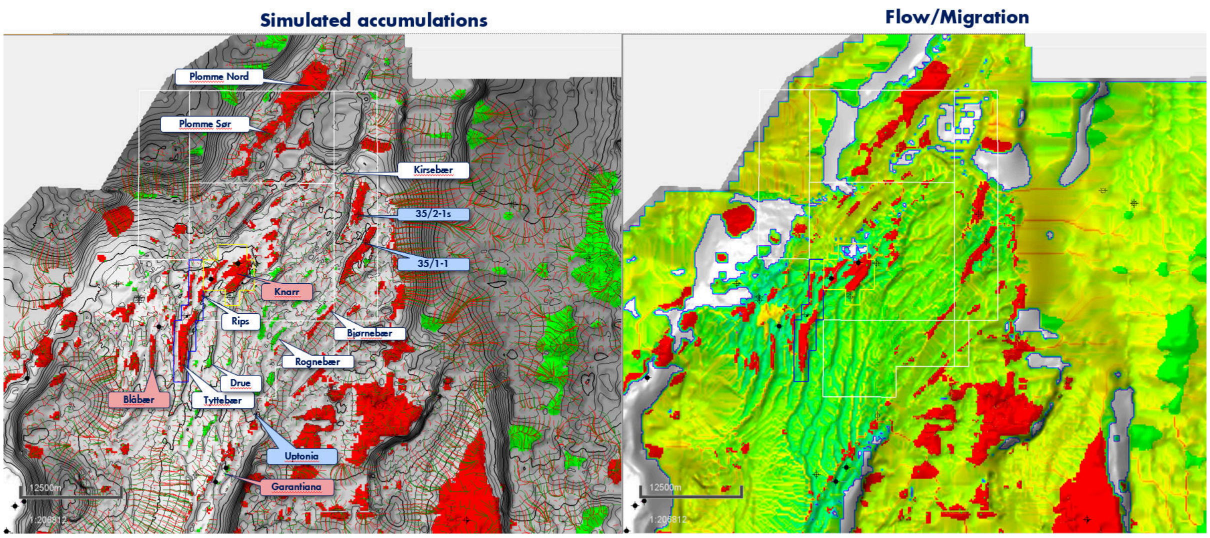

Figure 4: Simulated accumulations and migration pathways at lower Jurassic Cook Fm level.

4. PROSPECT UPDATE

The two prospects (Drue and Kirsebær) presented in the original licence application have been downgraded to leads through significant post-award technical evaluation due to high level of technical risk and limited attractiveness associated with small volume potential. Drue has also reduced in size, so the prospect is no longer inside the PL638 licence area. A number of conceptual leads including Morell (Upper Jurassic stratigraphic trap) and Beach64 (Cretaceous stratigraphic pinchout) listed in the application, as well as leads defined at licence award (Markjordbær, Einebær, Teiebær), have not matured into prospects. Despite a large amount of technical study, the interpretation has a similar outcome – none of these opportunities offered an attractive volume prize with a chance of success high enough to substantiate a viable prospect worthy of a drill decision.

The leads mentioned further in this chapter have been assessed by BG Norge up until the transfer of operatorship in August 2015, with Kirsebær and Bjørnebær seeing further evaluation by Shell in 2016 as these were the candidates for a larger volume prize. The Kiresbær and Bjørnebær leads are therefore listed in the prospect tables at the end of this chapter. The location of the leads mentioned below are shown on the map in Figure 2. The leads are split between 3 different plays: Pliocene channels, and the faulted Lower Jurassic Cook Formation and Statfjord Formation plays.

Pliocene channels

Solaris lead: This lead included multiple Pliocene channels with an enrolled CoS of 0.64 with the risks being the same for all channel bodies. The key risk for the lead was source effectiveness/hydrocarbon phase, due to the uncertainty of generation and migration of biogenic gas from deeper horizons that are in the biogenic window. Further south on PL638, amplitudes were observed suggested hydrocarbon saturated sands and supported a higher confidence on trap and charge. Based on these observations, the Pliocene play was tested at 34/3-4S, following an unsuccessful penetration of the Cook Fm in the main hole (34/3-4A). The key risk (source/charge) was confirmed both for the play and at the well location as no indications of hydrocarbons were present. The cause of the amplitude effect has not been revisited but is presumed to be driven by lithology alone, not fluid fill.

Statfjord play

Tranebær is a Statfjord lead with a configuration whereby the overlying Cook Fm is eroded by the BCU. A potential gas chimney is observed above the structure indicating hydrocarbons leaking from the structural high. Erosion associated with the BCU is interpreted to have also removed a portion of the Statfjord Formation, therefore the prospect has 3 risk elements: reservoir presence, reservoir quality and trap viability.

Trap closure to the north is difficult to confirm due to low signal in the seismic data. Reservoir presence is an uncertainty because the surfaces cannot be confidently mapped and are only mapped in by isochrons from a known horizon (top Cook) on a regional basis. Reservoir effectiveness is a key risk because Nansen Member reservoir quality could be affected by the erosion surface (porosity and permeability degraded associated with subaerial exposure). If the Nansen is fully or partially eroded, the limited calibration and apparent heterogeneity of the underlying Eiriksson Member also presents a reservoir quality risk.

Based on this interpretation, the risk of closure is high and even if a viable trap exists, the preserved section is unlikely to possess sufficient reservoir storage and deliverability to support an economically attractive prospect.

<u>Lower Jurassic play</u>

Play Overview

Reservoir Presence: Paleogeography of the Cook Fm was originally interpreted by BG as a tidal estuary to shoreface depositional environment within the Knarr area. Locally within the Knarr field, the formation is split into 5 sands using Charnock's (2001) maximum flooding surfaces (except top of sand 2). These sand bodies are informally grouped into the Upper and Lower Cook by an intraformational maximum flooding surface (MFS). Deposition of Lower Cook sands was dominated by tidal influences, with tidal bar and tidal channel facies most common. The Upper Cook sands were deposited in a wave dominated environment, with preservation of a more typical shoreface progression with lesser tidal modulation. There is high confidence correlation of the individual sands within the Knarr field, with sand thickness decreasing significantly to the west. To date, the detailed reservoir understanding from the Knarr field has not been linked and integrated into the regional context. This is made difficult due to sparse well penetrations outside of the field area and uncertainty around the mechanism(s) of offset well failures.

Reservoir Quality: High porosity preservation seen in the Knarr field is due to chlorite coating of sand grains which prevents later quartz cementation (and pore occlusion) associated with burial diagenesis. The ability to predict the presence of chlorite coating and therefore reservoir "sweet spots" in the near-field area and into PL638 is limited, despite a linkage to tidal depofacies.

Seal: Overall fault seal is seen as a high risk due to the fact that trap analogues in the Tampen Spur are interpreted to have failed due to fault leakage (ie. Blabaer 34/5-1S). Many sand-on-sand juxtapositions are present on faults bounding Cook Formation structures which present potential leak points, either Cook on Cook, or Cook on Statfjord. Top seal is not considered a risk due to the generally thick section of overburden containing shale, in either the Upper Jurassic and/or on top of the BCU.

Source: Overview addressed under study section. Access to migration/charge determined on a local basis.
Trap: Defined on an individual prospect/lead basis.

Following are the prospects and leads which have been evaluated the lower Jurassic (Pleinsbachian) Cook Fm in the Dunlin group.

Opportunities Evaluated

Drue lead is a relatively flat structure down-thrown from 34/2-4 well with only a small part of the closure extending downdip into PL638. It is defined by a continuous, well-defined top Cook Fm reservoir reflector with some internal faulting. The reservoir parameters are interpreted to be similar to Knarr Vest. From the evaluation conducted by BG, the only available source was believed to be the Drake Fm which carries significant risk due to the low relief of the structure and potentially similar failure mechanism as Jordbær Øst. New understanding of the charge model in this area predicts the Draupne as the main source kerogen, and that the prospect would be gas filled. There is a potential for Cook-Cook juxtaposition along southern fault, constraining the volumes to a small 4-way structural closure. Overall the Drue lead is viewed as being a high risk lead with too low volume prize (and the wrong phase) to be economically attractive. The key risk would be charge (phase) as gas cannot be tied back to the Knarr FPSO and would require volume to support a stand-alone development solution.

The **Rognebær** lead is situated in a downthrown fault block that sits in a structurally low area between the Sturlason and Garantiana highs. It is believed to have good lower Jurassic Cook reservoir quality and a viable up dip seal (Heather and Brent Shales). The critical risk is viewed to be source effectiveness due to the charging mechanism, relying on juxtaposed Heather and overlying Drake Fm, and associated well failures of 34/3-4A and 34/3-5. From the understanding of the new regional basin model also Rognebær has gas as the most likely hydrocarbon phase which cannot be tied back to the Knarr FPSO.

The Plomme Sør lead has a partial fault closure to the northwest and partial BCU truncation. The lead is very deep (>5000 m TVD) heavily faulted and compartmentalized. **The Plomme Nord** lead is similarly deep with a three-way fault closure with dip closure to the northeast, down-dip of Jordbær Øst and Sørøst. There is a challenging seismic tie of Cook Fm back to Knarr and therefore Cook may not be present in portions of these structures. Reservoir is along strike to Knarr West and Knarr Sentral. The greatest uncertainty associated with both leads is the effect of burial diagenesis on reservoir quality at depths greater than 4000 m TVD. Modeling suggests some degradation is likely, but reservoir properties should still be adequate to support commercial flow rates. Based on BG`s basin model, source possibilities include Drake Fm, Heather Fm and Draupne Fm. The quality of Heather and Draupne Fm on the hanging wall (north of Knarr field) is unknown. The leads have juxtaposition with Heather in individual fault blocks and they are also overlain by the Drake Fm shales. Reflectors are challenging to map with multiples and other noise, resulting in the uncertainty on trap, related to the position of the BCU and the required presence of overlying Cretaceous sealing lithologies. The leads need the trap to seal against the BCU up dip with no thief beds present in the Cretaceous section. An additional consideration for these leads is that reservoir conditions are most likely HPHT (high temperature and high pressure) which carries a significant increase in CAPEX to drill and develop safely. Given the high degree of trap and reservoir quality risk, high cost to development and likelihood of gas, the leads did not support further maturation to a drill candidate.

Bjørnebær and Kirsebær are the two leads with significant technical scrutiny post transfer of operatorship from BG Group to Shell. The Cook Fm play segment containing these two leads is unproven as Knarr and Garantiana are interpreted to access different source kitchens/migration pathways than Bjørnebær and Kirsebær. PL638 is also less calibrated by wells, therefore a wider (regional) range has been captured in reservoir quality inputs for volumes, and a recovery risk has been applied to represent observed permeabilities in offsets that will not support commercial oil flow rates. There is partner alignment on the limited attractiveness of these leads. NPD prospect table for both Bjørnebær and Kirsebær can be found in table 4 and 5 respectively.

Bjørnebær lead is an elongate structure defined by one bounding fault and 3-way dip, and it is positioned downdip from 35/1-1. Trap effectiveness is considered as the main risk, primarily due to the absence of a clearly defined structure relative to the 35/-1 ridge. Furthermore, there is potential juxtaposition of Cook on Cook or/and against Statfjord or Triassic sands. In addition, the Cook may be eroded at a horst along the crest, representing a potential breach/leakage point for the trap.

Kirsebær lead is a downthrown structure on the edge of the regional Sturlason High, with a dip closure against a main bounding fault to the east. The lead is positioned at the junction of multiple seismic volumes and cannot be mapped on a single volume, thus introducing risk on the trap definition. Basin modeling suggests the migration into this vicinity is limited, with the lead only having access (if the trap is viable and faults are sealing) by local source (Drake).

Table 4: Bjørnebær, NPD prospect table

Block	35/1	Prospect name	Bjørnebær	Discovery/Prosp/Lead	Lead	Prosp ID (or New!)	NPD will insert value	NPD approved (Y/N)	
Play name	NPD will insert value	New Play (Y/N)		Outside play (Y/N)					
Oil, Gas or O&G case:		Reported by company	Norske Shell AS	Reference document				Assessment year	2016
This is case no.:		Structural element	Tampen Spur	Type of trap	Hanging wall fault t	Water depth [m MSL] (>0)	400	Seismic database (2D/3D)	3D
Resources IN PLACE and RECOVERABLE		**Main phase**				**Associated phase**			
Volumes, this case		Low (P90)	Base, Mode	Base, Mean	High (P10)	Low (P90)	Base, Mode	Base, Mean	High (P10)
In place resources	Oil [10^6 Sm^3] (>0.00)	3.63	152.28	30.85	65.66				
	Gas [10^9 Sm^3] (>0.00)					0.08	0.51	0.65	1.39
Recoverable resources	Oil [10^6 Sm^3] (>0.00)	1.27	8.35	10.79	23.66				
	Gas [10^9 Sm^3] (>0.00)					0.05	0.30	0.39	0.85
Reservoir Chrono (from)	Toarcian	Reservoir litho (from)	Cook Fm	Source Rock, chrono primary	Kimmeridgian	Source Rock, litho primary	Draupne	Seal, Chrono	Toarcian
Reservoir Chrono (to)	Pliensbachian	Reservoir litho (to)		Source Rock, chrono secondary		Source Rock, litho secondary		Seal, Litho	Drake Fm
Probability [fraction]									
Total (oil + gas + oil & gas case) (0.00-1.00)	0.02	Oil case (0.00-1.00)	0.02	Gas case (0.00-1.00)	0.02	Oil & Gas case (0.00-1.00)	0.02		
Reservoir (P1) (0.00-1.00)	0.69	Trap (P2) (0.00-1.00)	0.06	Charge (P3) (0.00-1.00)	0.59	Retention (P4) (0.00-1.00)	0.99		
Parametres:	Low (P90)	Base	High (P10)	*Reservoir properties calibrated against Knarr asset parameters. Temperature and pressure from basin model.*					
Depth to top of prospect [m MSL] (> 0)		4140							
Area of closure [km^2] (> 0.0)	2.6	4.0	5.6						
Reservoir thickness [m] (> 0)	76	100	125						
HC column in prospect [m] (> 0)	73	120	150						
Gross rock vol. [10^9 m^3] (> 0.000)									
Net / Gross [fraction] (0.00-1.00)	0.75	0.86	0.94						
Porosity [fraction] (0.00-1.00)	0.13	0.17	0.22						
Permeability [mD] (> 0.0)									
Water Saturation [fraction] (0.00-1.00)	0.50	0.40	0.30						
Bg [Rm3/Sm3] (< 1.0000)									
1/Bo [Sm3/Rm3] (< 1.00)	0.77	0.74	0.71						
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)	121	132	147						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.30	0.35	0.40						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.05	0.06	0.07						
Recov. factor, gas main phase [fraction] (0.00-1.00)									
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)				For NPD use:					
Temperature, top res [°C] (>0)	130			Innrapp. av geolog-init:	NPD will insert value	Registrert - init:	NPD will insert value	Kart oppdatert	NPD will insert value
Pressure, top res [bar] (>0)	710			Dato:	NPD will insert value	Registrert Dato:	NPD will insert value	Kart dato	NPD will insert value
Cut off criteria for N/G calculation	1.	2.	3.					Kart nr	NPD will insert value

Table 5: Kirsebær, NPD prospect table

Block	35/1	Prospect name	Kirsebær	Discovery/Prosp/Lead	Lead	Prosp ID (or New!)	NPD will insert value	NPD approved (Y/N)	
Play name	NPD will insert value	New Play (Y/N)		Outside play (Y/N)					
Oil, Gas or O&G case:		Reported by company	Norske Shell AS	Reference document				Assessment year	2016
This is case no.:		Structural element	Tampen Spur	Type of trap	Hanging wall fault t	Water depth [m MSL] (>0)	405	Seismic database (2D/3D)	3D
Resources IN PLACE and RECOVERABLE		**Main phase**				**Associated phase**			
Volumes, this case		Low (P90)	Base, Mode	Base, Mean	High (P10)	Low (P90)	Base, Mode	Base, Mean	High (P10)
In place resources	Oil [10^6 Sm^3] (>0.00)	0.29	3.11	4.46	9.90				
	Gas [10^9 Sm^3] (>0.00)					0.01	0.07	0.09	0.21
Recoverable resources	Oil [10^6 Sm^3] (>0.00)	0.10	1.05	1.56	3.58				
	Gas [10^9 Sm^3] (>0.00)					0.00	0.04	0.06	0.13
Reservoir Chrono (from)	Toarcian	Reservoir litho (from)	Cook Fm	Source Rock, chrono primary	Kimmeridgian	Source Rock, litho primary	Draupne	Seal, Chrono	Toarcian
Reservoir Chrono (to)	Pliensbachian	Reservoir litho (to)		Source Rock, chrono secondary		Source Rock, litho secondary		Seal, Litho	Drake Fm
Probability [fraction]									
Total (oil + gas + oil & gas case) (0.00-1.00)	0.00	Oil case (0.00-1.00)	0.00	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	0.00		
Reservoir (P1) (0.00-1.00)	0.69	Trap (P2) (0.00-1.00)	0.11	Charge (P3) (0.00-1.00)	0.05	Retention (P4) (0.00-1.00)	0.93		
Parametres:	Low (P90)	Base	High (P10)	*Reservoir properties calibrated against Knarr asset parameters.Temperature and pressure from basin model.*					
Depth to top of prospect [m MSL] (> 0)		4325							
Area of closure [km^2] (> 0.0)	0.2	0.9	2.1						
Reservoir thickness [m] (> 0)	82	100	118						
HC column in prospect [m] (> 0)	90	200	314						
Gross rock vol. [10^9 m^3] (> 0.000)									
Net / Gross [fraction] (0.00-1.00)	0.63	0.76	0.90						
Porosity [fraction] (0.00-1.00)	0.16	0.19	0.22						
Permeability [mD] (> 0.0)									
Water Saturation [fraction] (0.00-1.00)	0.50	0.40	0.30						
Bg [Rm3/Sm3] (< 1.0000)									
1/Bo [Sm3/Rm3] (< 1.00)	0.77	0.74	0.71						
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)	117	122	123						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.30	0.35	0.40						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.05	0.06	0.07						
Recov. factor, gas main phase [fraction] (0.00-1.00)									
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)				For NPD use:					
Temperature, top res [°C] (>0)	130			Innrapp. av geolog-init:	NPD will insert value	Registrert - init:	NPD will insert value	Kart oppdatert	NPD will insert value
Pressure, top res [bar] (>0)	710			Dato:	NPD will insert value	Registrert Dato:	NPD will insert value	Kart dato	NPD will insert value
Cut off criteria for N/G calculation	1.	2.	3.					Kart nr	NPD will insert value

5. TECHNICAL EVALUATIONS

Knarr oil production is at projected plateau rate after ~ 2 years therefore capacity exists to bring on additional volumes thus providing motivation to prove up additional NFE (oil) opportunities. The operator has determined 12 mmboe as a minimum threshold volume to support a viable tie-back to the Knarr FPSO given a 5 km tie-back distance. This volume threshold is influenced by tie-back distance. Sensitivity testing suggests a maximum radius of 15 km from the FPSO with decreasing attractiveness (increasing minimum volume required). All leads identified are more than 5 km away from the FPSO.

Development of the Solaris (Pliocene channels) lead and other similarly shallow plays is also seen to be challenging from a pressure management and cost perspective, even if the phase were oil. To produce into the FPSO, the wells would have to be put onto compression immediately due to the normally pressured reservoir and lack of pressure support (only 1900-2200psi pressure). Solaris is more than 15km from the FPSO, making it expensive and infrastructure intensive to tie back. A reasonable depletion strategy would also require 2 or more development wells to access the majority of reserves due to the complex channel stacking patterns.
The most viable development of Plomme Sør and Plomme Nord would have to account for HPHT reservoir conditions, and a high likelihood of gas. Significant gas volumes would require a stand-alone solution, rather than tie-back to Knarr, and would require a larger volume prize to support the capital intensity required.

New understanding of the charge model in this area, predicting Draupne Fm as the main source, suggests gas is the main likely hydrocarbon phase for both Drue and Rognebær and therefore they are also not a tie-back candidates to the existing FPSO.

Finally, the two leads which might constitute the most likely tie-back candidates to Knarr (oil, within radius) are Bjørnebær and Kirsebær. Neither presents a compelling prospect based on their technical risk profiles (trap, charge, etc.), nor the potential volume prize associated with a success case scenario.

Based upon these conclusions, the partnership felt a conclusive analysis has been conducted on the NFE opportunities present within PL638 to determine that none are attractive enough to support a drill decision.

6. CONCLUSIONS

The prospectivity with licence PL638 has been evaluated both by BG and Shell.

With the licence extension in 2016, transfer of operatorship to Shell, and completion of a comprehensive petroleum systems study, a revisit of the remaining Cook Fm leads was completed. The high level of technical risk associated with each, confirmed that there were no attractive opportunities to propose as drill candidates and supported the final decision to relinquish the licence. Key risks of each are summarized as:

- Rognebær - Shell's regional basin modeling results suggest gas is the most likely phase (therefore not a candidate for tieback to the FPSO)
- Bjørnebær - Significant seal risk (fault, top seal)
- Kirsebær - No hydrocarbon accumulation could be modeled without including a non-realistic bounding fault

In conclusion, the main Lower Jurassic Cook prospects for this licence suffer from high technical risk and a lack of materiality to support an attractive drill opportunity. Two key risks are prevalent and condemning: fault seal and charge/migration.

The leads that are more likely gas charge are also consider high risk and not material enough to support the standalone development that would be required.

- The main risk for Solaris and the Pliocene channels leads was charge and/or phase. This is interpreted as the failure mechanism for well 34/3-4 S.
- The Tranebær lead (Statfjord play) is unattractive due to high reservoir (presence, quality) and trap risk.
- Plomme Sør and Nord located in the hanging wall to the north of Knarr have a trap, reservoir risk and charge (phase) risk. The reservoir is also likely to be HPHT, significantly increasing volume prize required for development sanction.

Having fulfilled the required work commitment related to the 2016 extension and based on the integrated results of the full technical evaluation conducted by both BG and Shell as operators, no attractive drill-worthy prospects have been identified on the licence. Therefore, the Operator, along with the PL638 partnership (DEA, Idemitsu, Wintershall, Petoro) unanimously support relinquishment of the licence.