PL 779 Relinquishment Report

Final version, 02.05.2016

VNG Norge Lundin Norway FORTIS PETROLEUM SUNCOR ENERGY

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VNG Norge

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1 Key license history

License award and licencees

PL 779 was awarded February 6th 2015 to a license group consisting of VNG Norge AS (operator, 40 % equity), Lundin Norway AS (20 % equity), Fortis Petroleum Norway AS (20 % equity) and Suncor Energy Norge AS (20 % equity). The 2014 Awards in Predefined Areas (APA) application was delivered by VNG on behalf of an area of mutual interest (AMI) group including Lundin and Fortis. Suncor was awarded the license through an independant application.

PL 779 is located in the Central North Sea on the Gudrun Terrace in Block 16/1 (Fig. 1.1) and covers an area of 34 km².

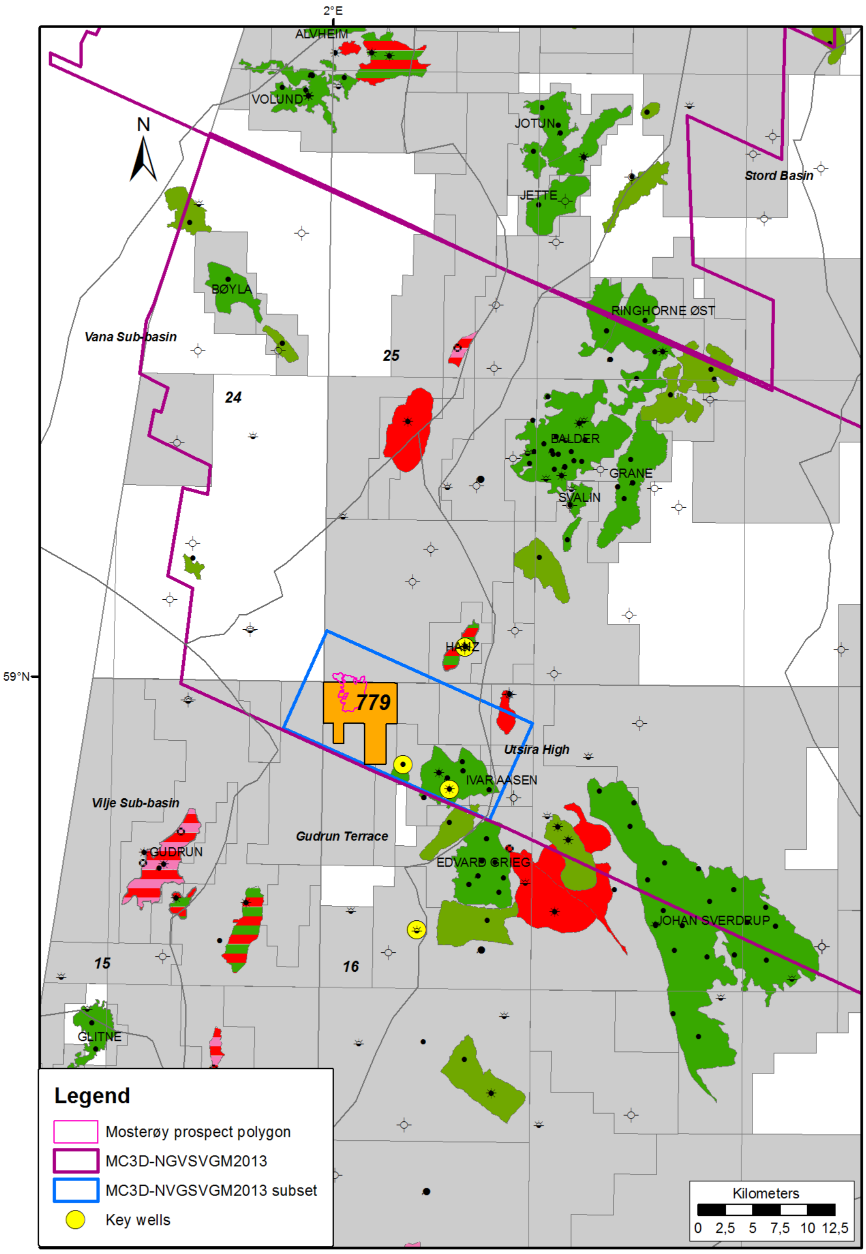


Fig. 1.1 Area map

PL 779 is located on the Gudrun Terrace in between Utsira High to the East and Gudrun Basin to the West. The four key wells are indicated in yellow. The common MC3D-NVGSVGM2013 seismic subset is shown with a blue outline, while the complete seismic survey is partly shown in a magenta outline color.

Work program

The AMI group applied for the available acreage with an Upper Jurassic Prospect as main target. Several other less mature prospects and leads were also identified, but upon award it was decided to focus fully on maturing the main target towards a drilling decision. The proposed AMI APA application work program was accepted and included:

1. Perform relevant geology- and geophysics studies within one year from award
2. Decide to drill an exploration well or to drop the license within one year from award (DOD)

Further work commitments were:

1. Within three years from award make a decision about concretization (BOK)
2. Within five years from award make a decision about continuation (BOV)
3. Within six years from award submit a plan for development (PDO)

Licence meetings

Regular license meetings were held at the VNG Stavanger office with occasional vidoelink to the VNG Oslo office. There were two Management Committe meetings and four Exploration Committee meetings as according to Table 1.1.

Table 1.1 License meetings overview

Date	Management Committee Meeting	Exploration Committee Meeting
March 27th 2015	MC #1	EC #1
April 29th 2015		EC #2
September 3rd 2015		EC #3
September 24th 2015	MC #2	EC #4

Reason for relinquishment

The partnership did not succeed in agreeing on a drill decision for the main prospect Mosterøy. The operator proposed an exploration well, but was not supported by any of the partners. Partner Fortis then proposed a license extension which was supported by Lundin. VNG and Suncor did not support the extension.

The voting rules in the license required at least two companies with at least 60% equity for a decision. The license was therefore relinquished.

2 Database

Seismic database

The licence area is covered by multiple seismic surveys of varying vintage and quality. The operator proposed to use a subset of the latest PGS GeoStreamer MC3D-NVGSVGM2013 survey (now marketed as SVG11) as the common basis for seismic interpretation and analysis. These data are of good quality and covers a sufficient area around the licence acreage. The acquisition of these multiclient data was uncertaken in 2011 by PGS and forms, together with GeoStreamer data to the North (NVG11), a continuous dataset covering the Vana Sub-Basin and Utsira High. The chosen 200 km^2 subset of this merge is based on relevant tie wells and semi-regional data needed to properly describe the prospective areas in PL 779. The outline can be seen in Fig. 1.1. The original data were post stack noise- and frequency conditioned to enhance data quality in the area and depth of interest.

In addition to the SVG11 dataset all partners had access to the PGS regional NNS Mega Survey consisting of vintage 3D seismic data. This is a useful secondary dataset for interpretation surrounding the MC3D-NVGSVGM2013 subset, although the seismic quality is more varying and lacking offset data.

Well database

All relevant regional wells were evaluated for the prospectivity analysis. Table 2.1 lists the released background wells also used in the APA2014 application (VNG Norge AS et al., 2014). Four of the closest wells were seen as especially important. Ichron Limited had performed an extensive biostratigraphic analysis for these, and 71 other wells, as part of their "South Viking Graben and Utsira High Stratigraphic Database" (Ichron Limited, 2014). The four wells were 16/1-5, 16/1-7, 16/1-9 and 25/10-8, and can be seen on the map in Fig. 1.1. The Ichron analysis for these wells was included in the common well database.

The wells were used for studying sandstone provenance, reservoir properties and distribution.

Table 2.1 Common well database

Listing of released wells used in the license. Ichron biostratigraphy was included for the four highlitghted wells.

Well name	Field/Discovery	Spud date	Operator	TD		
				Formation	Age	Depth [m TVD]
15/3-1S	Gudrun	27.11.1974	Elf Petroleum	Hugin Fm.	Middle Jurassic	5 129 (MD)
15/3-3	Gudrun	05.01.1979	Elf Petroleum	Skagerrak Fm.	Triassic	5 112
15/3-7	Gudrun	26.04.2001	Statoil	Sleipner Fm.	Middle Jurassic	4 817
15/3-8	Gudrun	03.11.2005	Statoil	Draupne Fm.	Late Jurassic	4 591
15/3-9	Brynhild	19.05.2010	Statoil	Sleipner Fm.	Middle Jurassic	4 650
16/1-1		26.09.1967	Esso	Hod Fm.	Late Cretaceous	3 177
16/1-2	Ivar Aasen/Draupne	04.07.1976	Esso	Basement	Pre-Devonian	2 894
16/1-3		29.07.1982	Esso	Basement	Pre-Devonian	3 496
16/1-4		17.03.1993	Statoil	Basement	Pre-Devonian	2 010
16/1-5		12.10.1998	Statoil	Basement	Pre-Devonian	2 452
16/1-6S	Verdandi	22.05.2003	Statoil	Ekofisk Fm.	Paleocene	1 909
16/1-7	Ivar Aasen/W.Cable	29.04.2004	Exxon	Skagerrak Fm.	Late Triassic	3 185
16/1-8	Edvard Grieg/Luno	08.09.2007	Lundin	No Fm. defined	Late Triassic	2 200
16/1-8R	Edvard Grieg/Luno	02.10.2009	Lundin	No Fm. defined	Triassic	2 201
16/1-9	Ivar Aasen/Draupne	19.02.2008	Noil Energy	Skagerrak Fm.	Late Triassic	2 536
16/1-10	Edvard Grieg/Luno	13.11.2008	Lundin	No Fm. defined	Early Jurassic	2 151
16/1-11	Ivar Aasen/Draupne	23.02.2010	Det Norske	Skagerrak Fm.	Late Triassic	2 625
16/1-11A	Ivar Aasen/Draupne	26.04.2010	Det Norske	Skagerrak Fm.	Late Triassic	2 528
16/1-12	Edvard Grieg/Luno	29.07.2009	Lundin	Basement	Pre-Devonian	2 055
16/1-13	Edvard Grieg/Luno	21.01.2010	Lundin	Hegre Fm.	Late Triassic	2 301
16/1-14	Apollo	26.09.2010	Lundin	Skagerrak Fm.	Late Triassic	2 550
16/1-15	Tellus	22.01.2011	Lundin	Basement	Pre-Devonian	2 150
16/1-15A	Tellus	06.04.2011	Lundin	Basement	Pre-Devonian	2 011
16/1-16	Asha	23.10.2012	Wintershall	Rotliegend Gp.	Permian	2 721
16/1-16 A	Asha	07.12.2012	Wintershall	Skagerrak Fm.	Late Triassic	2 663
16/2-1	Ragnarrock	11.07.1967	Esso	Basement	Pre-Devonian	1 906
16/2-2		17.09.2001	Statoil	Rødby Fm.	Early Cretaceous	1 855
16/2-3	Ragnarrock	01.08.2007	Statoil	Basement	Pre-Devonian	1 905
16/2-4	Ragnarrock	08.10.2007	Statoil	Basement	Pre-Devonian	2 000
16/2-5	Johan Sverdrup	13.05.2009	Statoil	Basement	Pre-Devonian	2 373
16/2-6	Johan Sverdrup	20.07.2010	Lundin	Zechstein Gp.	Late Permian	2 131
16/2-7	Johan Sverdrup	19.07.2011	Lundin	Rotliegend Gp.	Early Permian	2 500
16/2-7A	Johan Sverdrup	02.09.2011	Lundin	Skagerrak Fm.	Triassic	2 010
16/2-8	Johan Sverdrup	17.07.2011	Statoil	Skagerrak Fm.	Triassic	2 140
16/2-9S	Johan Sverdrup	21.08.2011	Statoil	Basement	Pre-Devonian	2 071
16/2-10	Johan Sverdrup	28.10.2011	Statoil	Skagerrak Fm.	Late Triassic	2 090
16/2-11	Johan Sverdrup	03.02.2012	Lundin	Skagerrak Fm.	Triassic	2 125
16/2-11A	Johan Sverdrup	29.03.2012	Lundin	Skagerrak Fm.	Triassic	2 072
16/3-4	Johan Sverdrup	16.05.2011	Lundin	Basement	Pre-Devonian	2 020
16/3-4A	Johan Sverdrup	28.06.2011	Lundin	Basement	Pre-Devonian	1 959
16/4-5		04.02.2010	Lundin	Basement	Pre-Devonian	2 020
16/5-2S		28.11.2011	Lundin	Skagerrak Fm.	Late Triassic	2 037
24/12-1(R)		07.06.1978	Statoil	Hegre Fm.	Triassic	4 825
25/7-2	"25/7-2"	08.02.1990	Conoco	Sleipner Fm.	Middle Jurassic	4 847
25/10-7S		20.05.1996	Esso	Ekofisk Fm.	Paleocene	2 582
25/10-8	Hanz	17.02.1997	Esso	Rotliegend Gp.	Early Permian	2 653
25/10-8A	Hanz	08.04.1997	Esso	Draupne Fm.	Late Jurassic	2 537
25/10-11S	Earb South	22.02.2011	Marathon	Hugin Fm.	Jurassic	4 560

Studies database

Fault sealing was one of the main challenges for the Mosterøy prospect. The operator proposed to include a fault seal study performed for the inactive PL 500 covering the same area as PL 779 (RDR, 2013). This study analysed the fault seal potential for different depositional models and produced corresponding hydrocarbon column heights. Although this study was not decisive for the final prospect risking, it gave a quick overview of possible outcomes in an early stage of the license work period. The report was prepared by Rock Deformation Research Ltd (RDR) in 2013.

The licencees also agreed to include TGS Facies Map Browser (FMB) to the common studies database to get control over published well information related to play analysis.

3 Review of geological framework

The APA 2014 application was based on an Upper Jurassic play understanding from available well data, structural lineaments and seismic interpretation of key reflectors (VNG Norge AS et al., 2014). The Intra Draupne Formation Mosterøy prospect is an opportunity within this play with a probability for success of 0.22 and mean recoverable volumes of 7.7 x 10^6 Sm^3 o.e. Other prospectivity includes the Sokn prospect in the Middle Jurassic Hugin Formation and/or Upper Triassic Skagerrak Formation. There were two leads identified; Åmøy lead in Early Cretaceous Ty Formation sandstones and Klosterøy lead in Middle to Late Eocene Grid Formation (Fig. 3.1).

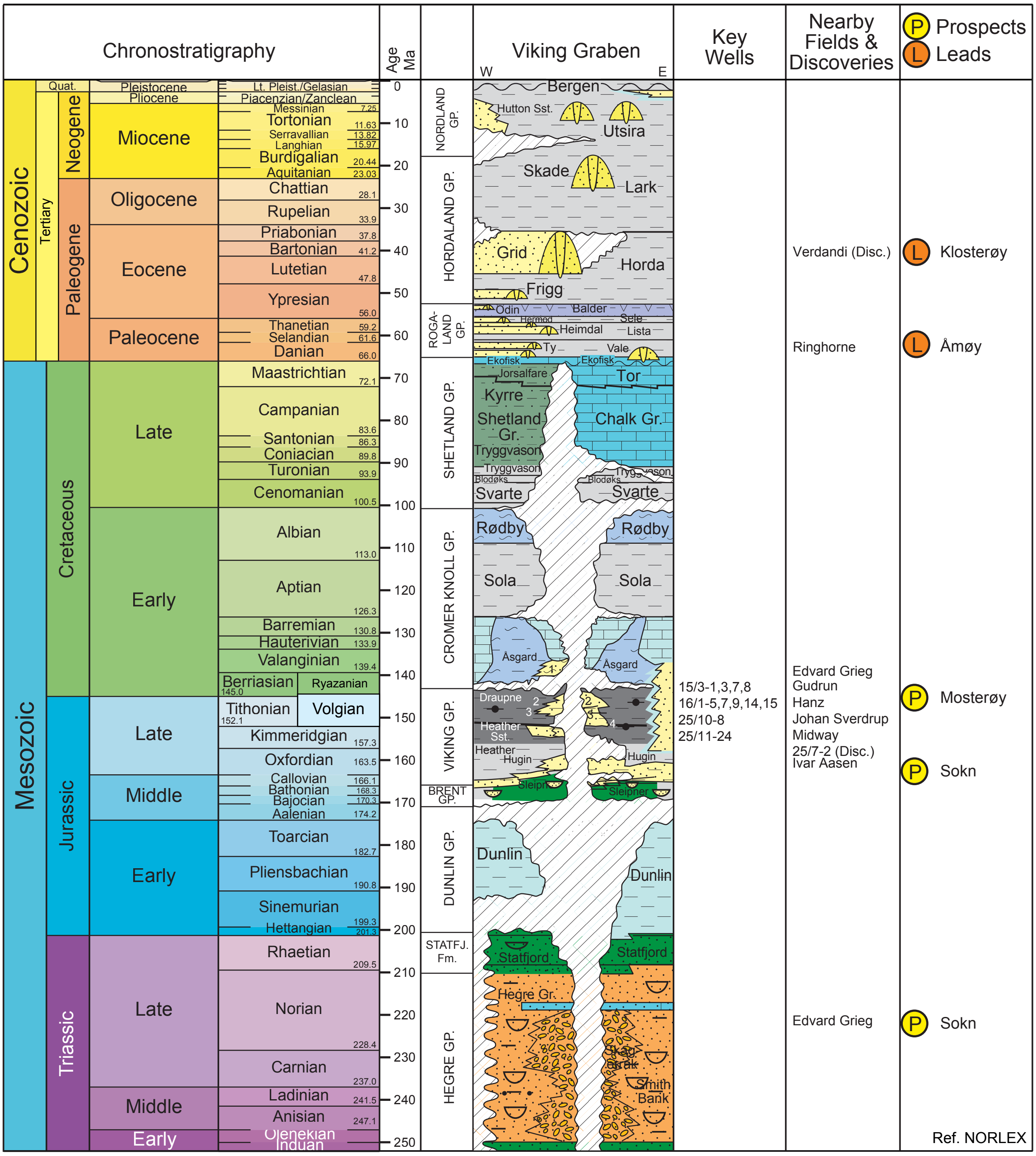


Fig. 3.1 Stratigraphic chart

Stratigraphic position of the Mosterøy and Sokn prospects, and the Åmøy and Klosterøy leads. Modified from NORLEX. From VNG Norge AS et al., 2014.

The technical work after award was concentrated towards maturing the Mosterøy prospect to a drilling candidate. The licence prioritised selected prospect volume- and risk factors in the compact G&G work program time-line. This was possible because of the good technical input from Fortis in the application phase that created a framework for further maturation of the prospect. The operator identified technical activities related to two specific areas: seal/retention and effective reservoir. The seal/retention work can be found in Section 4 Prospect update, whilst the reservoir presence was adressed by a more regional approach to understand the depositional system as explained below.

Upper Jurassic depositional system

The seismic data was used to look for alternative Upper Jurassic depositional routes in to the PL 779 area. If found, they could question the expected northeast to southwest sediment transport direction, and in some scenarios reduce the fault seal intergrity for Mosterøy. Detailed seismic interpretation of the reservoir interval was performed, and different seismic attribute analysis supported the main north-south depositional trend. No indications of sands deposited directly from the East across the main north-south fault were observed. A red-green-blue (RGB) frequency blend anomaly was found coinciding with the defined prospect outline, but the understanding and confidence of this is too immature to affect the prospect properties or risks directly (Fig. 3.2). Additional seismic interpretation to the North of the prospect could help understand the delimitation towards PL 626.

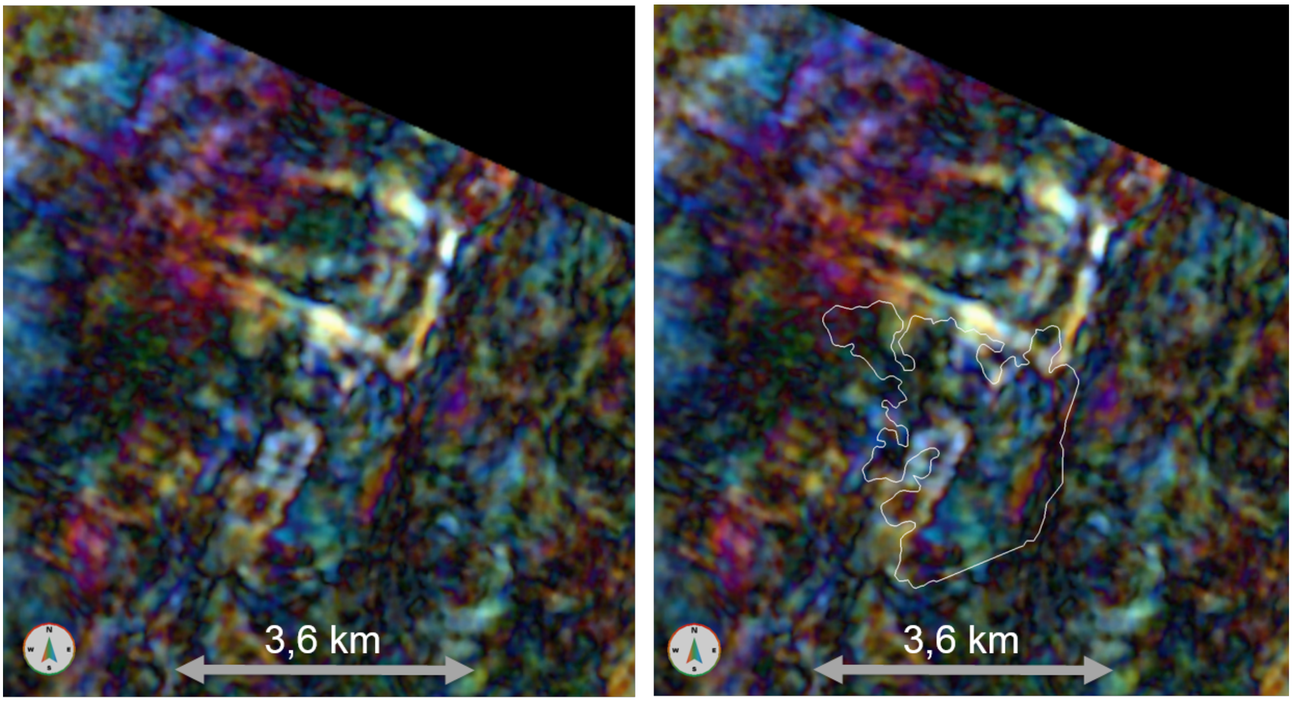


Fig. 3.2 GeoTeric RGB blend

Three frequency bands were combined in this red-green-blue (RGB) frequency decomposition cube. The frequency bands were selected to cover the bandwidth of the data to help reveal the interplay between the different bands.
In this case the RGB cube supports the existing prospect outline (white polygon) as defined with a reservoir thickness cutoff. Although frequencies also themselves represent thicknesses, the RGB method shows that there is a vertical- and areal delimitated body here that is different from the background stratigraphy independent of how the seismic interpretation is done.
The frequency bands selected for this exercise had peak frequencies of 15 Hz, 19 Hz and 26 Hz.
The time slice from the RGB blend is taken at 2800 ms TWT.

Sleipner- and Hugin Formation deposits across the Gudrun terrace suggest the area was a relatively flat, stable platform towards the end of the Middle Jurassic. The rapid drowning of this relatively flat area at the onset of rifting ensured that most of the Gudrun Terrace area was far from any potential sediment sources from this phase onwards. Heather Formation shales with no significant sand content, are therefore found over a large area with the exception of the margin of the Utsira High. The Heather Formation is entirely absent from individual fault blocks, mostly towards the centre of the terrace and possible due to the presence of local highs before rifting began. The main faults follow a north-northeast to south-southwest trend such that the highs and lows of rotated fault blocks provide barriers between the Mosterøy area and the Utsira High to the East. By Kimmeridgian age the sediment transport systems had adapted to the rifted topography and turbidites were directed by the increasing topography, following the north-northeast to south-southwest trend of the faulting. The PL 779 area is interpreted to represent an active (syn-tectonic) accomodation space on one of the sidearms to the Gudrun Terrace feeder turbidite fairways (Fig. 3.3). Remains after these fairway systems can be interpreted from Viking Group isochrones where elongated north-south aligned features are observed. Fig. 3.4 shows how major faults on the Base Triassic level is thought to take part in controlling the Jurassic sand deposition fairways.

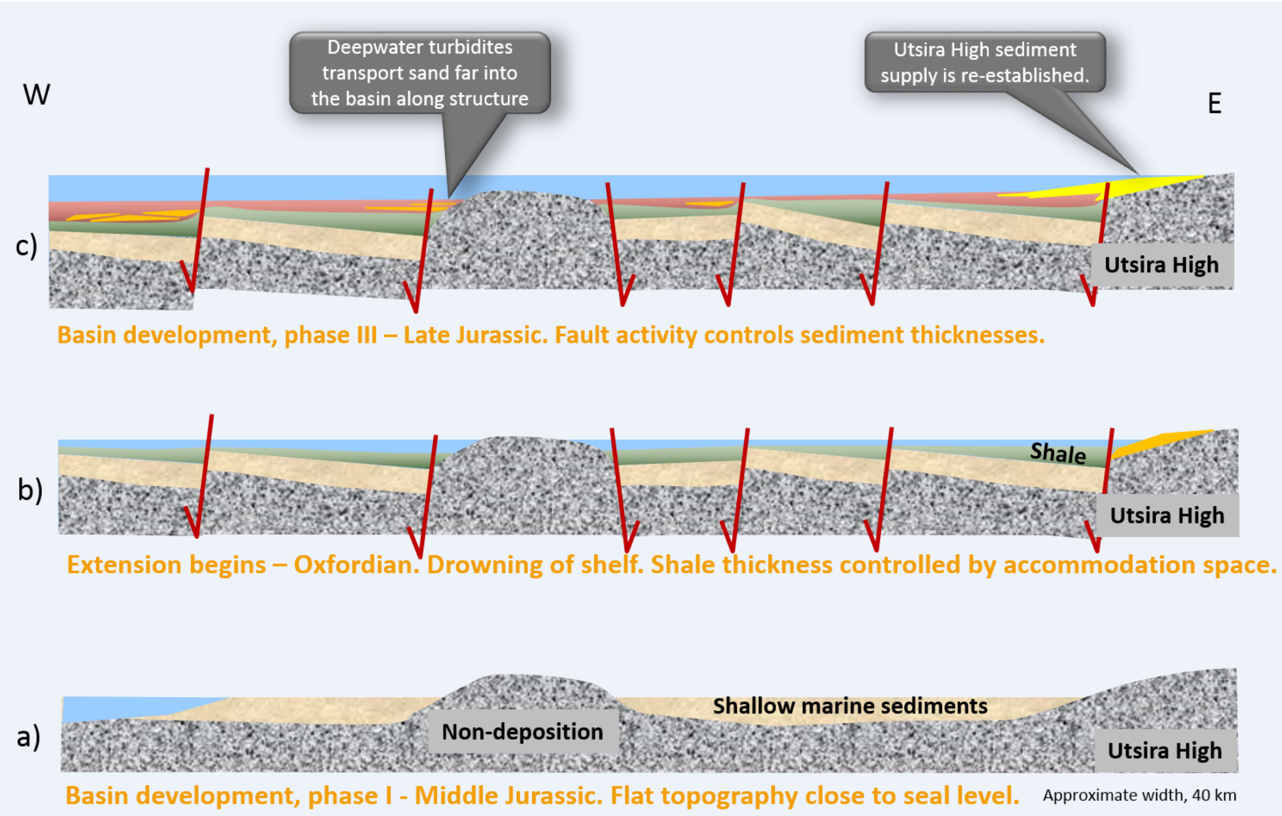


Fig. 3.3 Semi-regional depositional model

a) Shallow marine Middle Jurassic sediments are found deposited westwards from the Utsira High pre-/during the start of the rifting.

b) As extension activity increased, topography on the seabed controlled accomodation space. Observed as varying thicknesses of Heather-, Hugin- and Sleipner Formation in wells depending on position relative to structural elements.

c) Upper Jurassic Intra Draupne Formation sandstone turbidites enter the system and settles where accomodation space is available. The Mosterøy prospect is interpreted to hold deepwater turbidites derived from the larger East to West fairway contributing to the Gudrun Field.

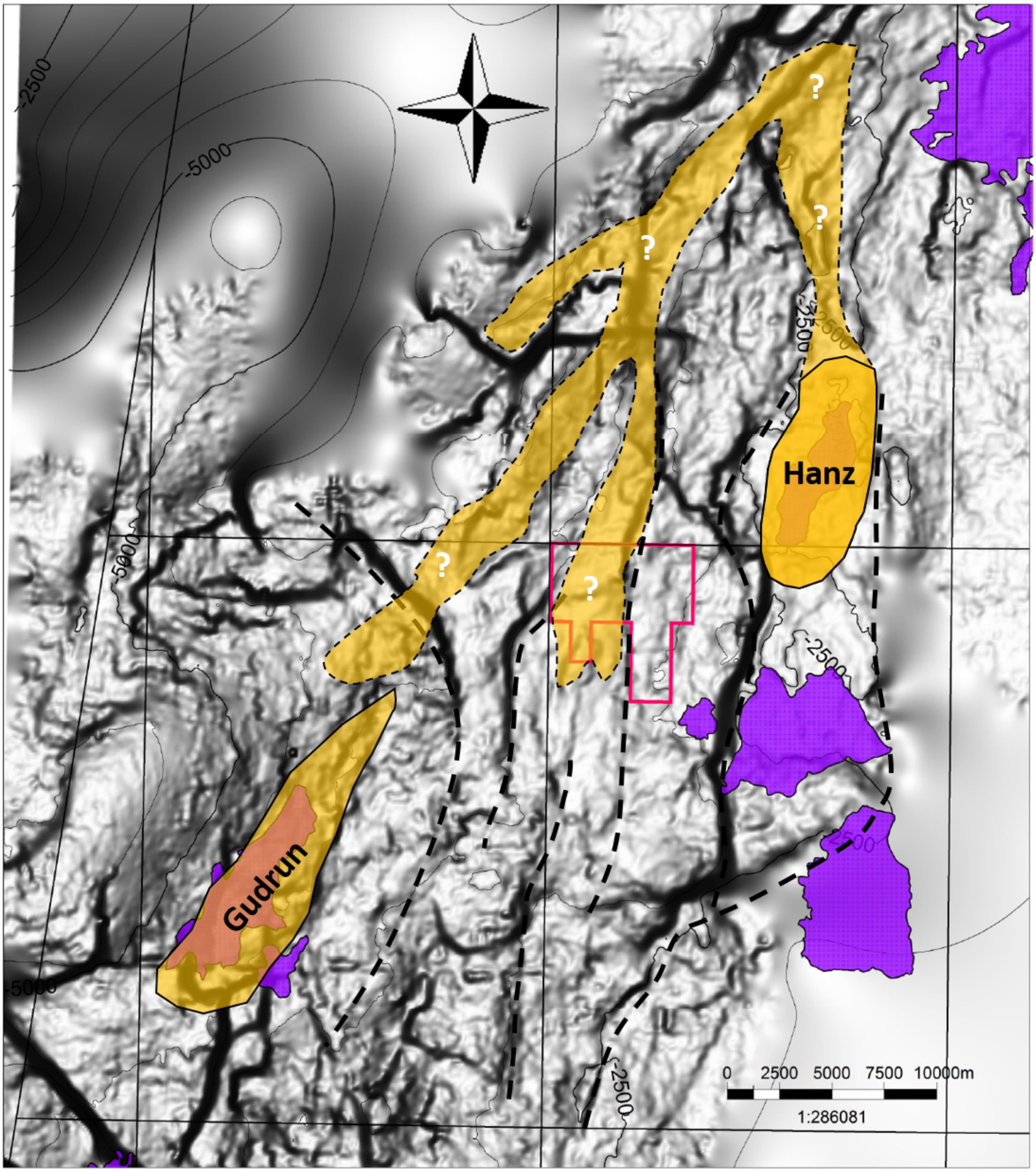


Fig. 3.4 Sand deposition model

The background black/white map shows an edge detection attribute applied to a Base Triassic regional surface. The existing hydrocarbon fields are added as purple polygons. In the Gudrun- and Hanz Discoveries there are proven Intra Draupne Formation reservoirs. The turbiditic composition of the Intra Draupne Formation sandstone in the Gudrun Field suggest that they have been transported over long distances from the source area on the Utsira High to the East.
A possible sand fairway model with a dashed outline has been added in this figure to explain how Intra Draupne Formation sandstone can be deposited in the PL 779 area.

This depositional model is supported by thickness observations in wells where the position of the well relative to fault block tilt, and distance from sediment source area, can reasonably well predict the thickness for the Upper Jurassic formations. Eastwards tilting fault blocks close to the Utsira High for example, contain more (proximal) sands than the next fault block to the West. This indicates that sand input directly from East to West has been hindered by rotated fault block topography at the time of deposition. Any Upper Jurassic Intra Draupne Formation sandstones on the Gudrun Terrace were therefore more likely (distal) sands sourced from the Northeast. As seen in Section 4 Prospect update, the reservoir study actually reduced the probability for reservoir presence and quality from 0.6 to 0.5 because of the geological model confidence and lack of direct sand indicators, but increased the probability of finding a viable trap due to reduced risk of thief sands from the East.

Velocity model

A new semi-regional velocity model was constructed based on available well data. This new model was needed to verify contacts and spillpoints in a part of the stratigraphy affected by high velocity intervals. In short, the methodology was designed to optimise fit to the available well data whilst minimising extrapolation to avoid creating artificial structure in depth. Velocity contrasts from wells were used to create velocity zones. A single constant velocity (or a constantly increasing velocity with depth) was then estimated for each zone, based on all of the well data. Even with this simple velocity model it proved possible to match most of the wells to within a few tens of metres. Local corrections around the wells were then applied, quality checked and smoothed. This velocity model was then used to depth convert the time interpretations for generating volume input to GeoX.

The key factor in the velocity model was the chalk layer that due to its high velocity greatly influenced how the deeper stratigraphy was positioned in depth.

New wells

There were no new 2015 well results relevant for the PL 779 evaluation.

4 Prospect update

Seismic interpretation

The seismic data was, as explained in Section 2 Database, noise conditioned and frequency enhanced to better visualize the reservoir interval. This dataset was used to adjust important interpretation in parts of the prospect, in addition to tie surfaces from the nearest wells. The adjusted interpretations were also used for attribute analysis and to have the best detailed overview of thicknesses, spill points and fault planes.

Mosterøy

The license has done selected work to investigate remaining uncertainties for the Mosterøy prospect, especially involving hydrocarbon phase, hydrocarbon-water contact distribution and seal/retention risk. The main geological model for the Mosterøy prospect is unchanged since license award. The G&G work program has confirmed some of the existing prospect risks and modified others. The volumetric container is the same with the exception of a more detailed seismic interpretation and a refined velocity model. To reflect the uncertainty in hydrocarbon phase a gas cap is introduced in the resource calculation.

Volumetric input

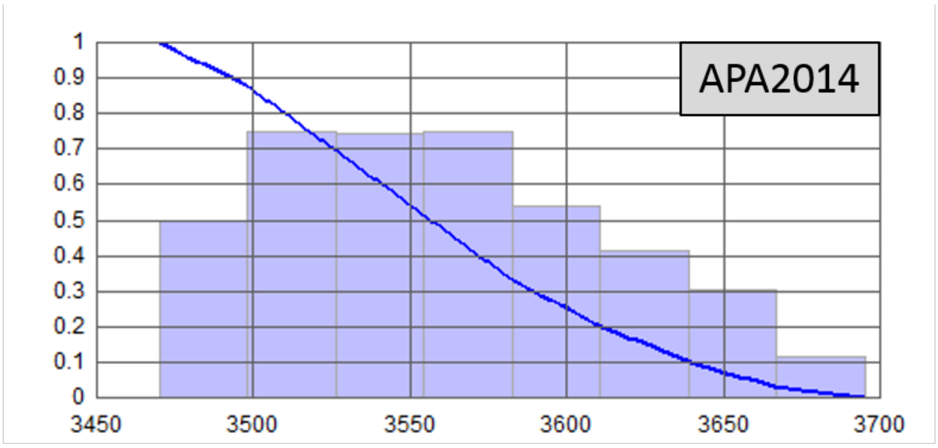
Fluid phase

The fluid phase setup was changed from a 100 % oil case to a combined gas- and oil case. The PL 779 area is located at the start of the Draupne Formation oil window, but a free gas cannot be ruled out due to efficient migration as observed in nearby fields and discoveries. Gas is present mostly as gas caps on top of a dominant oil phase in the shallower eastern field (Ivar Aasen), while the western Gudrun Field has a higher gas to oil ratio. The Sigrun Field lies on the same structural terrace as Mosterøy and also has an oil and gas accumulation.

The gas- to oil leg ratio found on Ivar Aasen- and Edvard Grieg Fields was used to guide the equivalent ratio in Mosterøy. A gas-oil contact resulting in 15 % in-place gas volume (of total in-place oil equivalents) at standard conditions was chosen to account for the scenario including free gas in the mean volumetric case. Gas properties were taken from Well 15/3-4 (Sigrun discovery).

Hydrocarbon-water contact

The hydrocarbon contacts have been updated with the gas oil contact and intermediate spill point depths. The hydrocarbon-water contact distribution trend, i.e. a declining probability for higher columns against the fault, follows the same principle as described in the APA2014 AMI application (VNG AS et al., 2014). During the re-evaluation a more refined distribution was made to highlight the spill points identified in the northern part of the prospect. These are possible leakage points for hydrocarbons as the gross reservoir thickness is >50 m and connected to possible Intra Draupne Formation sandstones extending northwards. But, there are still possible barriers to the north of these thief-sands, so the two highlighted spillpoints do not represent the end of the contact distribution (Fig. 4.1). Fig. 4.2 illustrates where the minimum, mean and maximum hydrocarbon-water contacts are on the prospect structure. Fig. 4.3 is illustrating the same hydrocarbon-water contacts in 2D map view to give a better overview of where they are located with regards to reservoir isochore and the spillpoints used in Fig. 4.1.



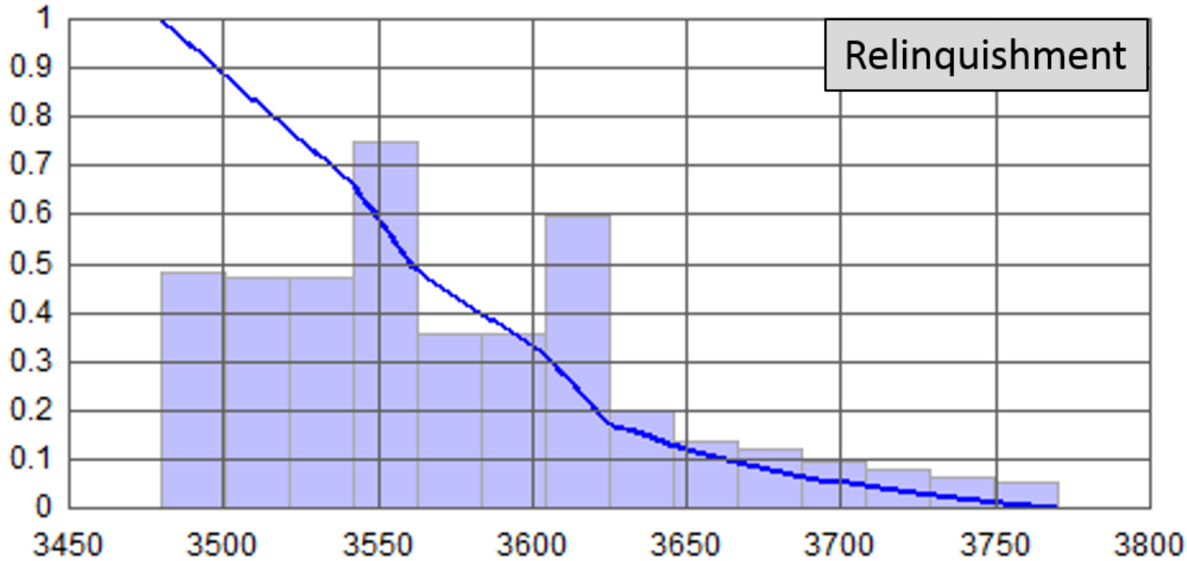


Fig. 4.1 Hydrocarbon-water contact distribution

Upper: Hydrocarbon-water distribution from APA2014 AMI application

Lower: Hydrocarbon-water distribution at relinquishment time. The two peaks in the distribution represent spill points as illustrated on Fig. 4.3.

The risking parameters from Table 4.2 reflects the associated risks for a volume with a column greater than the minimum column of 3480 m (80 m column from the structural crest).

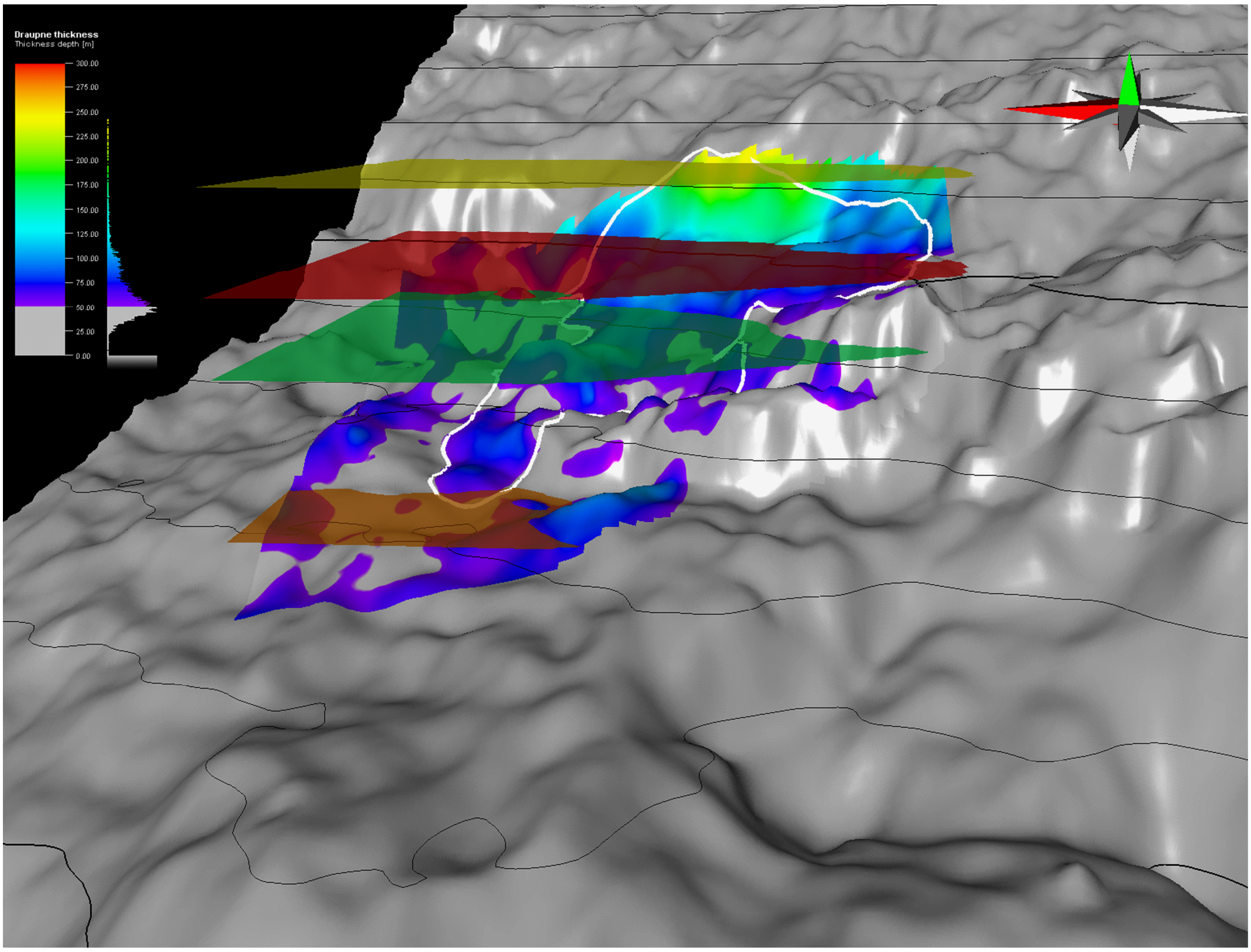


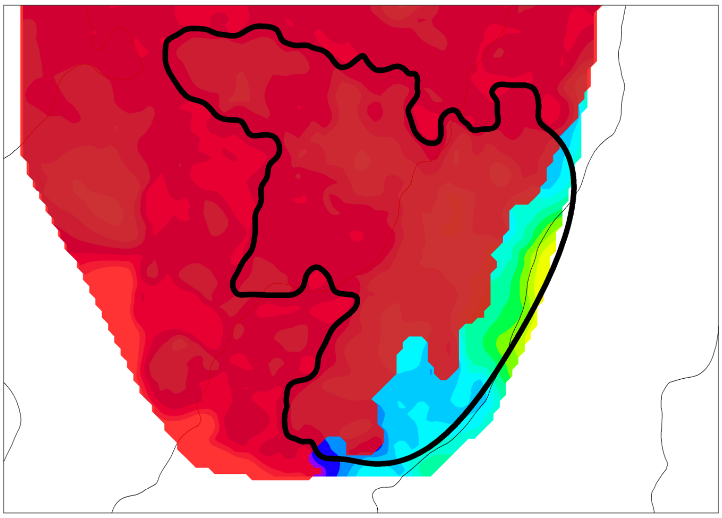
Fig. 4.2 Hydrocarbon-water contacts

This map in 3D view shows the Intra Draupne Formation isochore map draped on the top reservoir surface (Base Cretaceous reflector). The color legend and associated histogram reflects the thicknesses.

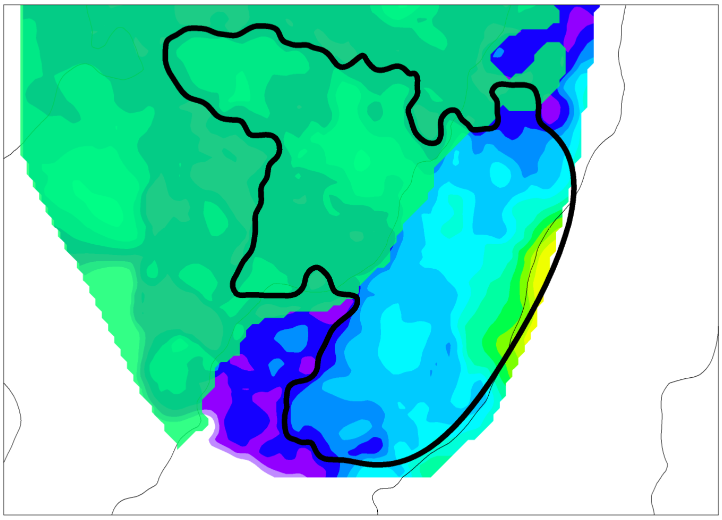
The prospect polygon is in white.

In addition four surfaces are included to represent: yellow: crest of structure, red: minimum-, green: mean- and orange: maximum hydrocarbon-water contact.

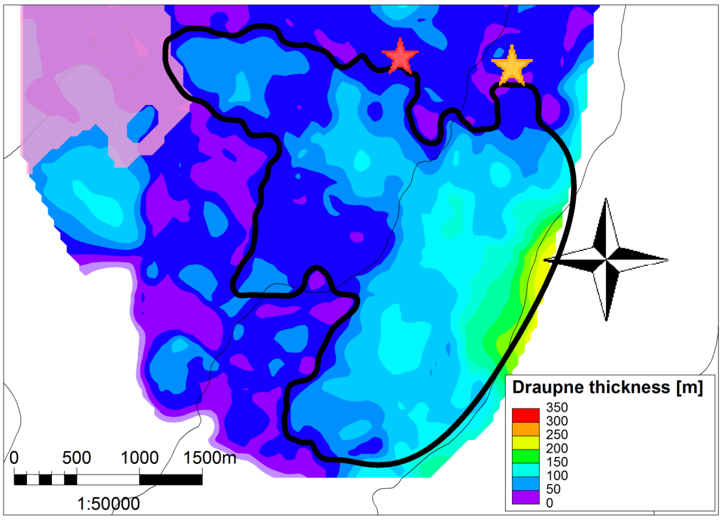
The red part of the star points towards North.



a) Minimum hydrocarbon-water contact



b) Mean hydrocarbon-water contact



c) Maximum hydrocarbon-water contact

Fig. 4.3 Individual hydrocarbon-water contacts

The minimum, mean and maximum hydrocarbon-water contacts are overlayed on the same Intra Draupne Formation isochore map as seen in Fig. 4.2.

The prospect polygon is in black.

The maps clearly show how the thickest part of the prospect is located in the shallower eastern part.

The contact distribution was also slightly altered compared to the APA2014 evaluation to account for the gas cap. A flat gas-oil contact distribution was chosen to reflect the high uncertainty based on the observed gas-oil columns in nearby discoveries and fields (Fig. 4.4).

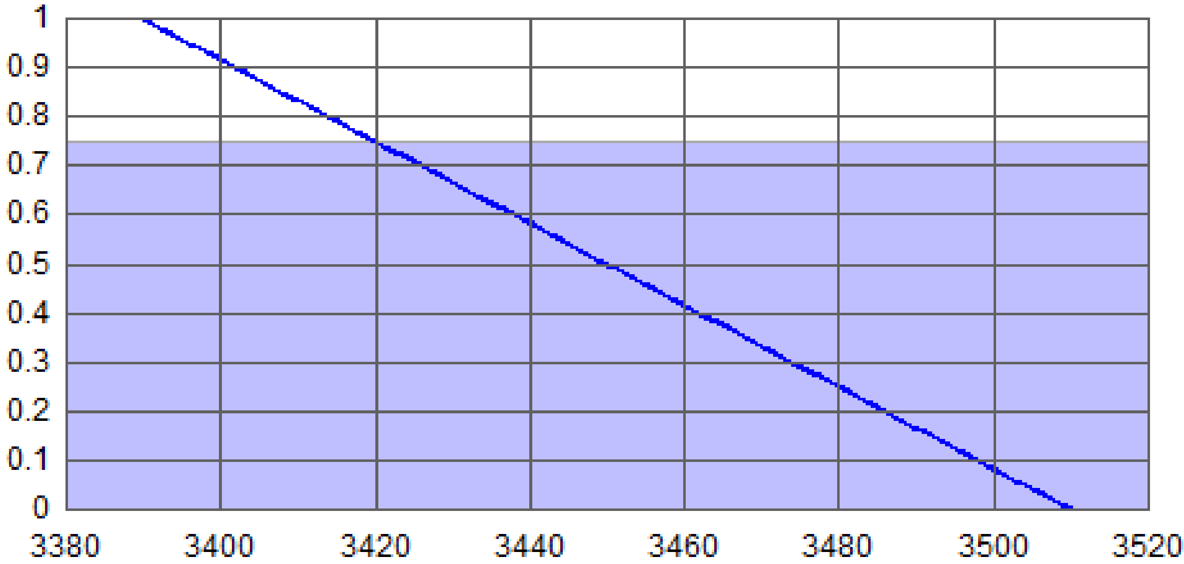


Fig. 4.4 Gas-oil contact distribution
The gas-oil contact distribution shows a uniform probability for a column 20 to 120 m high.

Risk Assessment

The play level risks did not change (Table 4.1). The fault seal work (retention risk factor) increased the probability for discovery by 50 % from 0.22 to 0.32.

Table 4.1 Risk assessment Mosterøy - comparison application and relinquishment values

Risk factor	APA 2014 application	Relinquishment
Regional Seal (play level)	1	1
Reservoir Facies (play level)	1	1
Source Rock Facies (play level)	1	1
Reservoir	0.6	0.5
Trap	0.9	0.9
Retention	0.4	0.7
Charge	1	1
Prospect probability	**0.22**	**0.32**

<u>Seal/Retention</u>

The major prospect risk, as identified in the APA work, was the sealing capabilities of the Mosterøy main bounding north-south fault. A fault seal study had already been undertaken by the previous license in this area (PL 500), and this report (RDR, 2013) was purchased and included in the PL 779 common study database. The study conclusions were in a large degree directly dependent on the input models and assumptions. Different combinations of lithologies, post-rift and syn-rift deposition patterns, intra-reservoir clay position and footwall- and/or hanging wall clay smear factor were included in their analysis.

The evaluation was very comprehensive and thorough. The challenge was to choose which of the study input models that best represented the interpretation and geological model. Fig. 4.5 shows two of the input models used in the RDR report.

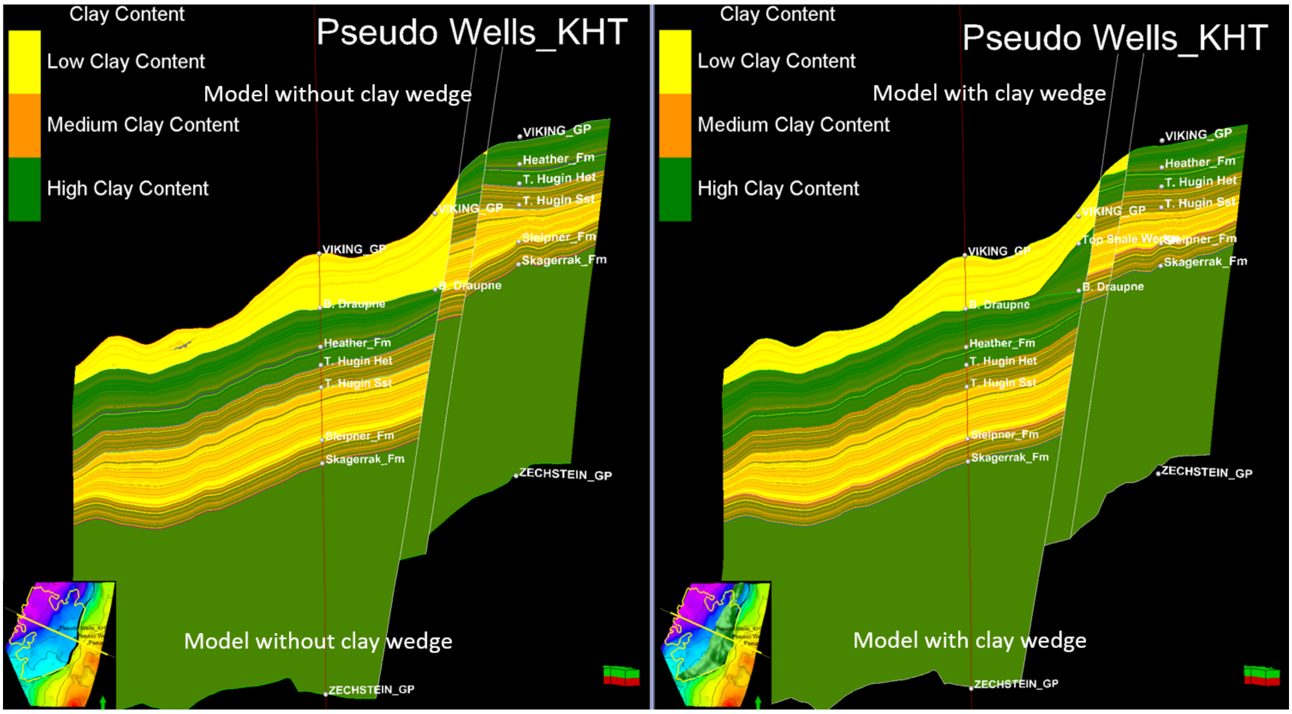


Fig. 4.5 Base case fault seal model from APA2014 application (VNG et al., 2014)
Left: Model without clay wedge. Right: Model with clay wedge. From Fortis RDR model in Petrel. Model from BCU to Top Skagerrak Fm. No clay smear from foot-wall. Yellow: high N/G sandstones, orange: medium/low N/G (heterogenous) sandstones/ shales, green: shales.

The operator proposed an alternative conceptual model for fault seal, taking into account the syn-tectonic depositional model for the Intra Draupne Formation sandstones. This model suggests much more favourable conditions for sealing the Mosterøy prospect to the East compared with the original RDR study input models. This new model allows for a better sealing across the fault plane by limiting juxtaposition of Intra Draupne Formation sandstones against Middle Jurassic Hugin- and/or Sleipner Formation sandstones. Fig. 4.6 describes the turbidite deposition model based on expected paleogeography and sediment composition and -energy. The seismic support for internal geometries at this scale is limited as the acoustic properties between sand and shale at this level are very similar.

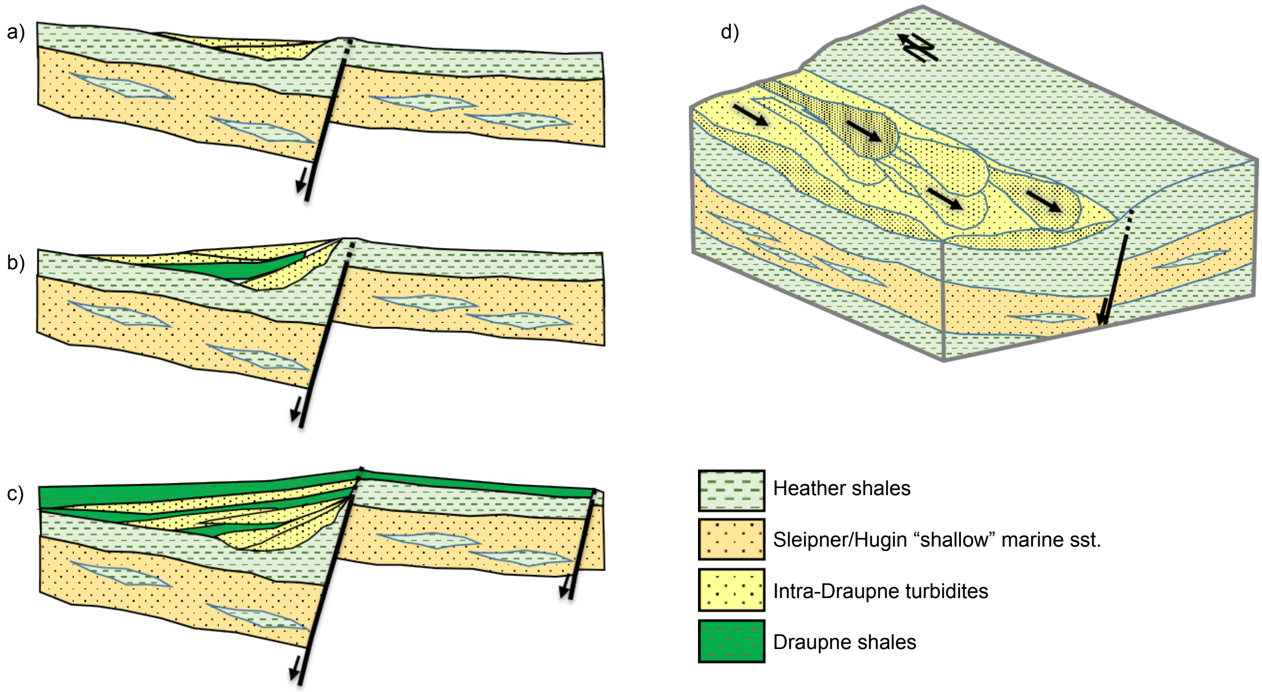


Fig. 4.6 Deposition of Intra Draupne Formation sandstones
a) Movement on the fault started at the onset of Heather Formation shale deposition.
The fault probably did not reach the surface but created a gentle and smooth accumulation space for turbiditic currents prograding in from the North/North-northeast. No significant paleo-topography present or required.
b) Fault movement continues during Intra Draupne Formation deposition. In combination with the compaction of the Heather Formation shales below the oldest sandstones, it generates further depositional space. The turbiditic sandstones are intercalated with Draupne Formation shales. The fault movement probably leaves a significant volume of Heather Formation shales between the prospective sands and it's foot-wall.
c) Fault movement continues and a younger fault initiates up-dip, creating accumulation space for Draupne Formation shales on the foot-wall of the prospect. The oldest Intra Draupne Formation sand packages got tilted due to the ongoing fault movement – possibly causing any dip-shaped reflections at the thickest part of the prospective Upper Jurassic wedge.

The Lower Cretaceous interval was investigated in the nearest wells to learn if it could have had any impact on top seal risk. The main analogue well, 16/1-7 (West Cable), did not show any evidence of sandstones that could be of risk for the main prospect.

Combined, this work led to an increased probability for seal/retention in the Mosterøy prospect compared to the APA 2014 evaluation.

<u>Seismic data analysis</u>

A relative inversion feasibility study was performed to look for amplitude anomalies related to lithology and/or fluid effects. The main conclusions from this study are summarized below:

1. Data quality were sufficient to expect a lithology- or fluid anomaly given good impedance contrasts
2. Nearby wells show that little/no seismic response is expected between the interface of Intra Draupne Formation sandstones and surrounding shales
3. The Gudrun Field and Well 25/10-8 (Hanz) are both Intra Draupne Formation discoveries lacking geophysical response for either lithology or fluids on the seismic. The weak impedance contrast between the Draupne Formation and the Heather Formation interval generated from wells with Draupne Formation explains why it is challenging to detect Draupne Formation sandstone in the seismic domain.

Seismic data analysis results were therefore not used to modify the prospect probability.

Fortis also contributed with an AVO analysis on their own pre-stack cleaned version of the seismic data where they indicated a potential class 3 AVO associated within parts of the prospect.

Volume output
The updated volumes (Table 4.2) are very comparable to the APA 2014 volumes (Table 4.3). The main difference is a shift from oil to gas in the P90 in-place volumes due to the modelled gas cap.

Table 4.2 NPD Table 5 Prospect data - Updated numbers

This table shows the updated Mosterøy prospect numbers.

Table 5. Prospect data (Enclose map)

Block	16/1	Prospect name	Mosterøy	Discovery/Prosp/Lead	Prospect	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:	Oil	Reported by company	VNG Norge AS	Reference document	PL 779 Relinquishment Report			Assessment year	2015
This is case no:	1 of 1	Structural element	Gudrun Terrace	Type of trap	Combined structural/stratigraphic	Water depth [m MSL] (>0)	114	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 Sm3] (>0.00)	4.94	16.00	16.60	28.90				
	Gas [10^9 Sm^3] (>0.00)					1.24	2.80	3.15	5.26
Recoverable resources	Oil [10^6 Sm3] (>0.00)	2.23	6.08	6.91	12.20				
	Gas [10^9 Sm^3] (>0.00)					0.58	1.15	1.53	2.62
Reservoir Chrono (from)	Oxfordian	Reservoir Litho (from)	Intra Draupne Formation	Source rock, chrono primary	Ryazanian	Source rock, litho primary	Draupne Formation	Seal, Chrono	Upper Jurassic/Lower Cretaceous
Reservoir Chrono (to)	Ryazanian	Reservoir Litho (to)	Intra Draupne Formation	Source rock, chrono secondary	Oxfordian	Source rock, litho secondary	Heather Formation	Seal, Litho	Draupne Fm./Cromer Knoll Gp.
Probability [fraction]									
Technical (oil + gas + oil & gas case) (0.00-1.00)	0.32	Oil case (0.00-1.00)	0.00	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	0.32		
Reservoir (P1) (0.00-1.00)	0.50	Trap (P2) (0.00-1.00)	0.90	Charge (P3) (0.00-1.00)	1.00	Retention (P4) (0.00-1.00)	0.70		
Parametres:	Low (P90)	Base	High (P10)						
Depth to top of prospect [m MSL] (> 0)	3360	3360	3360	40m deeper compared to APA numbers					
Area of closure [km^2] (> 0.0)	0.9	2.7	4.3	*Area of closure from P90, mean and P10 HCW contacts*		*These shallower contacts (compared to the APA assessment) were used to get a smaller P100 recoverable volume.*			
Reservoir thickness [m] (> 0)	50		170	*Gross reservoir thickness based on minimum of 50m (cutoff) and calculated maximum of 170m.*					
HC column in prospect [m] (> 0)	138	215	303						
Gross rock vol. [10^9 m^3] (> 0.000)	0.250	0.290	0.340	*Gross rock volume at mean HCW contact.*					
Net / Gross [fraction] (0.00-1.00)	0.50	0.60	0.70						
Porosity [fraction] (0.00-1.00)	0.21	0.22	0.24						
Permeability [mD] (> 0.0)	10	100	1000	*Based on analogue wells*					
Water saturation [fraction] (0.00-1.00)	0.20	0.30	0.40						
Bg [Rm^3/Sm^3] (< 1.0000)	0.0033	0.0036	0.0040						
1/Bo [Sm^3/Rm^3] (< 1.0000)	0.65	0.68	0.71						
GOR, free gas [Sm^3/Sm^3] (> 0)	443	648	1168						
GOR, oil [Sm^3/Sm^3] (> 0)	116	145	177						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.30	0.40	0.50						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.30	0.40	0.50						
Recov. factor, gas main phase [fraction] (0.00-1.00)	0.60	0.70	0.80						
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)	0.55	0.65	0.75	For NPD use:					
Temperature, top res. [°C] (>0)	125			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)	503			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 4.3 NPD Table 5 Prospect data - APA 2014 version

This table lists the original Mosterøy prospect numbers from the APA 2014 AMI application submitted by VNG, Lundin and Fortis.

Table 5. Prospect data (Enclose map)

Block	16/1	Prospect name	Mosterøy	Discovery/Prosp/Lead	Prospect	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:	Oil	Reported by company	VNG Norge AS	Reference document				Assessment year	2014
This is case no:	1 of 1	Structural element	Gudrun Terrace	Type of trap	Combined structural/stratigraphic	Water depth [m MSL] (>0)	114	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 Sm3] (>0.00)	9.20	13.80	17.00	25.70				
	Gas [10^9 Sm^3] (>0.00)					1.27	1.92	2.48	3.87
Recoverable resources	Oil [10^6 Sm3] (>0.00)	3.39	5.26	6.72	10.60				
	Gas [10^9 Sm^3] (>0.00)					0.47	0.73	0.98	1.60
Reservoir Chrono (from)	Oxfordian	Reservoir Litho (from)	Draupne Formation	Source rock, chrono primary	Ryazanian	Source rock, litho primary	Draupne Formation	Seal, Chrono	Upper Jurassic/Lower Cretaceous
Reservoir Chrono (to)	Ryazanian	Reservoir Litho (to)	Draupne Formation	Source rock, chrono secondary	Oxfordian	Source rock, litho secondary	Heather Formation	Seal, Litho	Draupne Fm./Cromer Knoll Gp.
Probability [fraction]									
Technical (oil + gas + oil & gas case) (0.00-1.00)	0.22	Oil case (0.00-1.00)	0.22	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	0.00		
Reservoir (P1) (0.00-1.00)	0.60	Trap (P2) (0.00-1.00)	0.90	Charge (P3) (0.00-1.00)	1.00	Retention (P4) (0.00-1.00)	0.40		
Parametres:	Low (P90)	Base	High (P10)						
Depth to top of prospect [m MSL] (> 0)	3320	3320	3320						
Area of closure [km^2] (> 0.0)	3.1	3.8	5.4	*Area of closure from P90, mean and P10 HCW contacts*					
Reservoir thickness [m] (> 0)	40		170	*Reservoir thickness based on minimum of 40m and calculated maximum of 170m.*					
HC column in prospect [m] (> 0)	173	242	320						
Gross rock vol. [10^9 m^3] (> 0.000)	0.203	0.290	0.377	*Gross rock volume at mean HCW contact.*					
Net / Gross [fraction] (0.00-1.00)	0.50	0.60	0.70						
Porosity [fraction] (0.00-1.00)	0.21	0.22	0.24						
Permeability [mD] (> 0.0)	10	100	1000	*Based on analogue wells*					
Water saturation [fraction] (0.00-1.00)	0.20	0.30	0.40						
Bg [Rm^3/Sm^3] (< 1.0000)									
1/Bo [Sm^3/Rm^3] (< 1.0000)	0.65	0.68	0.71						
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)	116	145	177						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.30	0.40	0.50						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.30	0.40	0.50						
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)	125			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)	503			Dato:	NPD will insert value	Registrert - Dato:	NPD will insert value	Kart dato	NPD will insert value
Cut off criteria for N/G calculation	>40m reservoir isopach							Kart nr	NPD will insert value

5 Technical evaluations

A full project evaluation was performed to assess the technical and economical aspects of the Mosterøy prospect. The base case for the partner version of this evaluation was the mean untruncated oil volumes (Table 4.2). The gas cap was treated as an upside sensitivity.

The exploration plan program consisted of one exploration well, followed by an appraisal well a year after with a drill stem production test (DST) given positive results from the initial well. This strategy ensured a simple first exploration well, but with no flow test to determine reservoir- and fluid characterization in the first wellbore. A second well would in any case be needed to appraise the reservoir, and to establish a better control of fluid contact(s). This strategy would allow the project to save DST planning- and preparation costs for the first well.

Field development

The field development solution is the same as presented in the AMI APA 2014 application (VNG et al., 2014), and illustrated in Fig. 5.1.

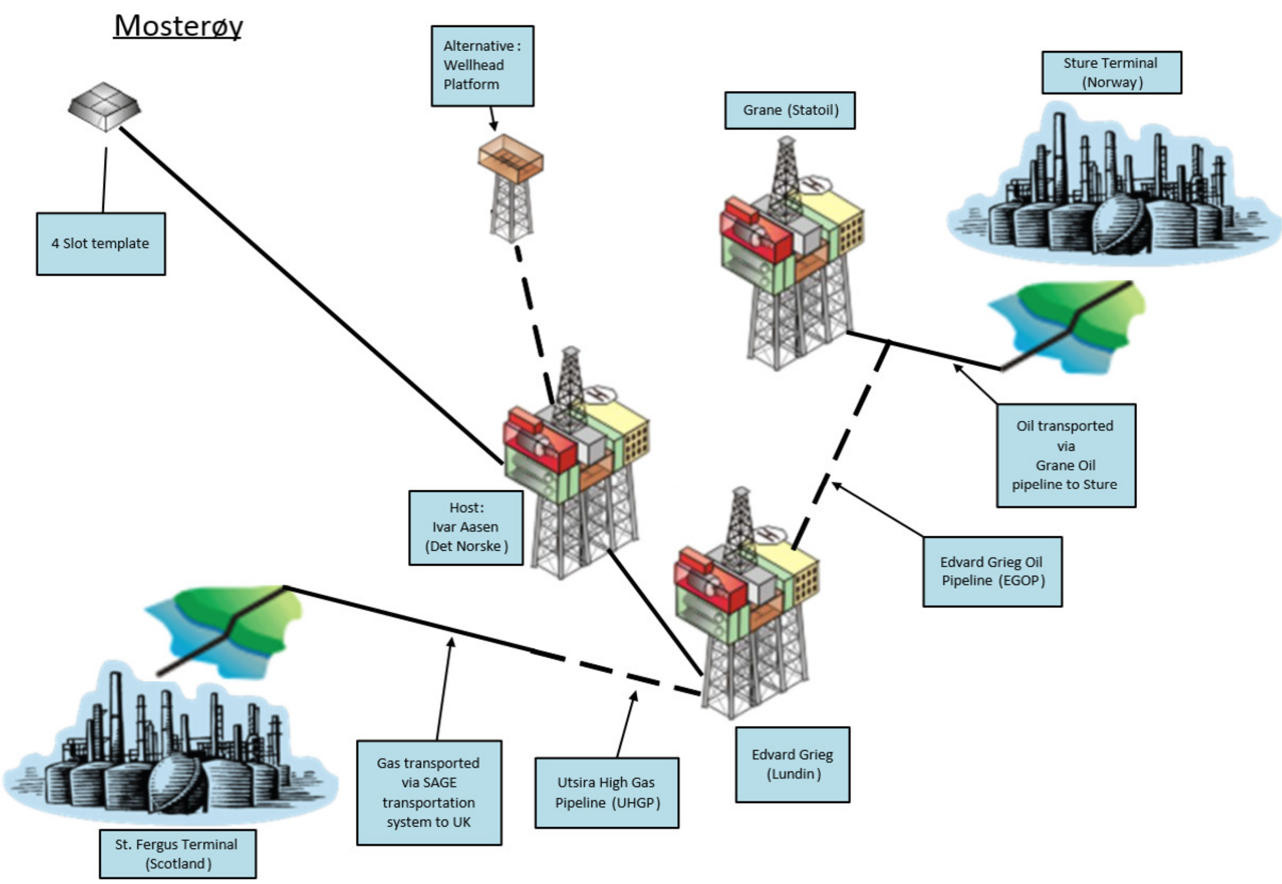


Fig. 5.1 Field development solution
See VNG et al., 2014 for description of development solution.

There are several uncertainties identified with the development solution, among those the most important being:

- possible production constraints on Ivar Aasen and Edvard Grieg
- oil and gas export capacity
- availability of infrastructure for the entire economical field life

The potential upsides to the base case evaluation include:

- reduction in field development costs
- development of Mosterøy gas cap (gas blow-down)
- direct tie-in to Edvard Grieg field

Health, safety and environment (HSE)

No HSE concerns have been identified for the Mosterøy prospect at this time. The PL 779 licence is located in a well established area with no particular vulnerable resources in the vicinity. There are also no seasonal restrictions related to drilling activities. The reservoir conditions do not classify the Mosterøy prospect as high pressure high temperature (HPHT).

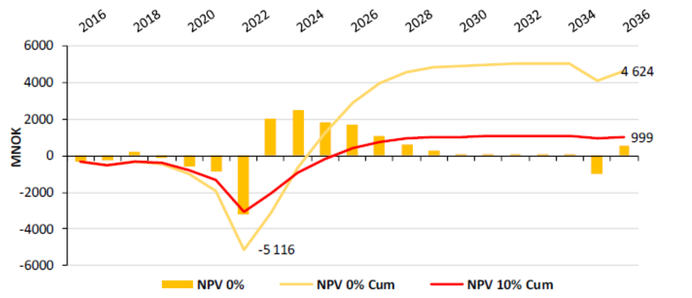
Economy

Premises for inflation rate, hydrocarbon prices and currency exchange rate were taken from WoodMackenzie for the untruncated mean oil volume economics. The economy summary table (left side Fig. 5.2) shows a positive net present value (NPV) with an internal rate of return (IRR) of 18.2 %. The NPV improves by ~20 % if the gas cap is produced. The oil break even price is estimated to $ 56.2/bbl. The largest modelled NPV sensitivity is recoverable volumes as seen in the sensitivities diagram (Fig. 5.2).

PL 779 (100%) NPV date January 2016	Unconsolidated economics Oil leg	
Basis for economic evaluation	**Gas**	**Oil**
Price in USD / boe (real)	50,3	85,0
NOK/USD	6,88	
Inflation p.a.	2,0 %	
Recoverable mean resources, MSm3 OE	0,88	6,15
Key Cost figures / KPI's		
Total EPEX, MNOK (real 2016)	1205	
Total CAPEX, MNOK (real 2016)	5505	
Total OPEX, MNOK (real 2016)	3928	
Total D&A, MNOK (real 2016)	980	
CAPEX/boe, USD	17,3	
OPEX (incl. Tariffs)/boe, USD	12,3	
D&A/boe, USD	3,1	
Key Performance Indicators		
Internal Rate of Return (IRR)	18,2 %	
NPV MNOK (10% nominal)	999	
EMV MNOK (10% nominal)	98	
Break-Even-Price oil (USD/bbl)	56,2	
Profitability - Index (P/I)	0,29	
Maximum exposure, MNOK (nom)	-5116	
Payback year of investments and expenditures	2025	

Economic Illustrations

Cash-Flow, Base Case



Sensitivities on NPV (MNOK)

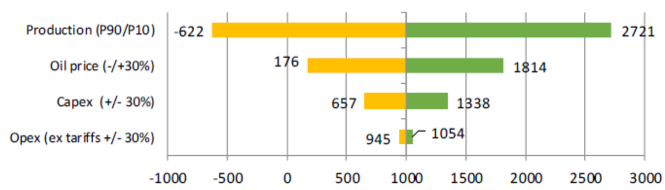


Fig. 5.2 Economic summary

Economic evaluation of the Mosterøy prospect using mean untruncated oil volumes.

6 Conclusions

PL 779 is located in a favorable position within proven plays and close to existing infrastructure. The main prospect Mosterøy in Upper Jurassic Intra Draupne Formation sandstones is located in an expected fairway for turbidite sands eroded from the northern Utsira High. These are interpreted to be derived from the same fairway system that has contributed to the Gudrun Field reservoir. There is still, however, risk associated with reservoir presence on a prospect level as it is challenging to tie this local accumulation to known presences of Intra Draupne Formation sandstones.

Special seismic data analysis involving partial stacks has not been found applicable in this area for the relevant lithologies. Upper Jurassic sandstones and shales are difficult to separate in the elastic impedance domain as learned from offset wells and known field examples.

The licence work has introduced a depositional model that predicts a better fault seal compared to pre-award (VNG et al., 2014). This has increased the seal factor probability from 0.4 to 0.7.

In addition to the Mosterøy prospect there is also additional prospectivity identified in the license area (VNG et al., 2014). The license group has not focused on maturing these during the license period. Observations from surrounding wells such as 16/1-7 and 24/12-1 indicate that that Middle Jurassic Hugin- and/or Sleipner Formation sandstones could be a reservoir in this area. An exploration well with Middle Jurassic reservoir(s) as secondary well target(s) could be an effective way to test several plays in one wellbore.

Upcoming wells in Q2/Q3 2016 include Ivar Aasen Unit's West Cable East pilot and PL 626's Rovarkula. The West Cable East pilot will appraise the West Cable Main discovery in the Sleipner Formation. The PL 626 Rovarkula prospect in Block 25/10 will target Upper Jurassic Intra Draupne Formation sandstones, but from a different fairway than expected for the Mosterøy prospect. Limited new relevant well data is therefore expected to affect the PL 779 reservoir interval evaluations.

The partnership did not succeed in agreeing on a drill decision for the main prospect Mosterøy. There were different understandings about fault seal integrity and the related probability estimation. The operator proposed an exploration well, but was not supported by any of the partners. Partner Fortis then proposed a license extension with a geological work program which was supported by Lundin. VNG and Suncor did not support the extension.

The license was therefore relinquished.

7 References

VNG Norge AS, Fortis Petroleum Norway AS and Lundin Norway AS, 2014, Application for part of Block 16/1 (APA 2014)

Ichron Limited, 2014, South Viking Graben and Utsira High Stratigraphic Database

RDR (Rock Deformation Research Ltd, now Schlumberger), 2013, Review of the Mosterøy Prospect

TGS Facies Map Browser (Northwest Europe)