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Relinquishment report PL270 / PL270B

Summary

Production license 270 was issued in April 2001 with an obligation to drill an exploration well on the license. The license group has drilled exploration wells 35/3-6, 35/3-7S & 35/3-7ST2, acquiring and processed a new 3D seismic data (IPN1201) as well as performing numerous G&G studies. The main prospects in the license are in the Lower Cretaceous Agat sandstone where discoveries had been made in the 35/3-2 and 35/3-4 exploration wells prior to the award.

All the discoveries in the license show a modest hydrocarbon column of gas of less than 65 m, restricted to the upper part of the Agat where reservoir quality is slightly poorer. The contacts measured in the wells are different in each case and the 35/3-2 well has a higher pressure, indicating limited connectivity in the area. Residual gas is seen wherever the Agat sandstones are penetrated outside of the gas column.

Geophysical analysis, calibrated against wells, gives good indications of hydrocarbon filled reservoir in several areas over the license. Unfortunately the relatively small change in hydrocarbon saturation between residual gas (typically 20%) and a free gas column (less than 60%) is expected to be below the resolution of the techniques applied. Areas with weaker geophysical response are therefore likely to contain residual gas or poor reservoir.

Despite multiple discoveries the trapping mechanism for these accumulations is still uncertain and this leads to large uncertainties in estimations of in-place hydrocarbon volumes. Assuming the geophysical analysis represents the true extent of the hydrocarbons, both the discoveries made and the remaining prospects are assessed to be too small to be economic. At the same time significant risks remain around development scenarios where a long pipeline to Gjøa would also be required to tolerate water production.

On 15th May 2014 VNG Norge proposed to the license group that PL270 & PL270B should be relinquished. On 17th September 2014 Atlantic Petroleum Norge As approved the relinquishment after being unable to attract a partner to continue the license.

1 Key license history

Production license 270 was issued in April 2001 to RWE Dea Norge AS and Aker Energy with an obligation to drill a well on the license. OER Oil As acquired Aker Energy AS's with its share in the license in December 2003. OER Oil As was subsequently purchased by Endeavour Energy Norge As which in turn was purchased by VNG Norge AS. In the summer of 2011 RWE saw no further potential in the license and elected to withdraw. On 1st September 2011 VNG Norge stood alone as operator with 100% equity in the license. The current license partnership was established on 27th December 2012 when Emergy Exploration AS (later Atlantic Petroleum Norge AS) entered the license with 15%. In February 2014 the partnership was awarded additional acreage as PL270B.

35/3-6 was drilled as the first well in the license in the spring of 2002. The well encountered a low impedance shale rather than gas filled, low impedance Agat sands previously identified in the license. It was TD'ed in the Late Jurassic Heather Formation was plugged and abandoned as a dry hole. The lessons from this well were used to interpret a new seismic inversion on the GP3D93R02 3D seismic data.

Well 35/3-7S was spudded in June 2009 to test a seismic anomaly in the GP3D93R02 seismic data indicating the presence of hydrocarbons. The well proved a gas column in the main bore and the side track (35/3-7ST2) and a comprehensive data collection program was undertaken including a mini DST, MDT sampling, coring, special core analysis and a full suite of wireline logs.

A new inversion of the GP3D93R02 data was commissioned from Schlumberger by the license, with the new well and side track included as additional control points. The results were promising but questions still remained and the license elected to acquire a modern 3D seismic survey over the area. IPN1201 was acquired during 2011 & 2012 together with PL578 who had also planned a seismic acquisition over the same area. A new inversion of this data was commissioned from Ikon Science in 2013.

With the additional data collected, the existing discoveries are all seen to be too small to be economic. The remaining Agat prospects in PL270 have a negative economy, with no single area able to support a development. At the same time many of the initial risks around trapping mechanisms and water production still remain. The combined risk of developing multiple areas with investigations in each also renders these development scenarios uneconomic.

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2 Database

The common seismic database has included:

- GP3D93R02 – A PSDM reprocessed version of the GP3D93 data. This was the key seismic data for the license prior to the acquisition of the new survey. At that point it was removed from the license database.
- IPN1201 – A survey acquired by the license together with PL578. This was processed as PSTM, PSDM controlled beam migration and PSDM Kirchoff migration.

The common well database has included all wells in the local area that have been released as well as 35/3-6, 35/3-7S & 35/3-7ST2.

Special Core Analysis (SCAL) performed by Weatherford laboratories on 43 plugs 1.5 inch core plugs from well 35/3-7S. In addition to this, 10 plugs were selected for mercury injection capillary pressure (MICP) at net overburden conditions. (Weatherford Laboratories, 2012). In addition to the regular SCAL program, Trondheim based company Lithicon did digital rock analysis including 3D pore network modelling to extract saturation end points, capillary pressures and relative permeability curves (Lithicon, 2014).

A biostratigraphical evaluation of 6 wells in quadrants N35 & N36, Norwegian North Sea by Ichron Limited. This report presents the results and interpretations of a biostratigraphical evaluation of wells 35/3-1, 35/3-2, 35/3-4, 35/3-5, 35/3-6 and 36/1-2 from the Agat area, Norwegian North Sea, with the integration of previously analysed well 35/3-7S. The combined stratigraphic interval under investigation encompasses the Cenomanian – Callovian (Late Cretaceous – Middle Jurassic). Samples analysed are ditch cuttings and conventional core pieces provided by the NPD. In cases where the rock material was not available the archive slides provided by NPD were utilised. (Ichron, 2013).

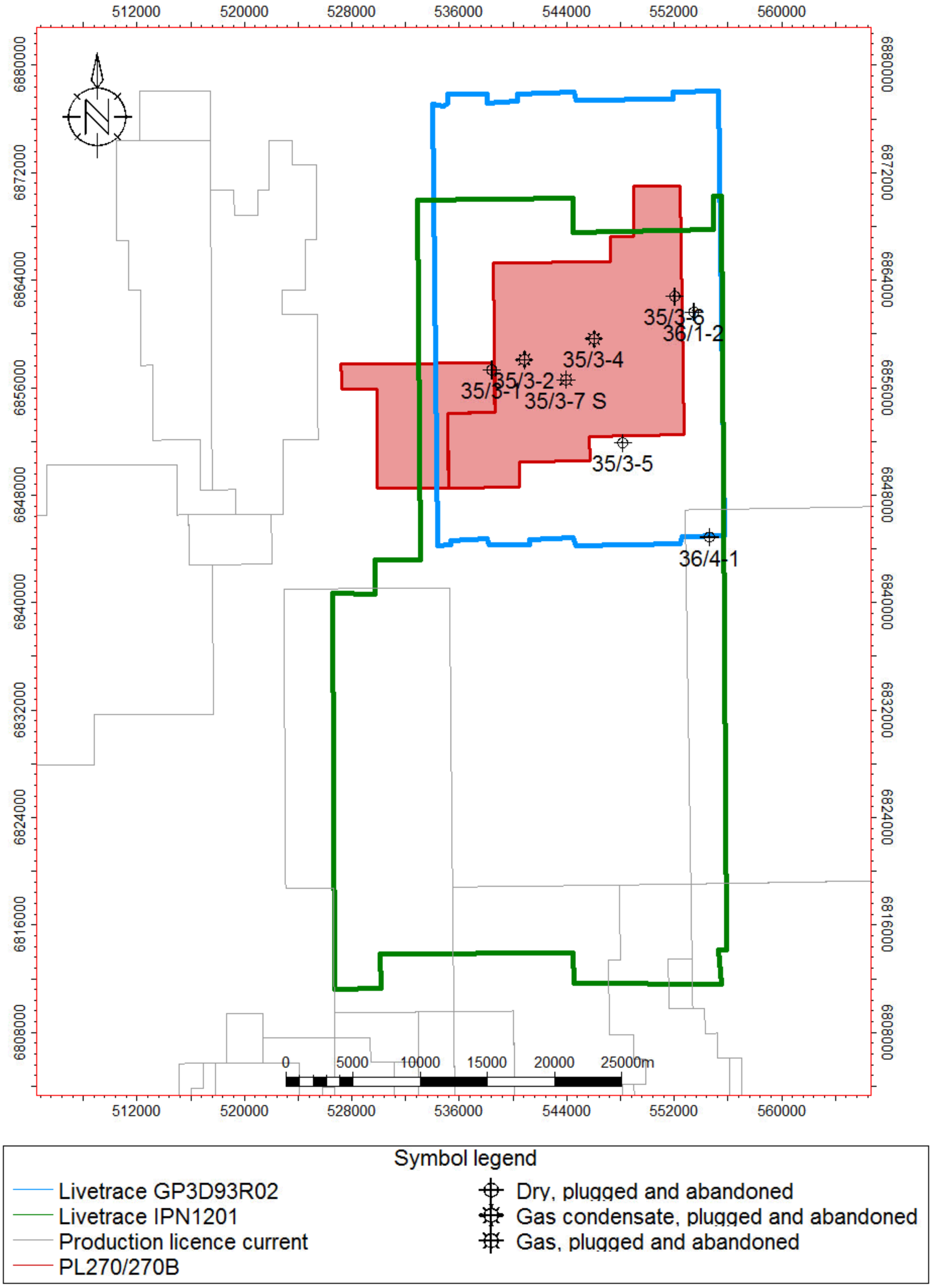

Figure 1. PL270 & PL270B Seismic and well database

3 Review of geological framework

3.1 Seismic interpretation

The new seismic data gives a significant improvement in the imaging across the license, particularly at and below the base Cretaceous unconformity. Glacial moraine in the area around the 35/3-4 well and significant channels in the shallow section still present challenges to seismic imaging. The new seismic data revealed that the small faults, previously inferred as the most likely trapping mechanisms for the discoveries, were not present.

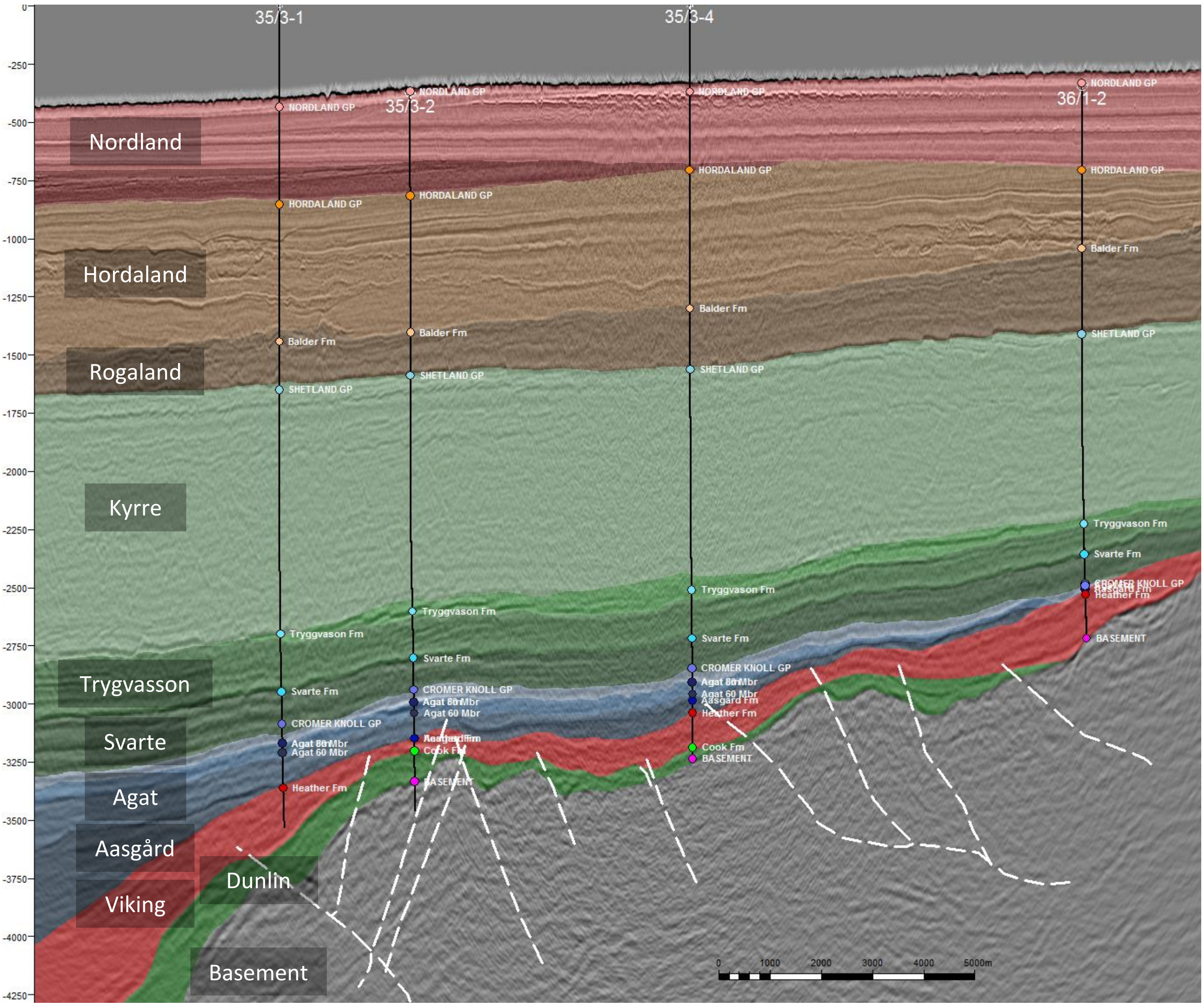

Figure 2. A seismic section in time through the wells 35/3-1, 35/3-2, 35/3-4 and 36/1-2 showing the local geological sequence.

3.2 Velocity modelling

As part of the reinterpretation of the new seismic data, a new depth conversion was performed. Velocities in the Kyrre Formation are key to building an appropriate velocity model as velocities in this unit are strongly affected by burial depth. Each metre of burial equates to an increase in velocity of approximately 1 metre per second. Complicating the issue is the fact that the coast of Norway experienced a significant uplift during the Neogene such that the effective depth of burial of sediments in the block is greater than that seen today. This effect increases towards the East and can be estimated using the velocity trends in the well.

With a general increase in velocities towards the West, the effect of this trend is to tilt the structures towards the West in the time domain. A depth conversion using these velocities therefore tilts the structure Eastwards again. With this new model the Agat reservoir around the discoveries in PL270 is very close to being flat, much more so than appears in the time domain. There even appears to be a small 4 way closure West of the 35/3-7 well. This closure is less than 50 m over an area of approximately 5 km x 2 km.

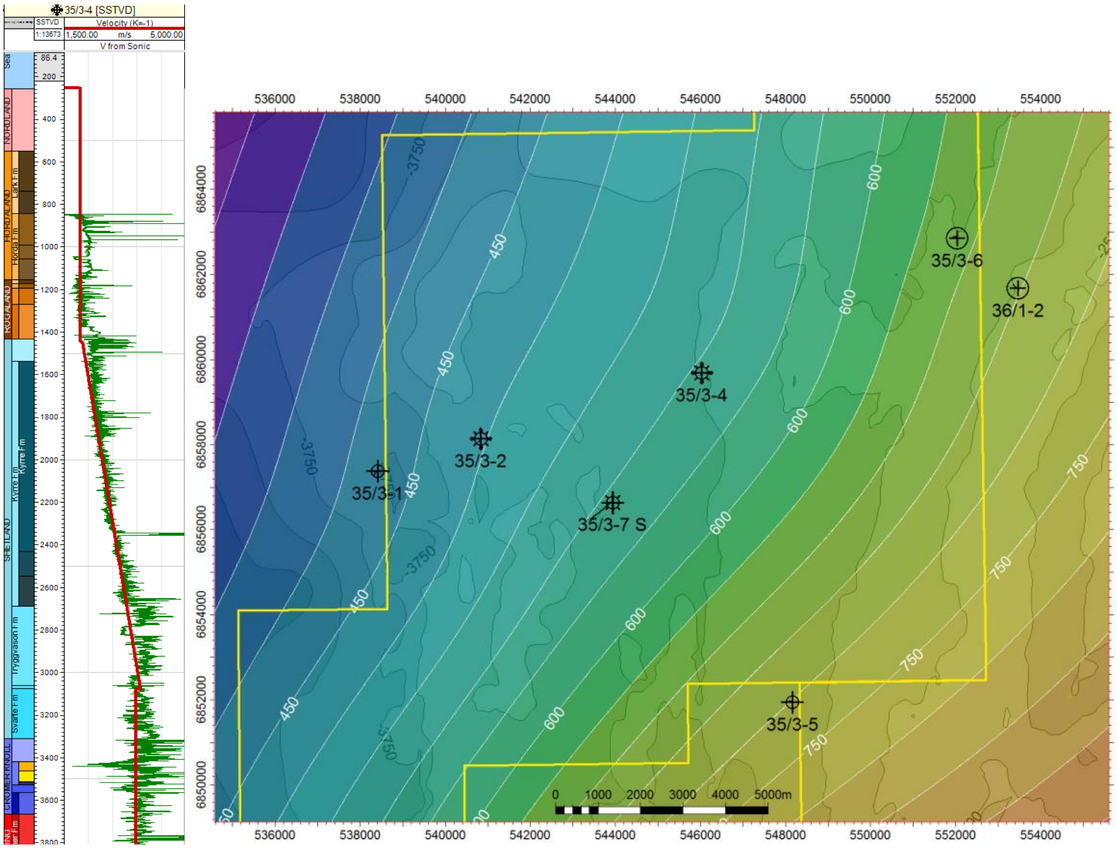

Figure 3. A log from 35/3-7 showing measured and modelled velocity. The Kyrre shows a significant increase with depth. To the right is a map of the modelled Vo velocities for the Kyrre across the license due to the Neogene uplift.

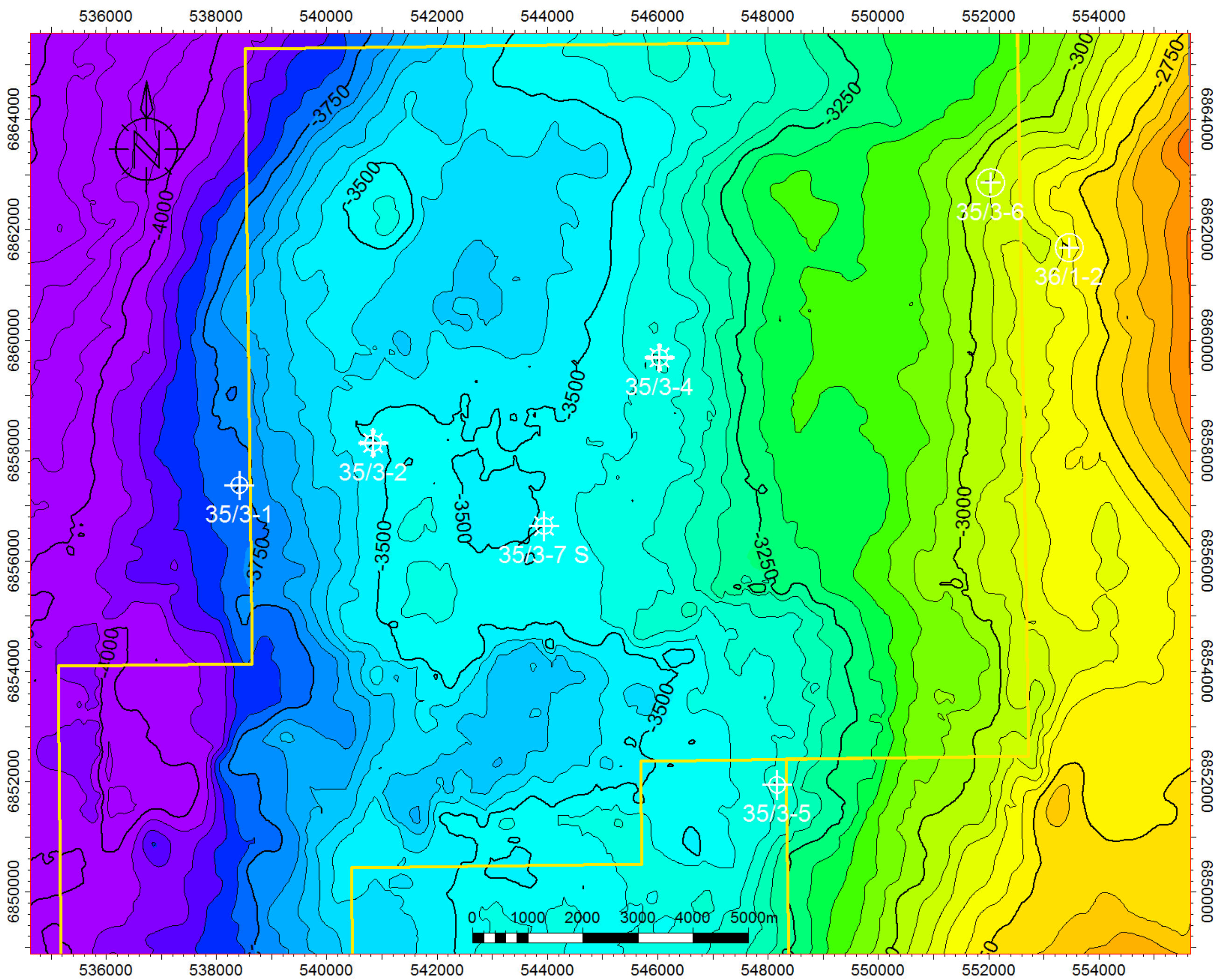

Figure 4. A depth map for the top Agat 80 horizon across PL270. There is a small structural closure West of the 35/3-7 well.

3.3 Sedimentology

Basement and Jurassic sediments all along the Måløy slope have a classic North South orientated rotated fault block geometry. Late Jurassic and Early Cretaceous shales have filled inn this topography before compacting to leave a softer, remnant topography in the Early Cretaceous. The deep marine Agat sand systems are clearly affected by this topography, converging to cross the footwall highs in thin strips at the lowest points and avoiding the high points completely. A lithostratigraphic column for the area as described by Norlex is shown in Figure 5 (Norlex, 2014) (The NPD lithostratigraphic charts do not include the Agat Formation).

Re-logging of the cores in the Agat wells has established a progression in the system from predominantly shale deposition in the lowermost Agat (Agat 60 and older), through good, high density turbidite sands (Agat 70) to debris flows and low density turbidites (Agat 80 and Agat 100). This progression is interpreted as a deep marine system building out with shales, then turbidite lobes (Agat 70, see Figure 6) subsequently cut by channelised deposits as sands were delivered further out into the basin (Agat 80, see Figure 7). These channelised deposits probably developed in broad, semi confined channels. Low density turbidites would have been deposited off axis in the channel, as the main body of the turbidite passed through the system. During quiet periods shale would accumulate in the channel system. When the system was reactivated this shale would be disturbed and re-deposited in the channel as debrites.

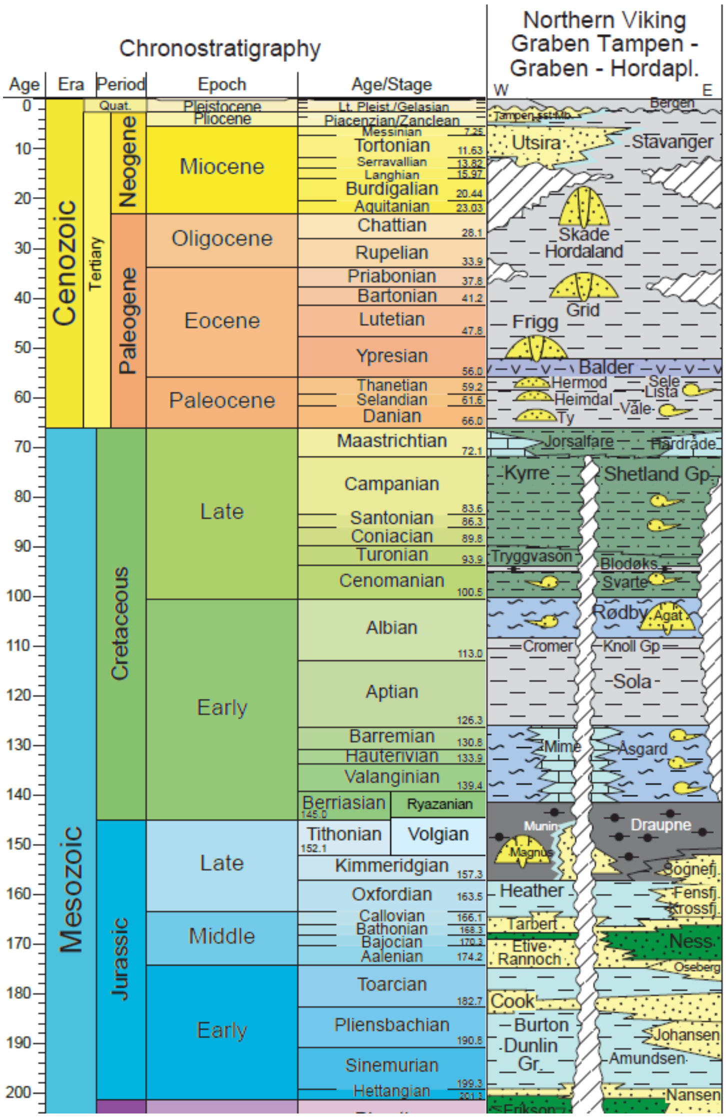

Figure 5. A stratigraphic column for the Northern Viking Graben including the Måløy slope and PL270.

By the time of deposition of the youngest Agat sediments, a well-established channel system was in place, efficiently delivering sand out into the Sogn Graben (Agat 100, see Figure 8). The head of the channel has progressed beyond the next footwall high, tapping into additional accommodation space and the channel has become entrenched & static for the first time. It is also the first time this channel system is clearly visible on seismic. Most of the sand is delivered out into the basin, by-passing this area and the Agat sediments are mostly fine sand and shales.

Hydrocarbons discovered in the 35/3 block are seen almost exclusively in the poorer Agat 80 channel complex sands and rarely in the more blocky Agat 70 high density turbidites. As to why this is the case, and what is trapping the hydrocarbons in these sands is the critical question for the Agat prospects.

Well 35/3-5 has always been seen as being slightly anomalous compared to the other wells in the block. There is significantly more sand in the sequence, sand in the Agat 100 and a lack of hydrocarbons. Agat 80 as a seismic pick is straightforward over much of the block, but becomes ambiguous in the area of the 35/3-5 well. With the new seismic data it seems possible that the Agat 100 channel is a more significant feature than first thought, cutting down through the older Agat sands and subsequently back filled.

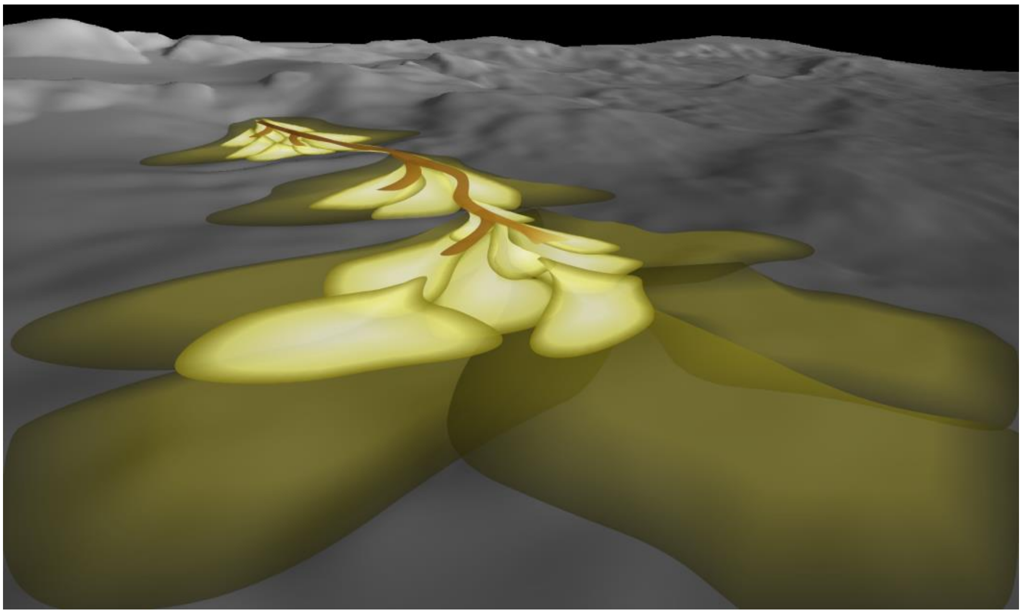

Figure 6. Agat 70 deposition. Turbidite lobes are deposited on low lying areas on a flat area behind the last footwall high before the Sogn Graben.

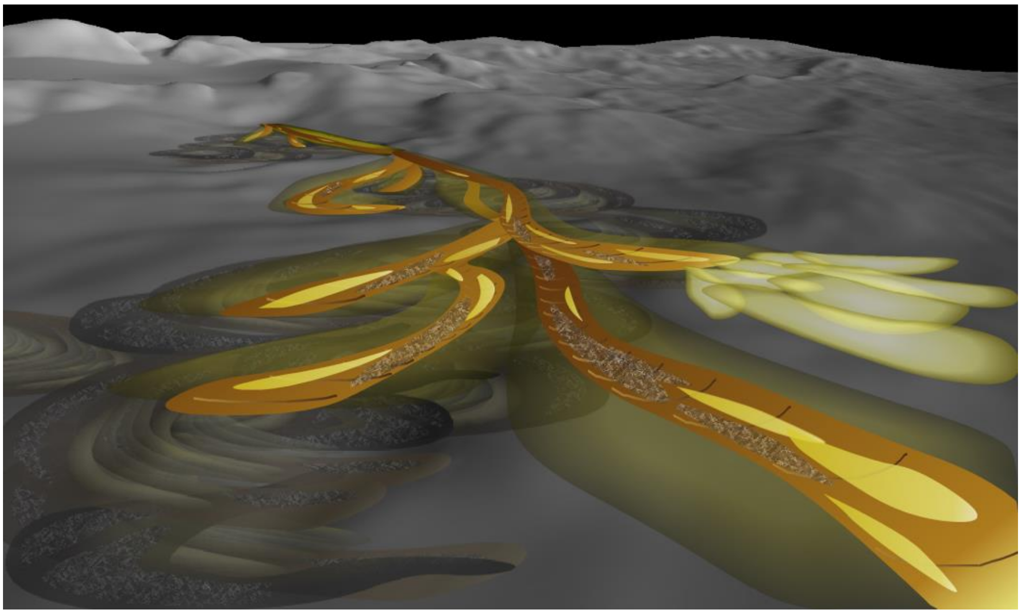

Figure 7. Agat 80 deposition. The system has prograded and now a channelised system deposits debrites and intra channel sands above the cleaner lobes.

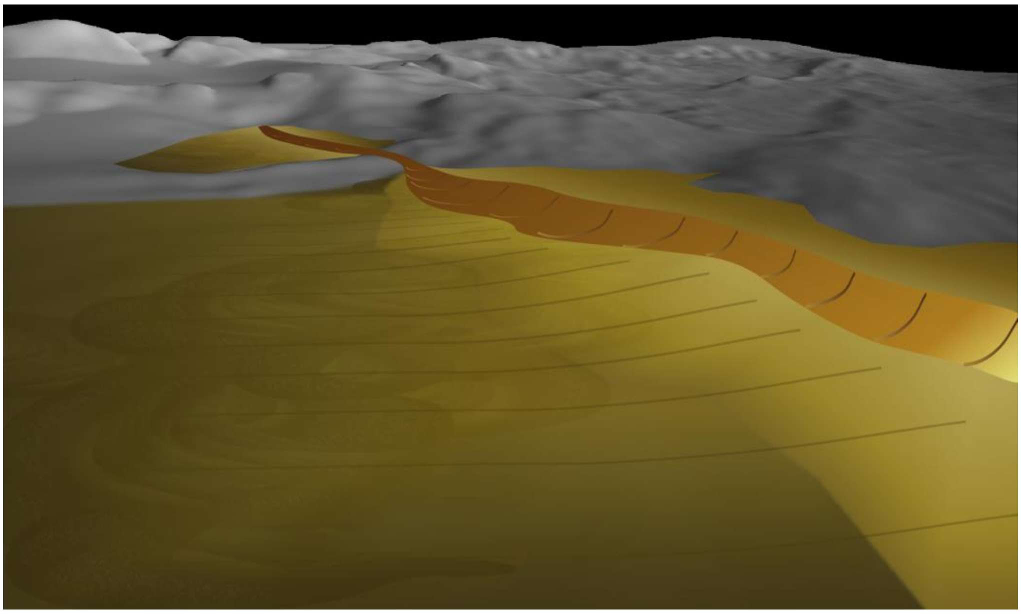

Figure 8. Agat 100 deposition. The prograding system has reached the edge of the Sogn Graben. It becomes entrenched and therefore confined across the PL270 fault block allowing development of potential channel levees.

4 Prospect update

Three gas discoveries have been made in Agat sandstones within the PL270 license. In two of these wells successful tests were completed where hydrocarbons flowed to the surface at economic rates. Despite this the trapping mechanism for this prospect is still uncertain. Without a good understanding of the trap, estimating in place resources is challenging. Exploration in the license has therefore focussed on understanding the trap and mapping hydrocarbon distribution by other means.

4.1 Petrophysics

With new SCAL data in the 35/3-7 well, a re-evaluation of the petrophysical interpretation in all of the wells was performed. Key findings include;

- The density logs in the Agat section are heavily affected by even small amounts of washout. Alternative models for estimating porosity were used in these areas and a corrected density log was back calculated.
- 35/3-7 probably suffered from invasion of drilling mud in areas with lower permeability sand. This well was drilled with considerable overbalance to mitigate the risk that the pressure would be similar to that in 35/3-2. This was accounted for in the corrected density log.
- SCAL data reveals that the m & n parameters used for estimating saturation are far from the standard values used previously.
- The water is very fresh.
- 35/3-1 was probably a small discovery in both the Agat level and the Jurassic but was drilled with considerable overbalance such that this was not recognised at the time.

There are three main consequences of these findings:

Density – The corrected density logs made it much easier to perform an accurate well tie and explained some of the unusual features of earlier inversion studies. A new inversion study was undertaken with this data as input together with the newly acquired seismic.

Saturation – Water saturation was remodelled taking into account the water salinity, the new data from SCAL and records of shows in the cuttings descriptions. Updated gas saturations indicate that almost all of the Agat sands encountered have some residual hydrocarbons, often over 20%. Gas saturations within the sections with a column, are rarely higher than 60%.

35/3-1 – The potential discoveries in 35/3-1 were investigated.

4.2 SCAL data

As well as input to the petrophysical parameters for saturation modelling and key data for flow modelling, the SCAL provided saturation functions and relative permeability curves which have a significant impact in our understanding of the prospectivity.

Saturation pressure curves show a much larger transition zone than would generally be expected in this type of reservoir. At 10 mD, an 80 m column is required to reach 50% gas saturation.

Mercury injection tests measure the volume of mercury entering the pore network at a specific fluid pressure. As the pressure is increased, the mercury is able to squeeze through increasingly narrow pore throats, accessing more pore volume. Where the pores are rugose, the fluid (mercury in this case) will initially only occupy a limited volume. As the pressure increases the fluid is able to invade rough pore edges occupying more of the pore volume. This test therefore provides a measure of the distribution of pore throat size combined with a measure of pore rugosity.

In the Agat core samples these tests show wide, occasionally bi-modal pore size distributions. This is thought to be the key reason for the unusual pressure curves. Gas enters the largest pores relatively easily and this network is connected such that the permeability of the rock is reasonable. However digenetic clays, mostly kaolinite booklets and radial chlorite, then reduce the accessibility of a significant amount of the remaining pore space. Relatively high gas pressures are required to displace the water around the edges of these rugose pores i.e. a high gas pressure is required to achieve high gas saturation.

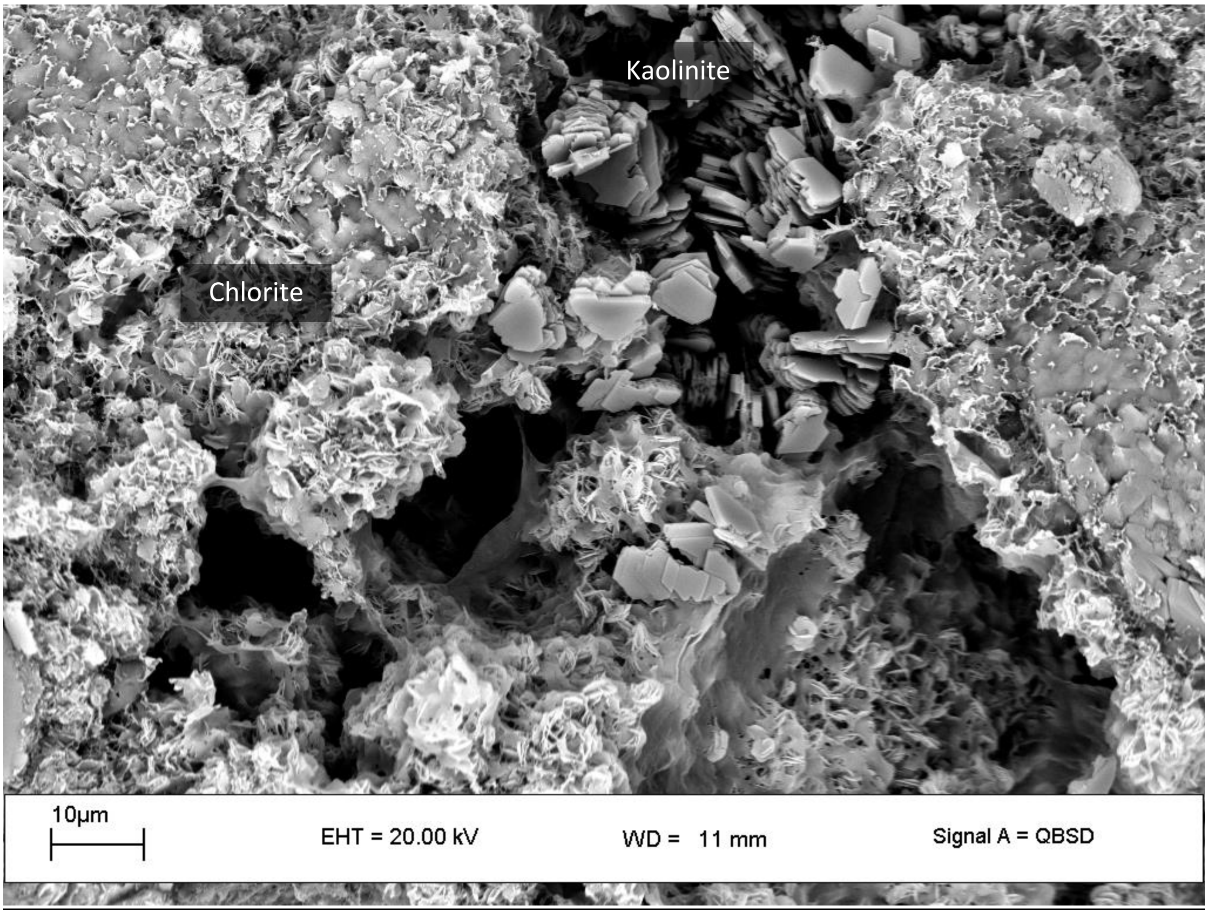

Figure 9. A scanning electron microscope image of pore space in the Agat sandstone. Open, well connected pores are surrounded by diagenetic clays.

Measured water saturation pressure curves were verified by modelling expected water saturation in the wells. By substituting height above contact for pressure and estimating permeability from porosity it was possible to create estimated water saturation logs. These logs gave a reasonable match to the water saturation estimated from log data and thus support the findings from SCAL.

The higher entry pressures for a significant percentage of the pore spaces also have an effect on the relative permeability of the various phases. Even reservoir samples with relatively high permeability see a drastic reduction in the water relative permeability with decreasing water saturation. This effect explains how it is possible to produce only gas in a reservoir with a water saturation close to 50%. The water phase is essentially immobile because of the rugose nature of the pore spaces. Meanwhile the gas is in the large, connected pore spaces and can be relatively easily produced. The final end point saturation for gas is in the normal range as described in the literature.

4.3 Geophysical analysis

With no clear trapping mechanism the Agat prospects have relied heavily on support from seismic data analysis. An in house study and a new inversion performed by Ikon, made use of the revised petrophysical data and the new seismic to investigate the presence of gas filled sand in the Agat section.

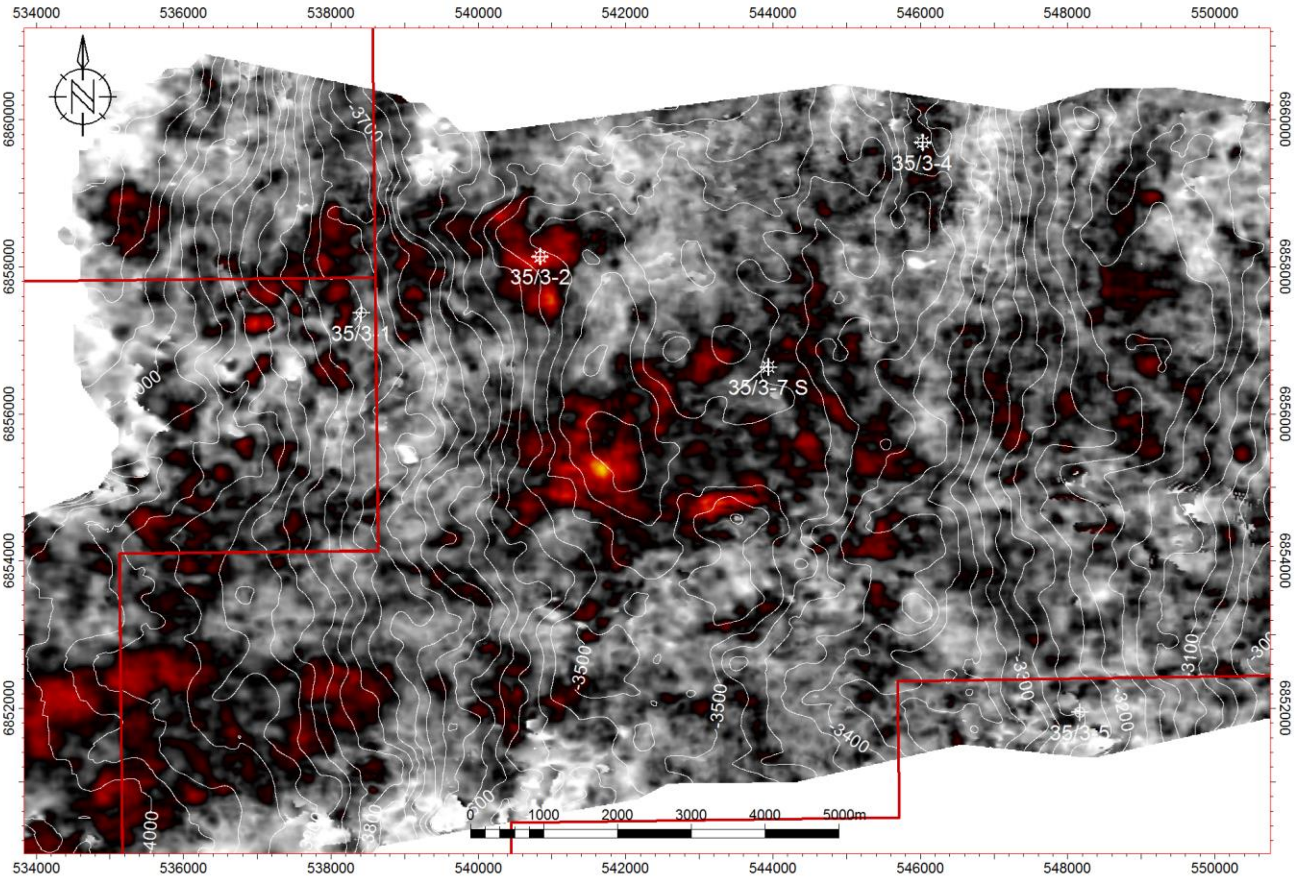

Figure 10. A seismic attribute indicative of gas filled reservoir, extracted from within the Agat 80 sequence. The contours are in depth (m).

Previously the most promising area in the license has been North East of the 35/3-7 well. With the new data this is no longer the case, although various methods of seismic analysis highlight the same 3 clear anomalies in Agat 80.

- Around the 35/3-2 discovery,
- Around and West of the 35/3-7 discovery in a small structural closure,
- 8 km further South West of the 35/3-7 discovery in the Jaspis prospect.

Figure 10 shows the maximum trough below the Agat 80 pick, extracted from the inverted extended elastic impedance cube. A trough in this context is an indicator of gas filled reservoir.

A similarly strong anomaly is also seen at the Agat 100 level although this passes directly through the 35/3-5 well where only residual hydrocarbons were encountered. This highlights one of the key issues with this analysis. Synthetic studies performed by the license have shown that the residual gas saturations in the Agat reservoir (often over 20%) are indistinguishable from the response from a hydrocarbon column (rarely over 60%). Without a good understanding of the trap and a conceptual model of where the hydrocarbons are likely to accumulate it is therefore difficult to rely on this data away from the existing discoveries.

4.4 Discoveries

There are 3 discoveries drilled within the license, all of which are thought to be independent accumulations.

4.4.1 35/3-2 & 35/3-1

35/3-2 has a significant pressure difference from the 35/3-7 well and the new seismic indicates that the reservoir is absent between these two wells. The seismic anomaly at this location is very strong, almost certainly enhanced by tuning, although the pressure data from 35/3-2 indicates a relatively small column. Petrophysical analysis from 35/3-1 indicates that this may have been a discovery that went unnoticed (see section 4.1) and seismic attribute maps give indications of gas filled reservoir between these two wells. However the contact measured in 35/3-2 is well above top reservoir at 35/3-1 and the two are therefore not connected. Any hydrocarbons between these two wells are therefore likely to be either multiple, small, disconnected accumulations or residual gas. The estimated volume of this accumulation, 0.3 Bm^3 recoverable gas, is too small to be economic.

4.4.2 35/3-4

35/3-4 is located on a flatter section of the structure at the two of a steep slope with no seismic anomaly. The trapping mechanism, and therefore the extent of the accumulation is therefore uncertain. The well is in an area of poor seismic quality due to interference from shallow moraine. There is a small seismic anomaly but it is not widespread. The estimated volume of this accumulation, 0.36 Bm^3 recoverable gas, is too small to be economic.

4.4.3 35/3-7

The latest data puts the 35/3-7 discovery on the northern edge of a small structural East West closure that broadly coincides with seismic anomalies. To the North the Agat reservoir pinches out. Closure to the South is more problematic where we expect to see good sand in a section running up to the dry 35/3-5 well. The estimated volume of this accumulation, 1.9 Bm^3 recoverable gas, is too small to be economic without an established pipeline.

4.5 Prospects

The previous main prospect in the license, North East of the 35/3-7 well no longer shows a good seismic anomaly. There is no trap defined and the prospect is no longer considered valid. Two of the original prospects are still considered valid and have been assessed.

4.5.1 Jade

Jade shows a clear seismic anomaly in the Agat 100 section close to the Eastern boundary of the license. At this point the Agat 100 is anticipated to pinch out as it crosses the uplifted Jurassic footwall underneath which provides the trapping mechanism. Seal to the South is problematic where a large sandy channel (drilled in 35/3-5) crosses the prospect. The prospect as defined by the extent of the seismic anomaly is too small to be economic and a larger extent has a substantial trapping risk.

4.5.2 Jaspis

The Jaspis prospect is based on a seismic anomaly South West of the 35/3-7 well and was the focus of the license extension PL270B in APA 2013. This area has one of the strongest anomalies in the license but the anomaly continues deep into the Sogn graben. Because of this there is a significant risk that this response is set up by residual gas rather than a column. Although the anomaly clearly dies out up dip, there is no seismic evidence of a fault or pinching out of the reservoir, which may create a trap for this prospect. At close to 4 km depth the prospect is around 500 m deeper than the discoveries in the license. There is therefore also a risk that the quartz overgrowths seen in thin sections from the other wells, are more extensive here.

Using an arbitrary contact height at 4000 m (the lowest strong seismic anomaly) the mean recoverable gas is estimated at 5.8 Bm^3. This is below the minimum economic field size in this area.

5 Technical evaluations

5.1 Development considerations

Given the high water saturation, the lack of a base seal and the large capillary transition zone there is a risk of producing water in this reservoir. Whilst the two well tests produced very little water (the tests lasted for 16 hrs), simulation on reservoir models in the areas around the wells indicate that water breakthrough can occur at any time during production. The low relative permeability of water means that there is likely to be little warning before this occurs and when it does the well effectively ceases to produce.

5.2 Development solution

The development scenarios tested are based on two four slot templates (above the two prospects) tied back along a 50 km pipeline to Gjøa.

Given the risk of producing water in this reservoir, any development solution must be able to cope with water production. Alternative systems for hydrate prevention include continuous MEG injection and DEH (Direct Electrical Heating). MEG systems are sensitive to scale precipitation and therefore only able to deal with relatively small volumes of water. DEH would therefore be the chosen option although this represents an increase in cost and risk due to the limited experience of such a system in the industry.

5.3 Appraisal

With a number of previous discoveries on the license and a poor understanding of the trapping mechanism, an additional, standard exploration well is not expected to significantly narrow uncertainty or mitigate any of the risks in the project.

If one assumes that the current geophysical picture of hydrocarbon distribution is reliable, the key risk is that producers experience early water breakthrough. To mitigate this it has been proposed to drill the next appraisal well as a horizontal well. This would then be completed as a producer to enable a long test and confirm the reservoirs production capacity over time, before committing to a development.

Whilst the proposed well would increase confidence that the reservoir was sufficiently connected to produce over time, there would be no guarantee that a well that had a good test for 1 month would be able to produce for 6 months or 1 year. Such a well would also be difficult to complete with respect to choosing a zone for perforation. The gas water contact in the reservoir has been different in each well in the license and it has not been possible to differentiate between free and residual hydrocarbons based on log data.

6 Conclusions

In a standard workflow the trap would be defined by mapping, gross rock volume calculated, possibly supported by geophysical analysis and then tested by a well. With a contact identified, a range of recoverable volumes can be estimated.

Despite detailed seismic interpretation, mapping, seismic attribute analysis and seismic inversion, the trapping mechanism for the discoveries in PL270 are not well understood. The outline of the discoveries is therefore very uncertain and reliable estimates of recoverable volumes are problematic, despite the large number of wells in the area. No realistic scenarios with a significant upside have been identified.

Advanced geophysical analysis has been an important element for these prospects and there have previously been indications that it is possible to differentiate between wet and hydrocarbon filled reservoir. Recent petrophysical data however demonstrates that residual gas is extensive in the license and present at saturations close to that seen in the discoveries. Geophysical analysis is not expected to be able to differentiate between free and residual gas in this reservoir.

In addition to the volumetric uncertainty, significant risks are associated with the development of these prospects specifically around; placing production wells, completing wells and transporting gas through a 50 km heated pipeline back to Gjøa.

The limited volume of recoverable hydrocarbons and considerable risks in the project mean that the discoveries made to date and the remaining prospects in PL270 all have a negative economy.

No other viable prospects have been identified in the license.

7 References

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