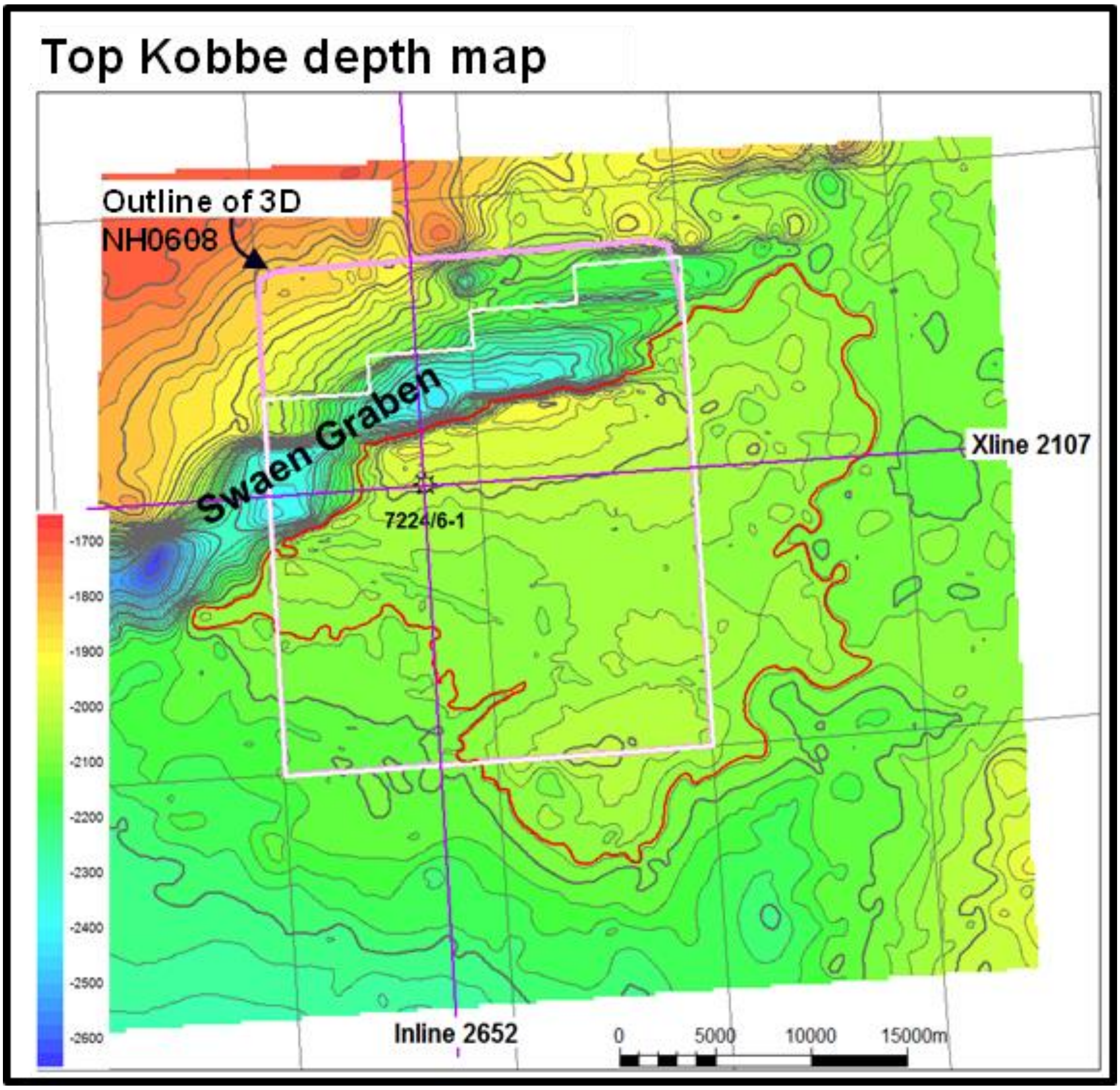
Relinquishment Report PL709



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1 Introduction and background

License PL709 was located on the Bjarmeland Platform, south of the Swaen Graben, north-east of Loppa High and West of the Nordkapp Basin (Figure 1). The acreage was awarded following the 22nd concession round with the following partnership: *Det norske oljeselskap ASA, operator (40%), Tullow Oil Norge AS (40%) and GDF SUEZ E&P Norge AS (20%)*.

PL 709 covered parts of the former PL 394 license where well 7224/6-1 was drilled in 2008. This well encountered low saturation gas in the Tubåen Formation and gas at 4 levels in the Kobbe Formation. Due to tight formation only one gas sample was retrieved in the Kobbe Formation at 2080m.

Following the encouraging test of the Norvarg discovery in former PL535, there was renewed interest for the Kobbe Play on the Bjarmeland Platform. Based on the renewed interest, Det norske together with Spring and GdFSuez applied for the PL709 acreage.

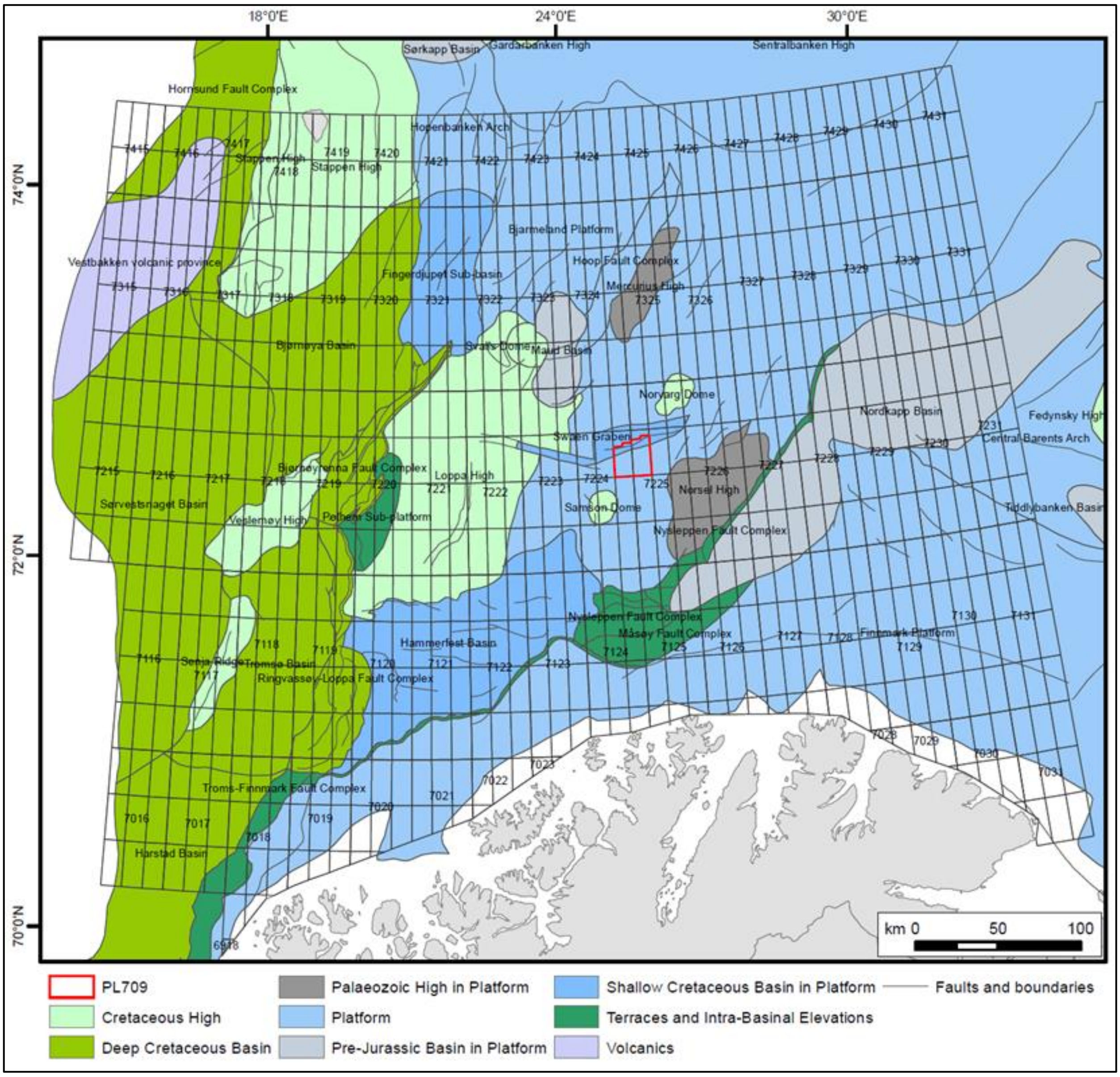


Figure 1: Location map, PL709

1.1 License award and work program

PL709 was awarded 21.06.2013 following the 22nd concession round.

License work program:

- Acquire and reprocess 3D seismic within awarded acreage
- Drill or Drop within 3 years of license award
- Drill well and BOV within 5 years

The initial work obligations are completed, and the work have resulted in a decision to relinquish the license.

1.2 License prospectivity

The prospectivity of the license, as presented in the application, was driven by the successful test of the discovery well (7225/3-1) on the Norvarg structure. The main prospectivity was located within the Kobbe Formation, where gas already had been proven by well 7224/6-1. Additional leads had been identified in the Snadd and Gipsdalen Formations.

The main prospect was the 3-way dip closure at Kobbe level (Figure 2). The Kobbe reservoir was believed to be deposited in tidal/coastal plain setting with tidal channels, tidal flats and overbank deposits (Figure 3 and Figure 4)

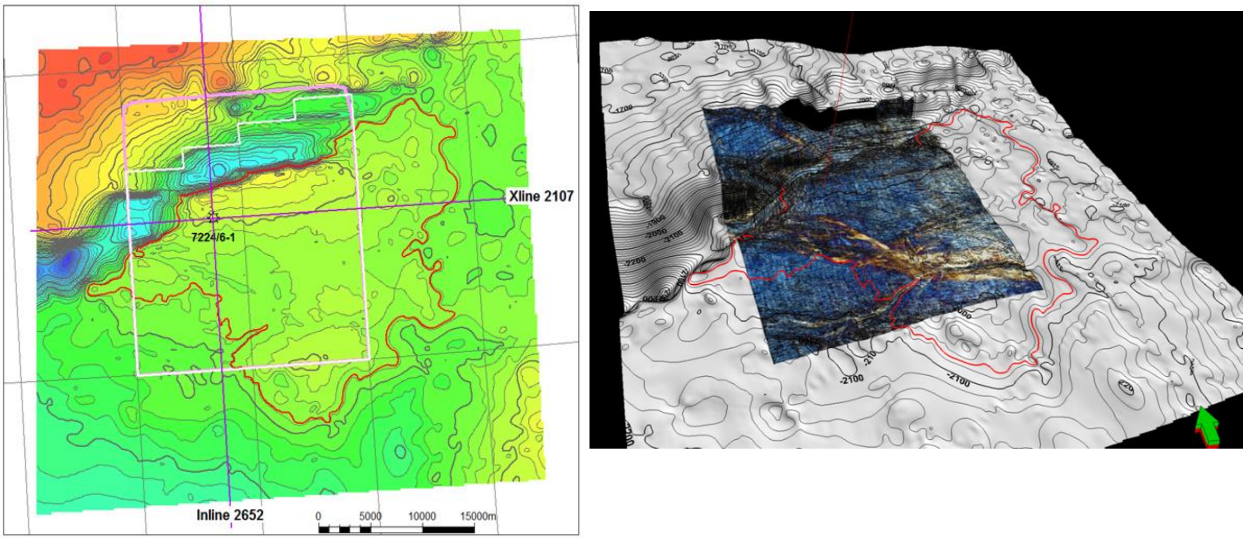


Figure 2: Depth structure map (left) and 3D view (right) of the Top Kobbe Formation. Right picture is a frequency blend of of NH0608 within the Kobbe Formation showing the major channel in at the Kobbe reservoir level

The CPI from 7224/6-1 shows gas at several different leves in the Kobbe Formation (Figure 5). However the reservoir properties of Kobbe at the well location were poor, with low N/G, low permeability and low porosity.

Based on seismic interpretation and well results from Norvarg it was seen that the Arenaria well was drilled outside the seismic visible channels. The theory was that if a well was placed within the channel, substantial better reservoir properties could be encountered. Producers could then be placed within high N/G channels and gas could be produced from the low N/G background facies.

Prospect volumes and risk for Arenaria on license award are listed in table Table 1

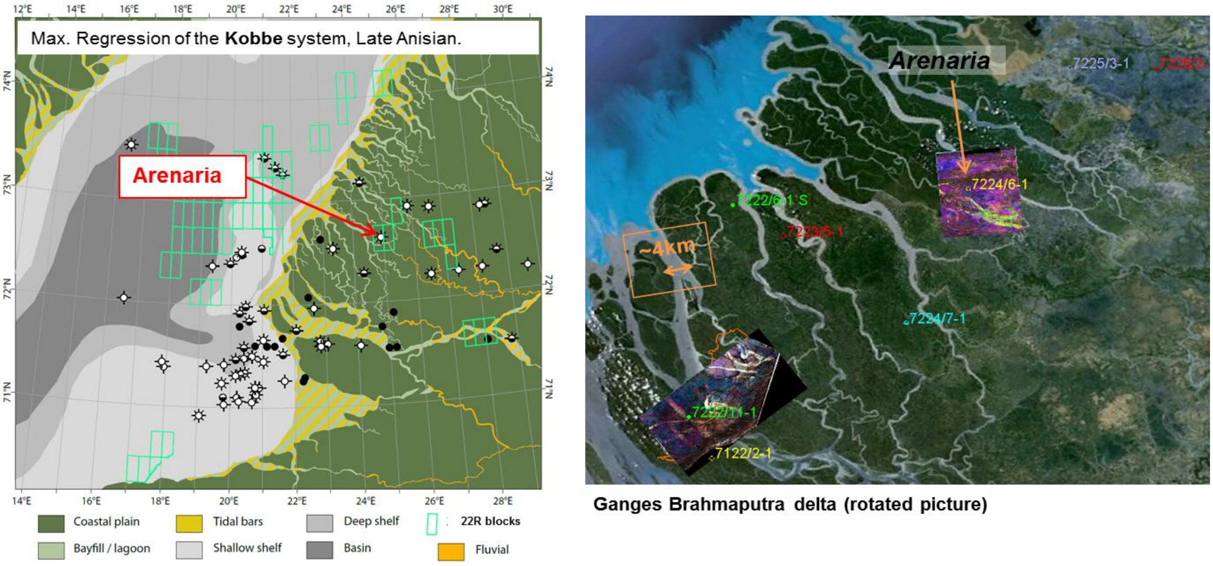


Figure 3: GDE map of the Kobbe Late Anisian system (left) and the Ganges Brahmaputra as a modern analog (right). On the right picture, Frequency blends from Langlitinden (PL659) and Arenaria (PL709) have been superimposed with the same scale as on the Ganges delta.

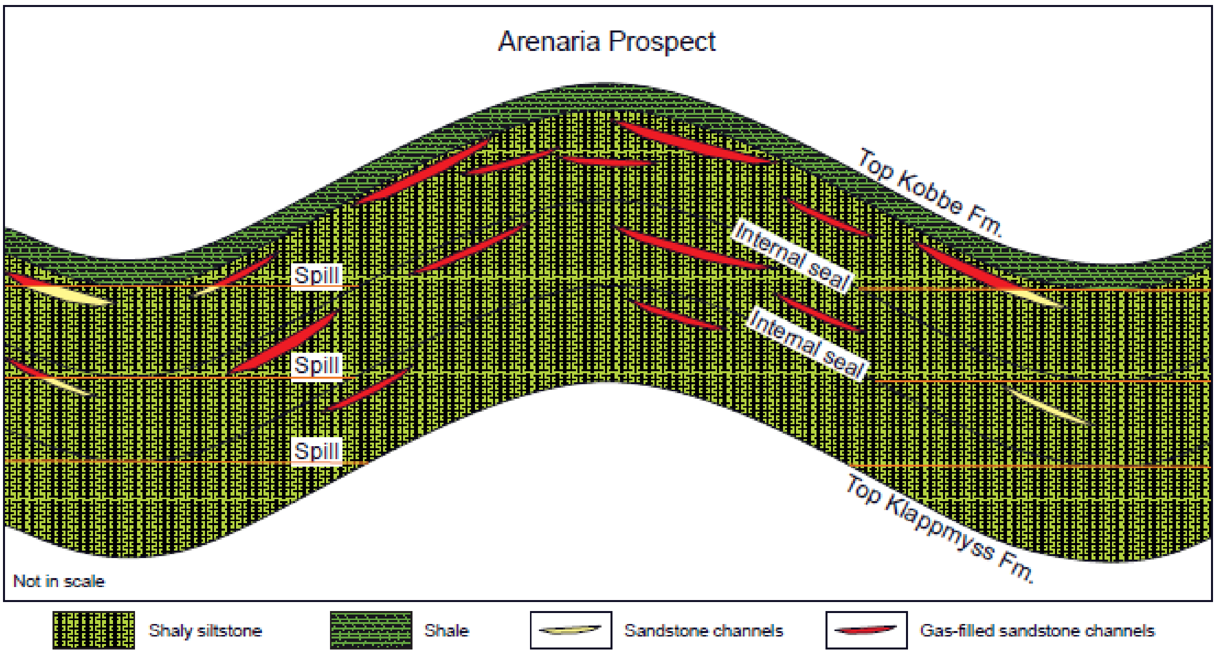


Figure 4: Schematic model for the Arenaria prospect. Stacked reservoir model, with internal barriers giving room for different gas water contacts within the structure at Kobbe level.

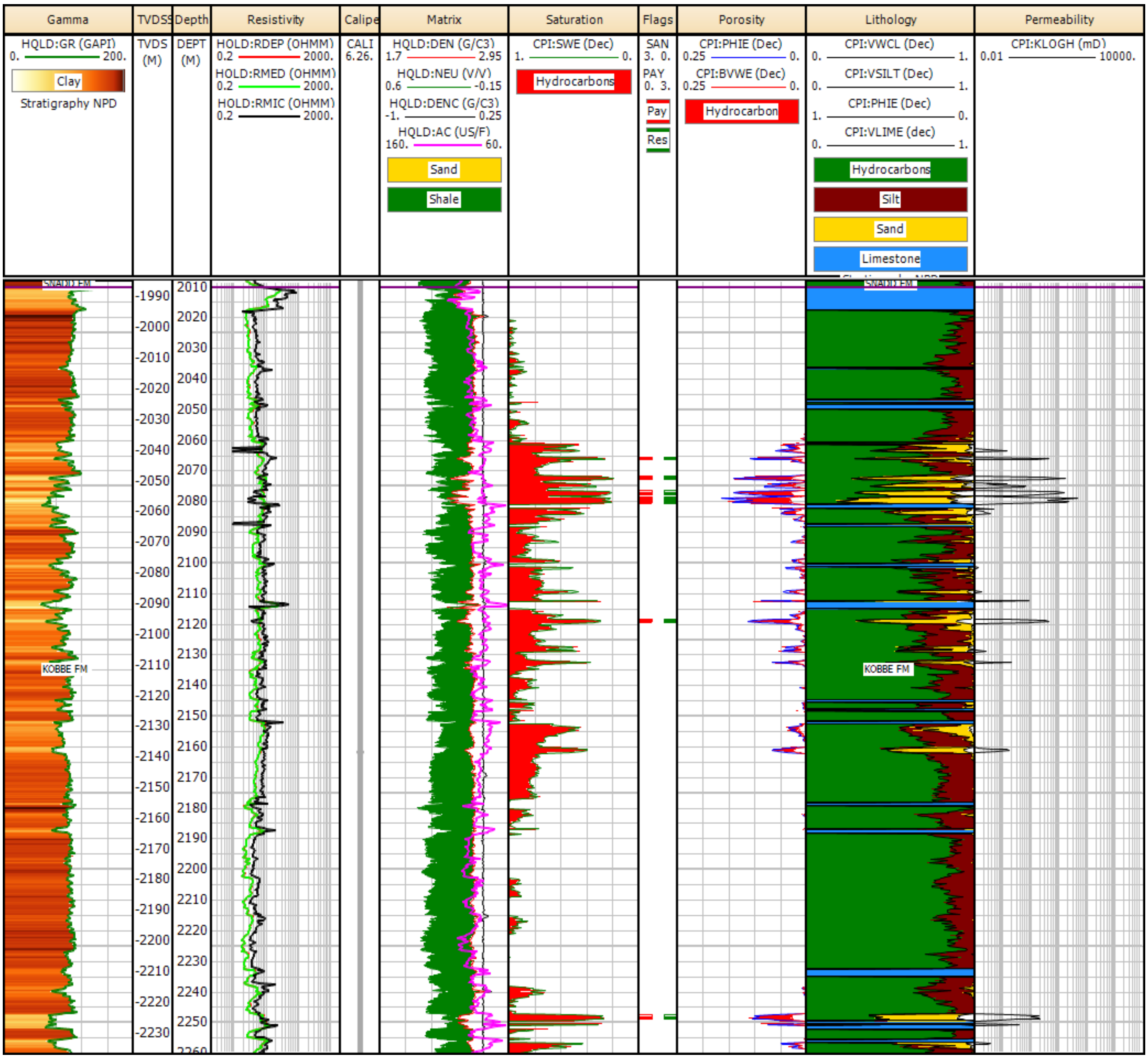


Figure 5: CPI of the upper Kobbe interval, 7224/6-1.

Discovery/ Prospect/Lead name	D/ P/ L	Unrisked recoverable resources						Probability of discovery %	Resources in acreage applied for %	Reservoir		Distance to infra-structure (km)
		Oil $10^6 Sm^3$			Gas $10^9 Sm^3$					Litho-/ Chrono-stratigraphic level	Reservoir depth (m MSL)	
		Low	Base	High	Low	Base	High					
Arenaria	P	1,4	2,1	3,0	34,9	52,9	73,6	32	64	Kobbe Fm/ Anisian	1900	220 km to Melkøya

Table 1 : Recoverable resources on license award.

2 Database

2.1 Seismic database.

The common seismic database consist of both 2D and 3D seismic data (Figure 6). NH0608 was the 3D included in the database, and reprocessing of this survey formed the basis for the work program. The 2D seismic consisted of ST8611 and a selection of NBR lines (Figure 6 and Table 2).

Survey	*Line number*
NBR10	346414B
NBR06	251430
NBR06	135996
NBR08	247114
NBR08	139718
NBR08	138755
NBR08	135996
NBR07RE09	248143
NBR07RE09	245945
NBR07RE09	247114
NBR07RE09	251059

Table 2 : List of NBR lines used in the common database

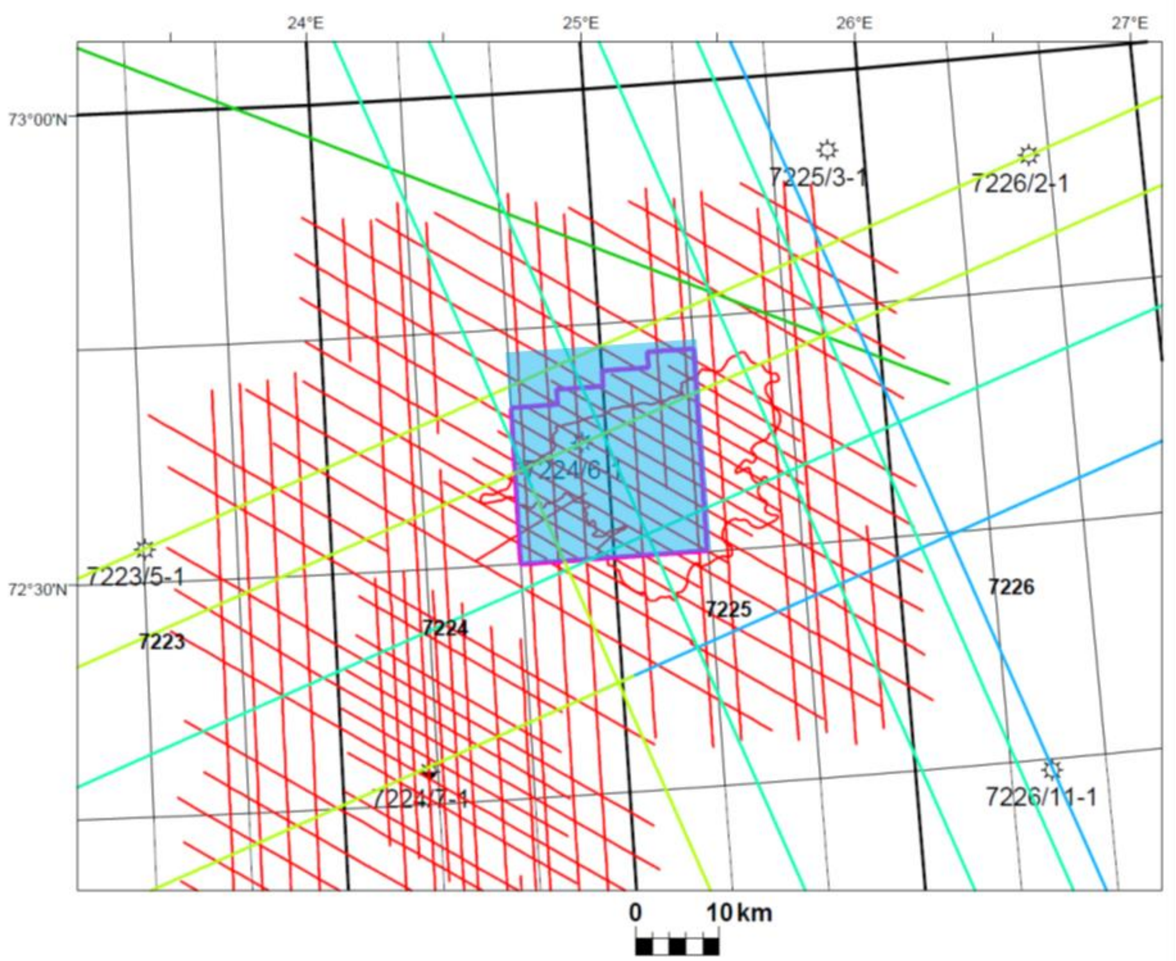


Figure 6 : Common seismic database. 3D survey NH0608(blue), ST8611(red) and NBR-lines.

2.2 Well database

The well database for the license included all released wells on the Bjarmeland Platform that had TD in or through the Kobbe Formation (Table 3, Figure 7).

Well name	*Structure*
7222/11-1	Caurus
7222/6-1	Obesum
7223/5-1	Obesum
7226/11-1	Norsel
7224/7-1	Samson Dome
7225/3-1	Norvarg Dome
7225/3-2	Norvarg Dome
7226/2-1	Ververis
7224/6-1	Arenaria

Table 3: Common well database

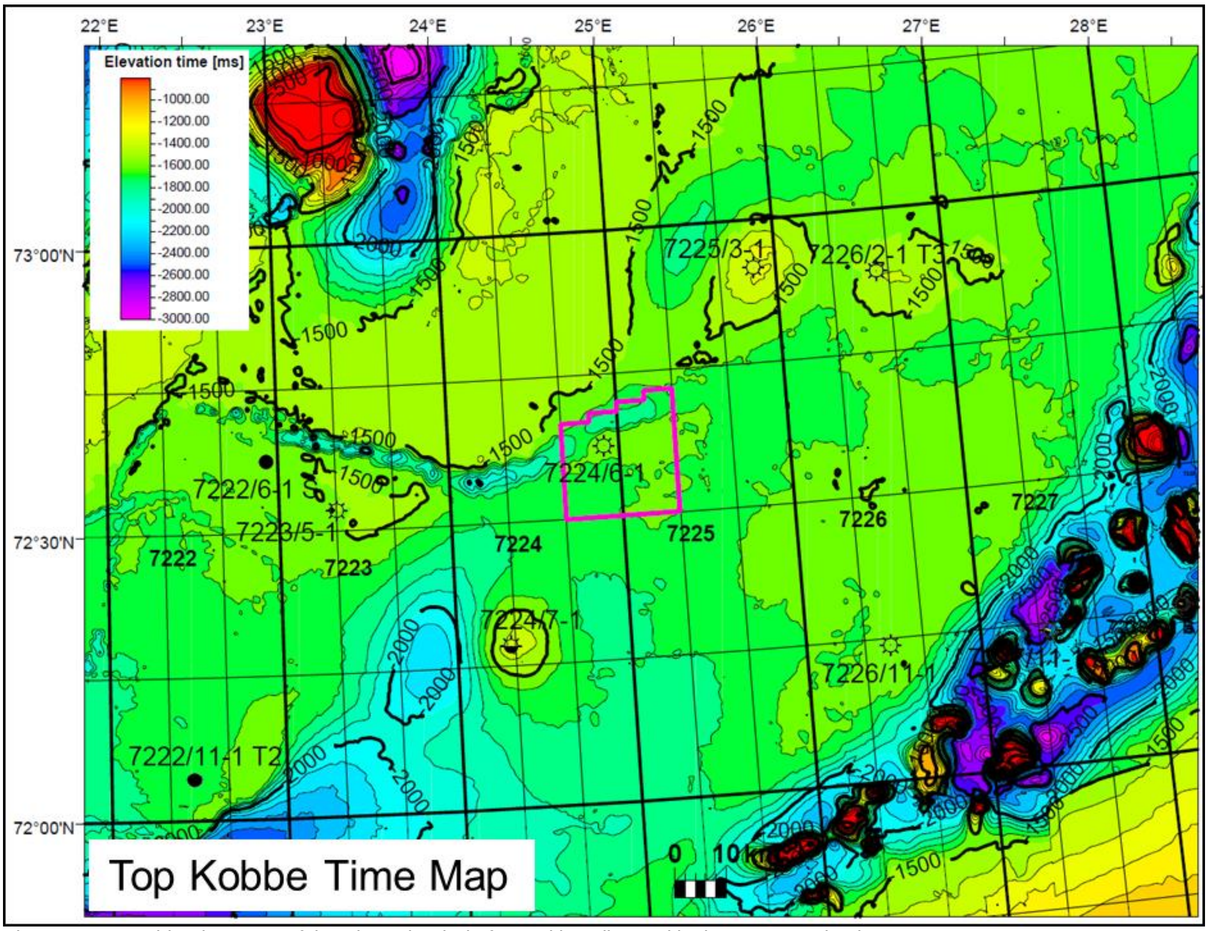


Figure 7: Top Kobbe time map of the Bjarmeland Platform with wells used in the common database.

3 Evaluation of remaining prospectivity.

Work done	Suplier	Reason/Content
Reprocessing of NH0608 and 200km of NBR 2D lines.	ION	Reprocessing was done for optimizeing seismic resolituion and imaging of the Kobbe Interval. Focus on imaging the thin Kobbe channels .
Seismic interpretation	In house	Interpretation and evaluation of the reprocessed seismic data.
Prospect evaluation.	In house	Incorporation of the results from the Norvarg 2 and Langlitinden wells into the evaluation for the Kobbe reservoir. Evaluation of Permian prospectivity.

3.1 Evaluation of the Kobbe Formation

Well 7224/6-1, drilled by Statoil in 2008, tested the prospectivity of the Jurassic Realgrunnen Group and the Triassic Snadd and Kobbe Formations. Realgrunnen Group and the Snadd Formation were found to be water bearing. In the Kobbe Formation the well proved gas in tight reservoir at four different levels (Figure 5). Driven by the encouraging results from well 7225/3-1, focus of exploration was on the Kobbe Formation and to a lesser degree on the Permian Carbonates of the Bjarmeland Group. Major prospect risk for the Kobbe Formation was reservoir quality.

NH0608DNR14 was reinterpreted, and main channels mapped out by the use of RMS amplitude and Frequency blending techniques. The reprocessed seismic data showed no major change in depositional and channel pattern. A seismic section trough the structure with the interpreted horizons is given in Figure 8.

The understanding of the reservoir quality and depositional system of the Kobbe Formation is highly dependent on the results from wells 7225/3-2 (Norvarg-2) and well 7222/11-2 (Langlitinden). Both these wells targeted untested channel facies observed from seismic.

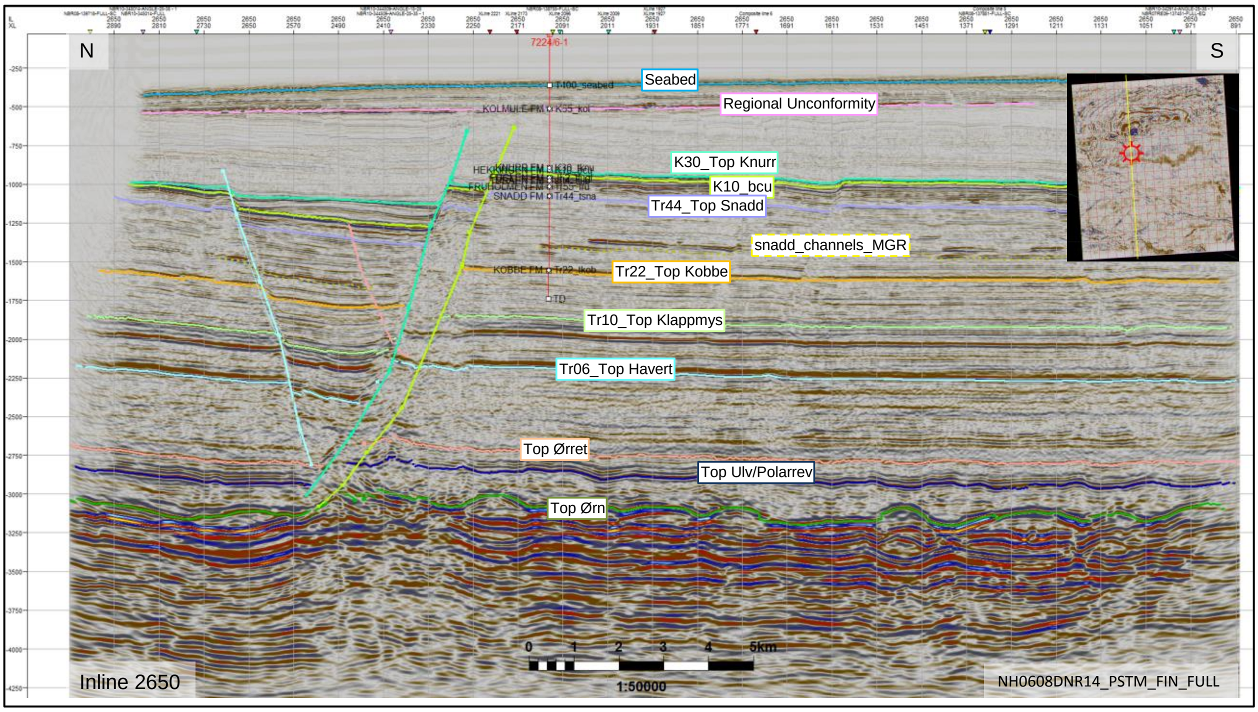


Figure 8: North-South seismic section trough the arenaria well.(NH0608DNR14).

3.1.1 Main well results, 7225/3-2 (Norvarg 2)

Figure 9 and Figure 10 shows CPI plots through the Kobbe reservoir levels, showing several gas-filled channels. 2 DST's were run in the well. DST#1 tested a 207m gross interval (1725mMD to 1932mMD) of which 55m was considered as Net reservoir. The test produced 28500 Sm^3 gas/day through a 40/64'' choke. DST#2 tested a gross interval of 23m, where 18m was consider net reservoir. The test produced 167400 Sm^3 gas/day through a 36/64'' choke. Both tests produced far poorer than expected, and based on pre-well estimates a production rate above 500 000 Sm^3/day was needed for commercial rates.

Reservoir properties in the channel facies of the Kobbe Formation was much poorer than expected. The dominant grain size in the channels were very fine to fine sand and included up to 50% of authigenic clay minerals, hence the porosities were ok but the permeability very poor.

The interpretation of the depositional environment after Norvarg-2 was that it was one of a very low energy, large low lying coastal plain/swamp areas with low energy tidal channels originating from the Uralides. Main deposition consisted of very fine to fine sands in the channels and silt/mudstones outside channels.

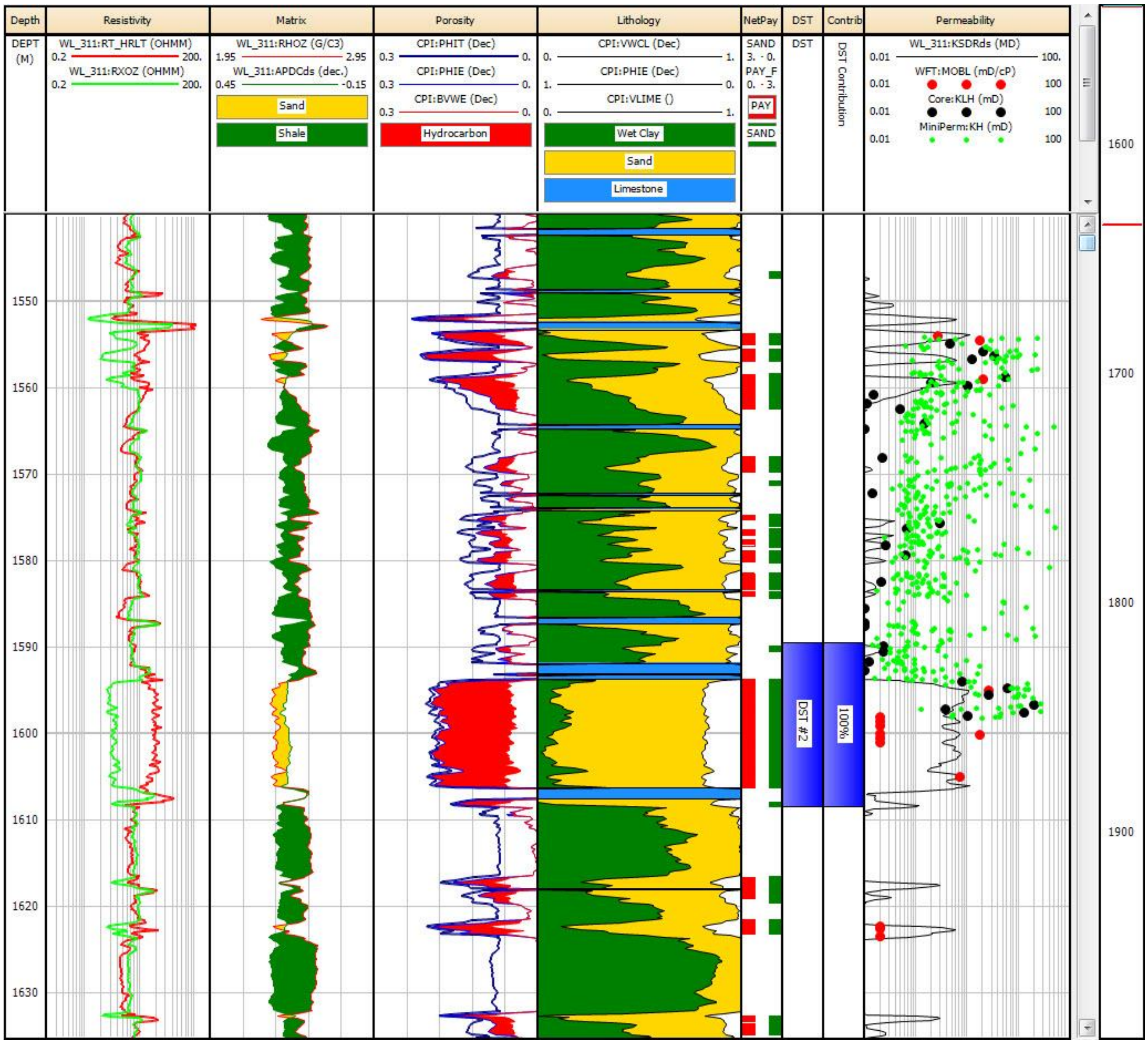


Figure 9: CPI plot from the 7225/3-2 well (Norvarg 2) including the DST 2 interval.

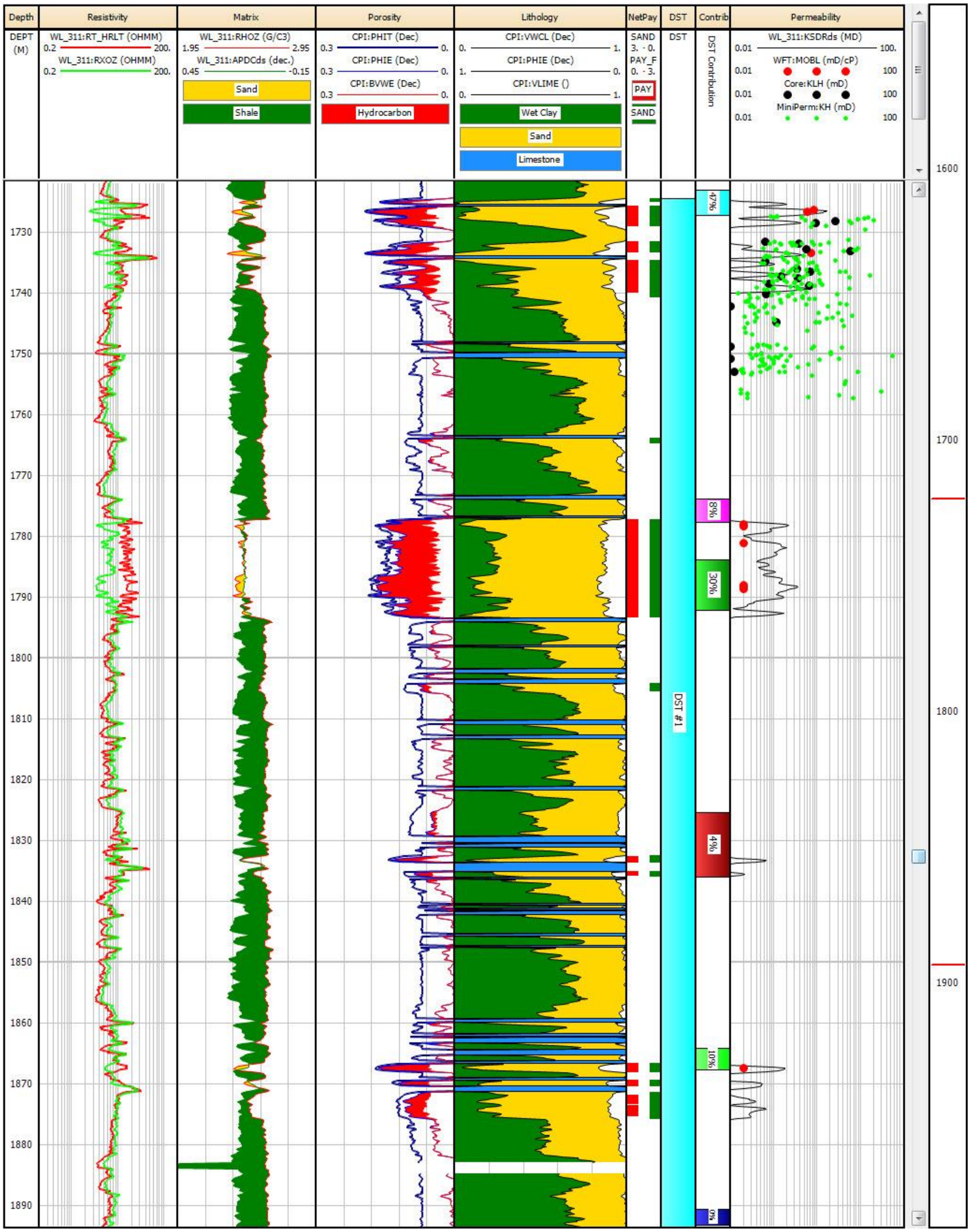


Figure 10: CPI plot from the 7225/3-2 well (Norvarg 2) including the DST 1 interval.

3.1.2 Main well results, 7222/11-2

Figure 11 shows a CPI plot through the Langlitinden channel, Kobbe Formation, in license PL659. The well proved oil in tight reservoir. The sedimentological interpretation of this well fits with that of the Norvarg wells, both mineralogical and sedimentological. The core from the Langlitinden channel shows very fine to fine grained sandstone with a high degree of authingenic clay minerals, supporting the model that the sediments came from the Uralides.

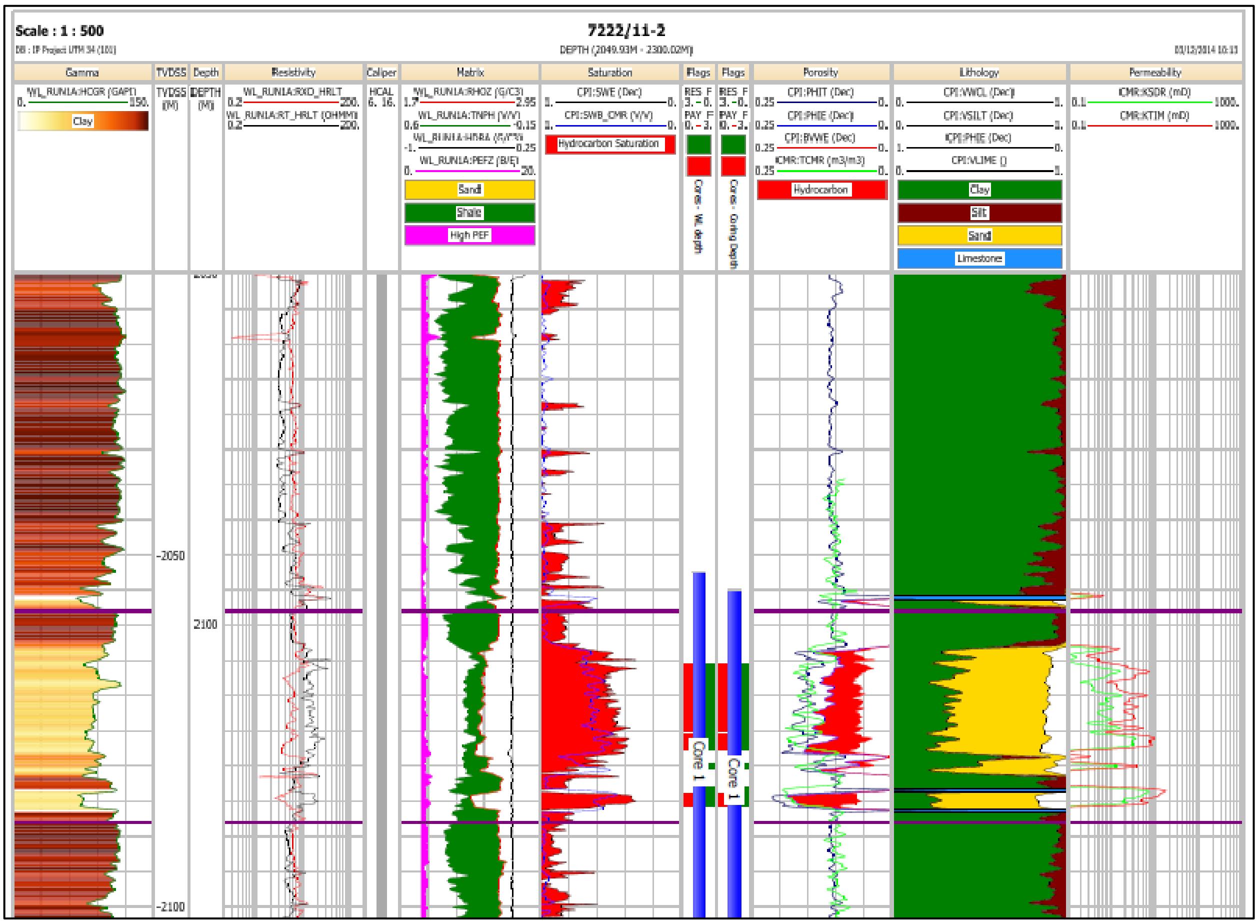


Figure 11: CPI plot trough the Langlitindenen channel, well 7222/11-2.

3.1.3 Arenaria evaluation after Norvarg-2 and Langlitinden.

Based on the results from 7225/3-2 and 7222/11-2, the Arenaria prospect (main prospect in the license) was heavily downgraded. Prospect area was reduced from a large 3-way dip closure of 493 km^2 down to only include the main channel seen from the seismic, making it a purely stratigraphic trap of 95 km^2 (Figure 12). Reservoir thickness was based on the channel thicknesses from Norvarg and Svanefjell. Risk factors and volume input parameters are given in table Table 4 and Table 5. Mean in-place volumes after re-evaluation are estimated to 25.3 GSm^3 gas (Figure 13), with mean recoverable volumes of 7.1 GSm^3 gas (Figure 14).

Play	1
Reservoir presence	1
Reservoir quality	0.8
Trap geometry	0.7
Source presence	1
Migration and Timing	1
Total chance of success	**0.56**

Table 4: Risk table

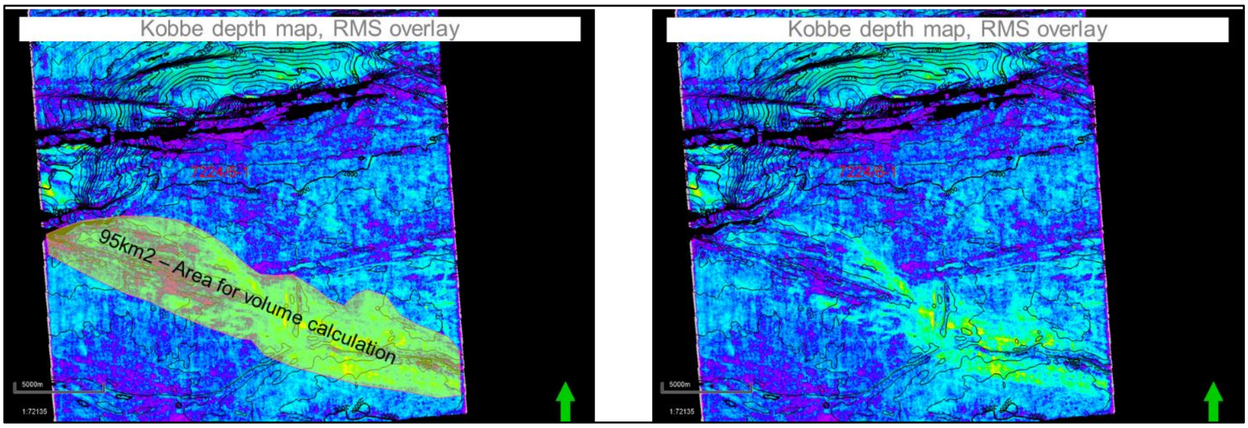
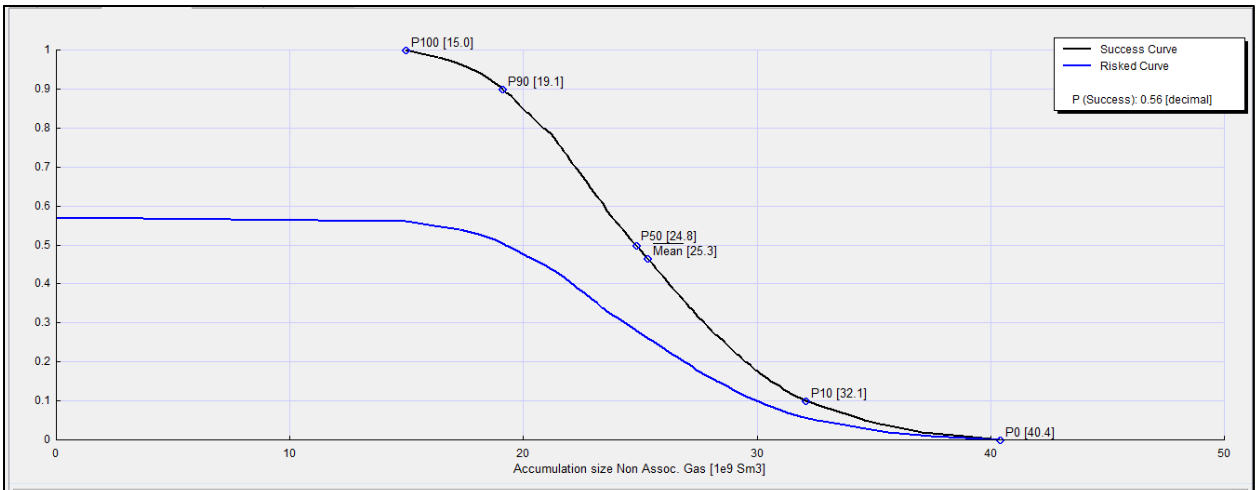


Figure 12 : Kobbe depth map with RMS overlay. Right picture shows the channel for the volume estimates. Left picture shows the area outline used.

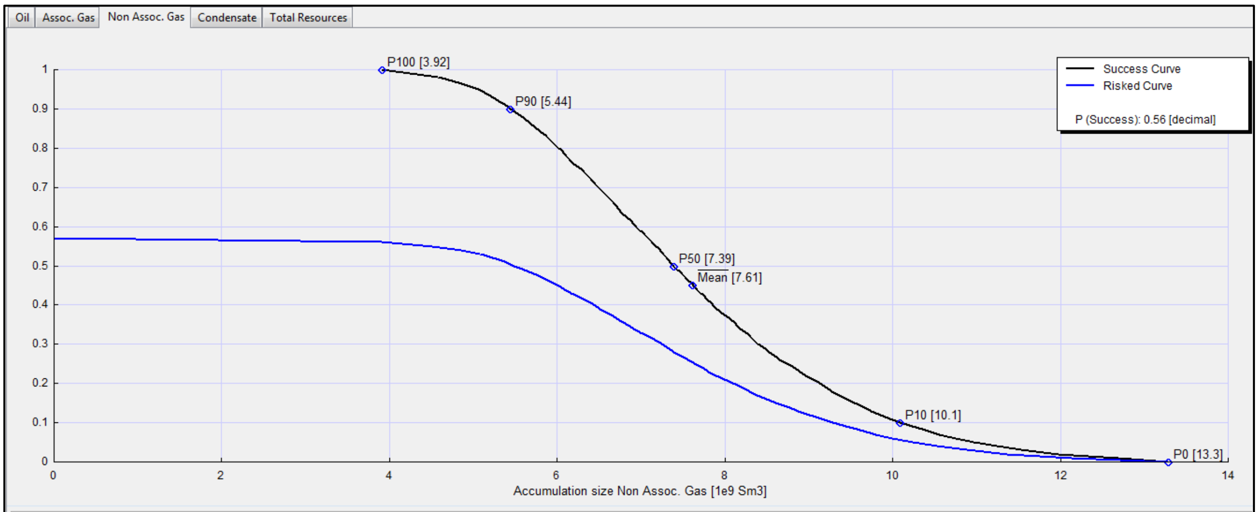
Parameter	***Min (Lo)***	***Mean***	***Max (Hi)***
Area (km^2)		95	
Reservoir thickness (m)	15	20	30
N/G	0.5	0.6	0.7
Porosity	0.12	0.15	0.18
Gas saturation	0.5	0.65	0.7
1/Bg	203	213	224
Condensate yield	30	40	50
Rec. factor Gas	0.2	0.3	0.4
Rec. factor condensate	0.2	0.3	0.4

Table 5: Volume parameter input table



Scenarios	Dist. type	Mode	Mean	Std. dev.	P100	P90	P50	P10	P0	Overall proba...
Failure										0.440
Success volume	MC(5000)	23.0	25.3	5.12	15.0	19.1	24.8	32.1	40.4	0.560
Unconditional segment	MC(5000)-r		14.2	13.1	0.0	0.0	19.2	30.0	40.4	1.000

Figure 13: Success curve and estimated In-place volumes.



Scenarios	Dist. type	Mode	Mean	Std. dev.	P100	P90	P50	P10	P0	Overall proba...
Failure										0.440
Success volume	MC(5000)	6.94	7.61	1.83	3.92	5.44	7.39	10.1	13.3	0.560
Unconditional segment	MC(5000)-r		4.26	4.02	0.0	0.0	5.48	9.29	13.3	1.000

Figure 14: Success curve and estimated recoverable volumes.

3.2 Evaluation of the Permian Carbonates

In light of the encouraging results from the Permian discoveries on the Loppa High, an evaluation of the Permian was carried out. The play is not identified by NPD in the license area (Figure 15), but several buildups belonging to the Bjarmeland and Gipsdalen Groups (Figure 16) were observed from seismic.

	bcu,pl-3 (unconfirmed)	bcu,pp-4 (unconfirmed)
Group/ Formation	Gipsdalen Group with Falk and Ørn Formations	
Age	Late Bashkirian-Late Sakmarian	
Area	Finnmark Platform	
Reservoir	Limestones and dolomites	Sandstone
Depostional environment	Carbonate buildups in shallow marine, warm water	Mostly marginal to shallow marine, alluvial and fluvial inputs in the Carboniferous
Trap	Stratigraphic, but a combination of stratigraphic and structural cannot be excluded	
Source rock	Upper Devonian-Lower Carboniferous shales, Lower Carboniferous coal (Billefjorden Group), Upper Permian shales (Tempelfjorden Group), Middle Triassic shales (Steinkobbe Formation). (Tempelfjorden Group).	
Critical factors	Presence of mature source rock. Reservoir quality. The area has been affected by tilting, reactivation of faults, and Cenozoic uplift and erosion.	
Link to examples of wildcat wells	7128/4-1 7128/6-1 7120/12-2 7120/12-4 (7128/4-1 7128/6-1 7120/12-2 7120/12-4)	

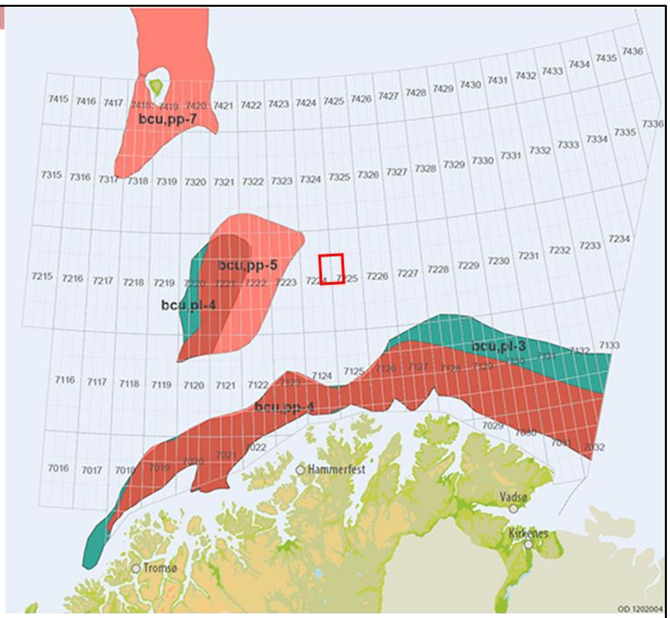


Figure 15: NPD Permian play map

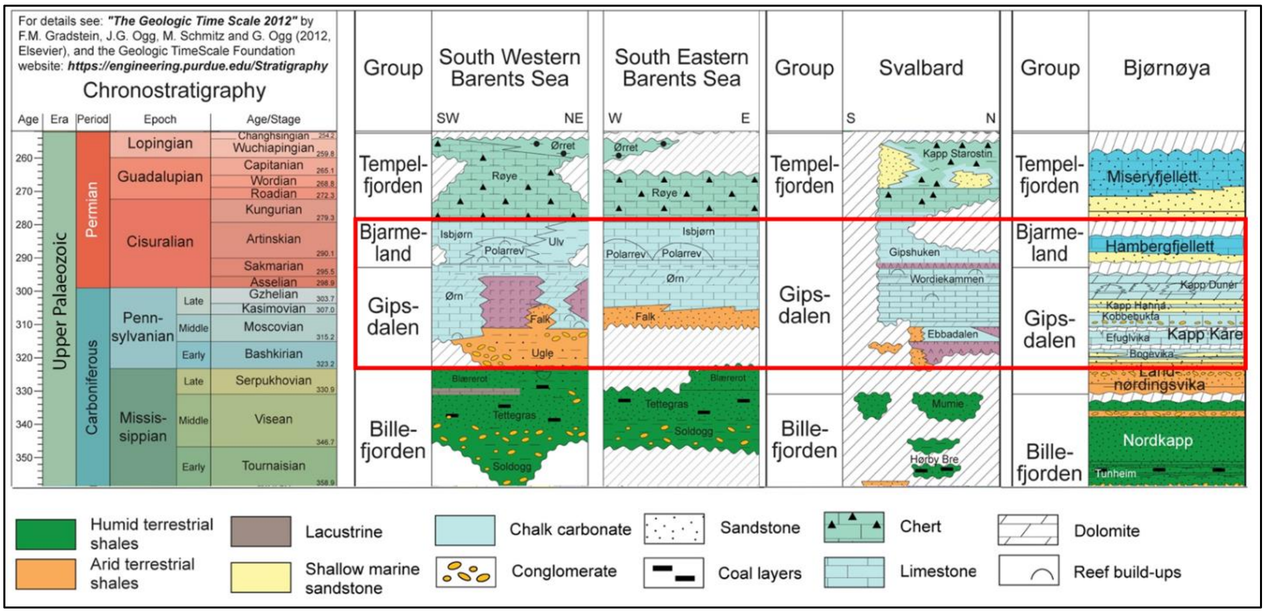


Figure 16: Permian chrono and lithostratigraphy (Gradstein et. al. 2012)

A surface following the top of the buildups was interpreted, and potential closures were mapped out (Figure 17 and Figure 18). No large closures were identified, but some smaller closures associated with the South bounding fault of the Swaan Graben was identified. Taken into account the net erosion in the area the maximum burial depth of these carbonates was estimated to approximately 6000m. Based on work done by Schmoker and Halley (1982) (Figure 19), and results from other deep wells in the Barents Sea, such as 7226/11-1 (Figure 17), it was concluded that the Permian build ups were unprospective, and believed to be tight.

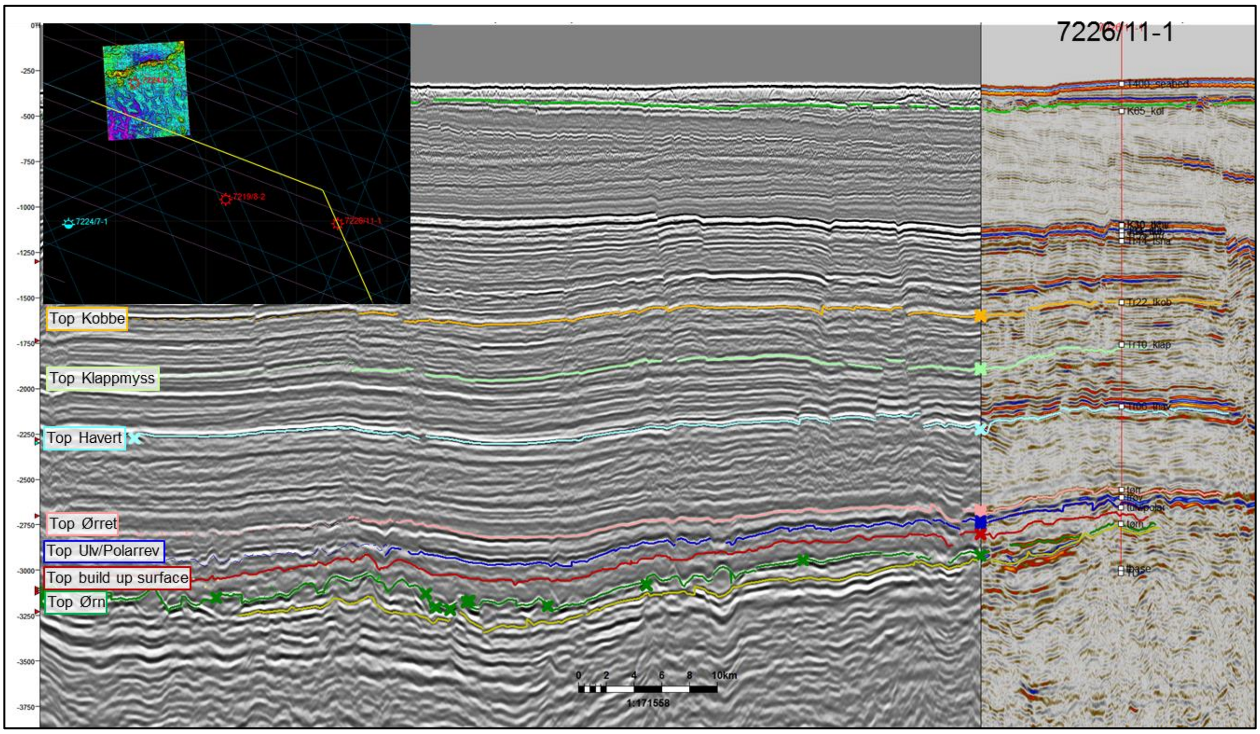


Figure 17: Seismic tie line from well 7226/11-1 into the NH00604DNR14 survey.

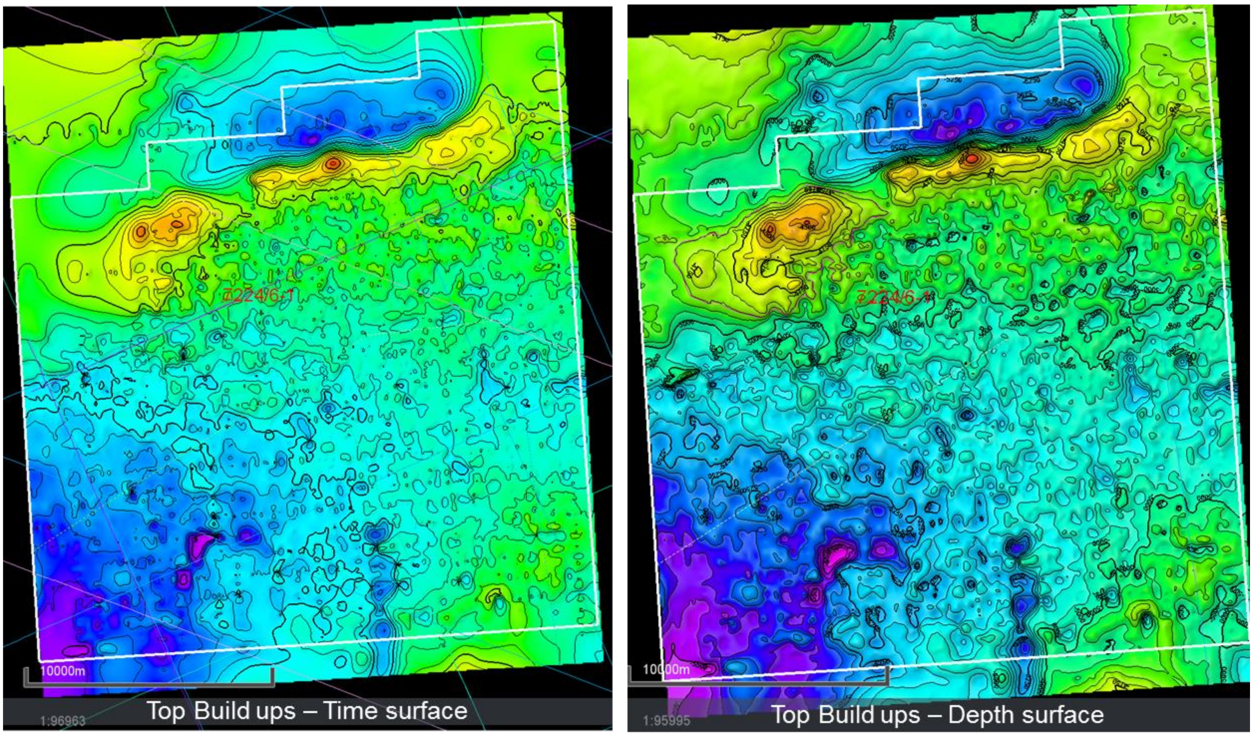


Figure 18: Time and depth maps of the top of the Permian buildups.

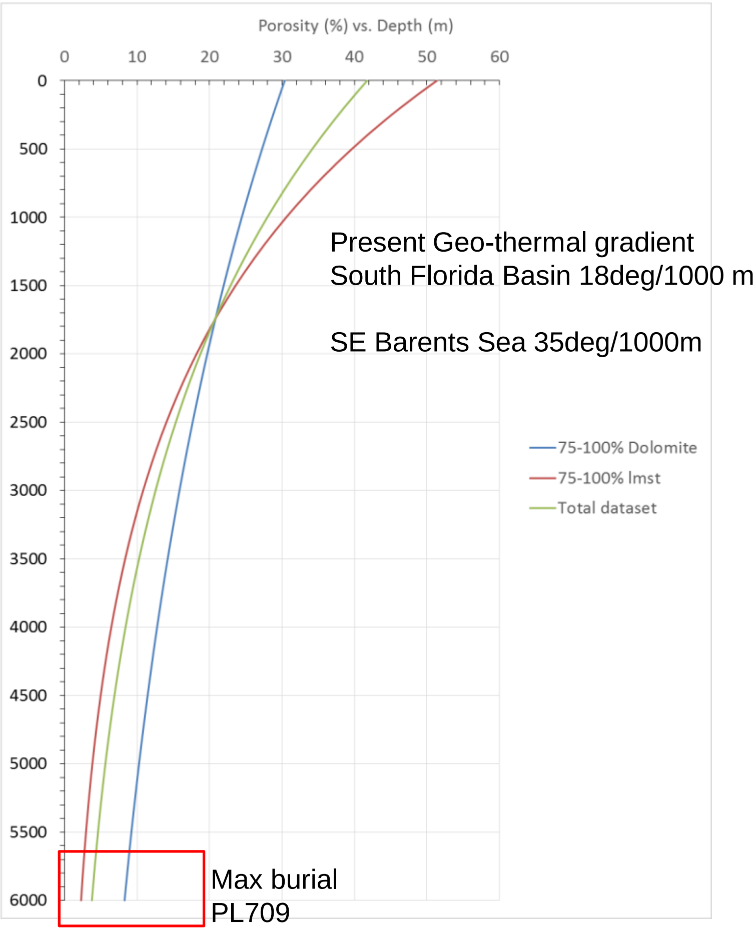


Figure 19 : Porosity vs Depth for dolomite and limestone (Schmocker and Halley, 1982)

4 Conclusion

Based on the work done in the license, it was concluded that the prospectivity was limited. The well 7224/6-1 tested all potential prospective levels. The remaining potential in the area is related to the Kobbe Fm, and is found very limited and not economical.

The decision for relinquishment of the license were unanimous, and the license was officially relinquished on 21.06.2016.

5 References

- Carbonate Porosity Versus Depth: A Predictable Relation for South Florida[1]
  James W. Schmoker and Robert B. Halley[2]
  American Association of Petroleum Geologists Bulletin V.66, No. 12 (December 1982)

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- The Geological Time Scale 2012
  F.M Gradstein, J.G. Ogg, M. Schmitz and G. Ogg
  The Geological TimeScale Foundation website: *https://engineering.purdue.edu/Stratigraphy*