PL 425S

Relinquishment Report

Blocks 33/3 (part) and

34/1 (part), 2 (part), 4 (part)

PETRO-CANADA

wintershall

BASF Group

PL 425S Relinquishment Report

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Summary and Conclusions

This report documents the results of the prospectivity evaluation carried out by Petro-Canada Norge AS and its partner Revus Energy ASA (now Wintershall Norge ASA) in Production License 425S during the period 2007 - 2008. This evaluation included the acquisition, purchase, reprocessing and interpretation of 2D and 3D seismic data, as well as of special geological and geophysical studies.

The PL 425S group has fulfilled its obligations attached to the first License term.

A relatively large prospect has been identified within PL 425S but it is considered to have very high risk of failure. Consequently, co-venturers have agreed to relinquish this acreage effective 16th February, 2009.

Introduction

Production License 425S was awarded to Petro-Canada Norge AS (Operator) and Revus Energy ASA (Partner) on the 16th of February 2007. The acreage is located in the northern part of the North Sea, Figure 1. In accordance with the License Agreement, the PL 425S co-venturers have agreed to relinquish the acreage on 16th February 2009 and will not enter a second license term.

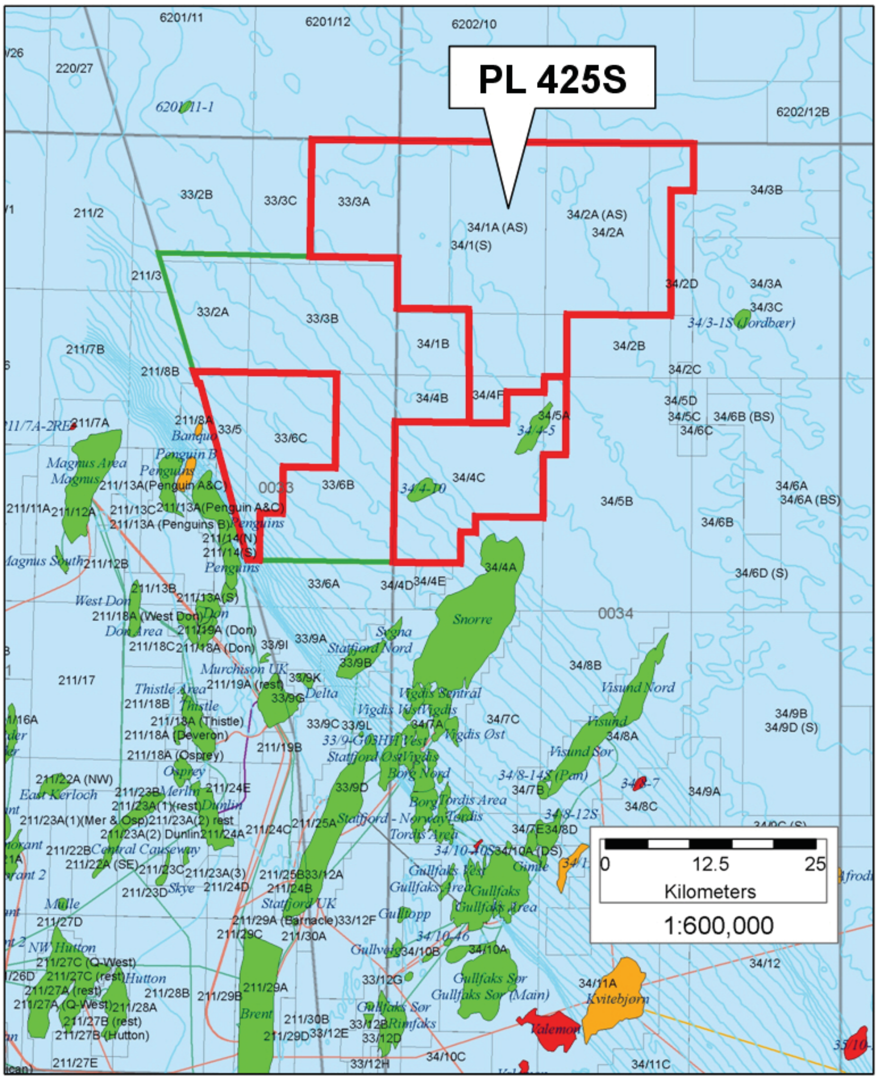


Figure 1 PL 425S Location Map.

A potentially atttractive Lead called Lagen was recognised during the 2006 APA Round evaluation. This lead was defined within the Paleocene section (Chapter 3). Presence of viable sandstone reservoirs and prospect definition were recognised as the major uncertainties.

To address the uncertainties, the PL 425S Group has acquired 3D seismic data, according to the original Work Commitment. In addition, selected 2D seismic data have also been purchased and reprocessed to improve the evaluation of the identified opportunities.

An extensive geological and geophysical evaluation of the prospectivity, involving several special studies, has been carried out. A large prospect has been confirmed in the acreage but this has high risk of failure which makes it unsuitable for commercial exploration.

1 License Terms and Conditions, Work Programme

License :	PL 425S
Block(s) :	33/3 (part), 34/1 (part), 34/2 (part) and 34/4 (part)
Location :	Marulk Basin
Operator :	Petro-Canada Norge AS (60%)
Co-venturers :	Revus Energy ASA (now Wintershall Norge ASA) (40%)
Date Awarded :	16/02/2007
Relinquishments :	2+2+1 years
Expiry Date :	16/02/2012
Area :	950.6 km^2
Work Commitment :	Purchase or acquire 3D seismic within the awarded acreage.
JOA voting Passmark :	50% (2 parties)

The work commitment consisted of acquiring and/or purchasing of 3D seismic data over the awarded acreage to evaluate the prospectivity of the Paleocene section. This commitment has been fulfilled and approved by the Norwegian Petroleum Directorate on 10th October 2008 (ref. OD07/481/MSe/JS).

2 Geological and Geophysical Database

Table 2.1: Common Well Database

NO33/5-1 *) **)	NO34/4-3	UK210/10-1	UK211/11-1
NO33/5-2 *)	NO34/4-5 *)	UK210/13-1 **)	UK211/12-1
NO33/6-2	NO34/4-8	UK210/14-2RE	UK211/12-2
NO33/9-10	NO34/7-18	UK210/15B-4	UK211/12-5
NO33/9-4	NO34/7-21	UK211/07-1	UK211/12-6
NO34/2-2R *) **)	NO34/7-21A	UK211/07-2 **)	UK211/12-7
NO34/2-3 *)	NO34/7-29	UK211/07-4	UK211/13-1
NO34/2-4 *)	NO6201/11-1 *) **)	UK211/08-1	UK211/13-2
NO34/4-10R	NO6201/11-2 *)	UK211/08A-2	UK211/14-4
NO34/4-2	NO6204/11-1 **)	UK211/08B-3	UK211/18A-23

*) Key wells for seismic calibration, see also Chapter 4.1.
**) Key wells used for geological correlation.

Table 2.2 Common Seismic Database.

	Survey	**General Info**	**Data Quality**
3D	pc07n23 (full, far and near offset)	Acquired by Petro-Canada Norge AS in 2007	Medium - Good
	MC3D-Q34-1,2,3	Acquired by PGS in 1996. Released early 2008.	Good
2D	GMA-92	Lines GMA-92-407, GMA-92-408, GMA-92-409, GMA-92-410, GMA-92-411, GMA-92-412, GMA-92-413, GMA-92-414a, GMA-92-415, GMA-92-416, GMA-92-213, GMA-92-214, GMA-92-215, GMA-92-216, GMA-92-217	Medium
	WG-Reproc_GMA92	Reprocessed by WesternGeco for Petro-Canada in 2008; Lines GMA92-401, GMA92-408, GMA92-412, GMA92-414, GMA92-416, GMA92-208, GMA92-209, GMA92-210, GMA92-211, GMA92-212, GMA92-213, GMA92-214, GMA_TW301	Good
	TNW-92		Medium
	MN9104	Regional lines	Medium
	MN9105	Regional lines	Poor

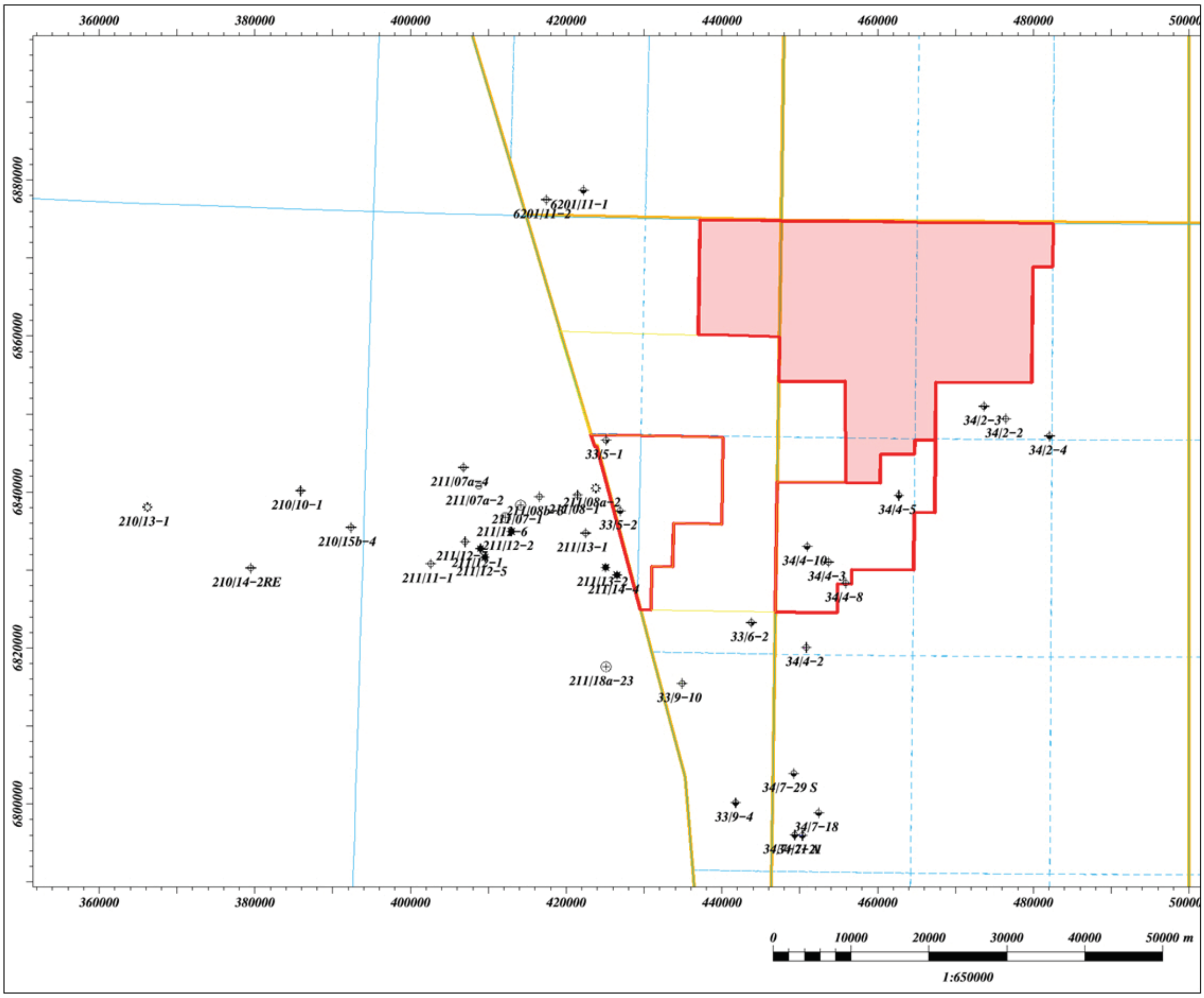


Figure 2.1 Common Well Database. PL 425S is the filled red polygon.

The acquisition of the 3D Survey pc07n023 was the main operation within this license (Figure 2.2), according to the initial work obligation. This survey was intended to cover the previously recognised Paleocene prospectivity and designed for that purpose. The area covered by pc07n23 is 663 km^2. Bad weather during acquisition resulted in an uncomplete execution of the original plan. However, the area covered by this survey is deemed by the partners as well as by the NPD to fulfill the work obligation, as being documented in the correspondence, Petro-Canada ref. 0104 and NPD ref. OD07/481/MSe/JS (Chapter1).

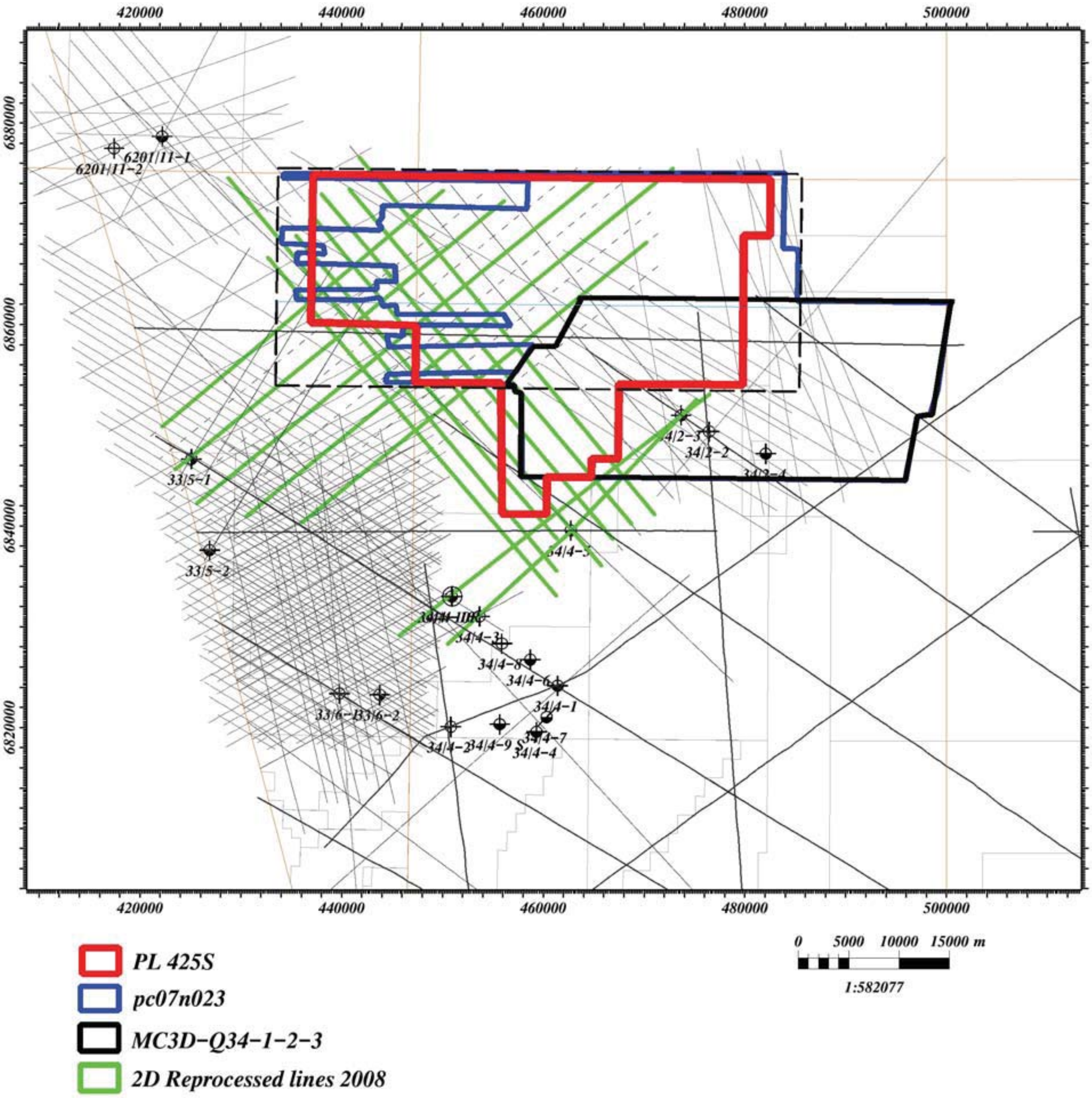


Figure 2.2 Common Seismic Database. 2D seismic lines in green colour are those reprocessed by the PL 425S partnership in 2008.

3 Geological Evaluation

3.1 Regional Structural Framework and Petroleum Occurence

PL 425S is located in the Marulk Basin, a northeast to southwest elongated extensional basin that mostly developed during the Late Jurassic to Early Cretaceous rift phase in the North Sea. This basin is bounded by the Snorre/Zeta Ridge (Tampen Spur) to the southeast, the Manet Ridge to the northwest and by the Penguin Ridge to the west (Figure 3.1).

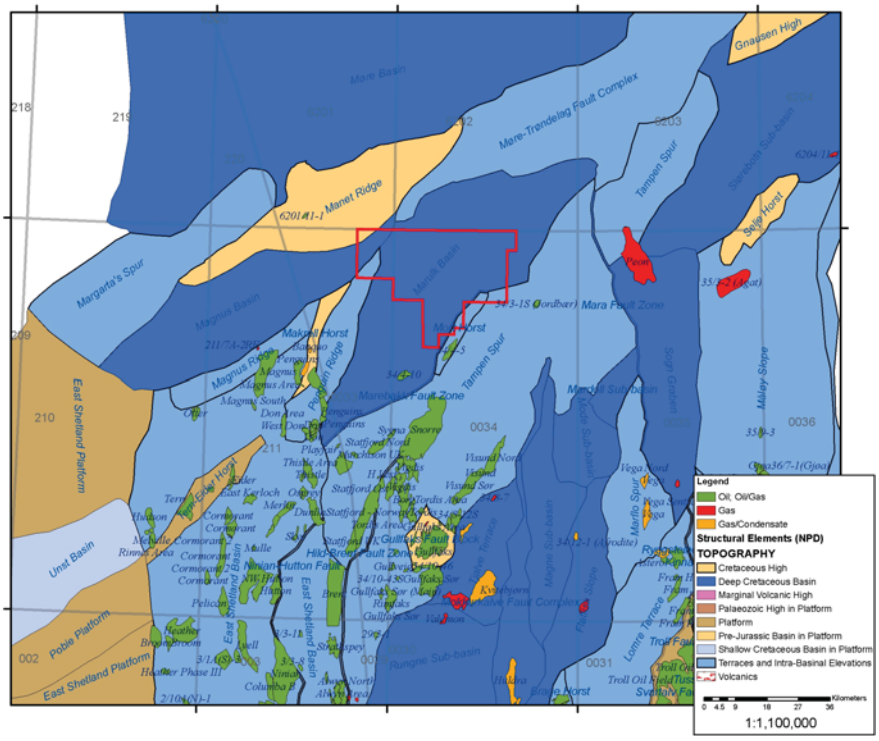


Figure 3.1 PL 425S Location and Structural Elements Map. Source: the NPD.

The Marulk Basin is under-explored to date, despite being close to a major petroleum province containing the giant Norwegian Snorre and Statfjord fields as well as the Magnus Field in the UK sector. Near PL 425S, some oil discoveries occur within the basin itself (Wells 34/4-10R and 34/4-5) and on Tampen Spur (Well 34/3-1S) in Jurassic reservoirs.

3.2 Stratigraphical and Sedimentological Framework

The Marulk Basin stratigraphic record comprises a Triassic to Quaternary succession (Figure 3.2), as a result of extensional episodes and subsidence since Permian times.

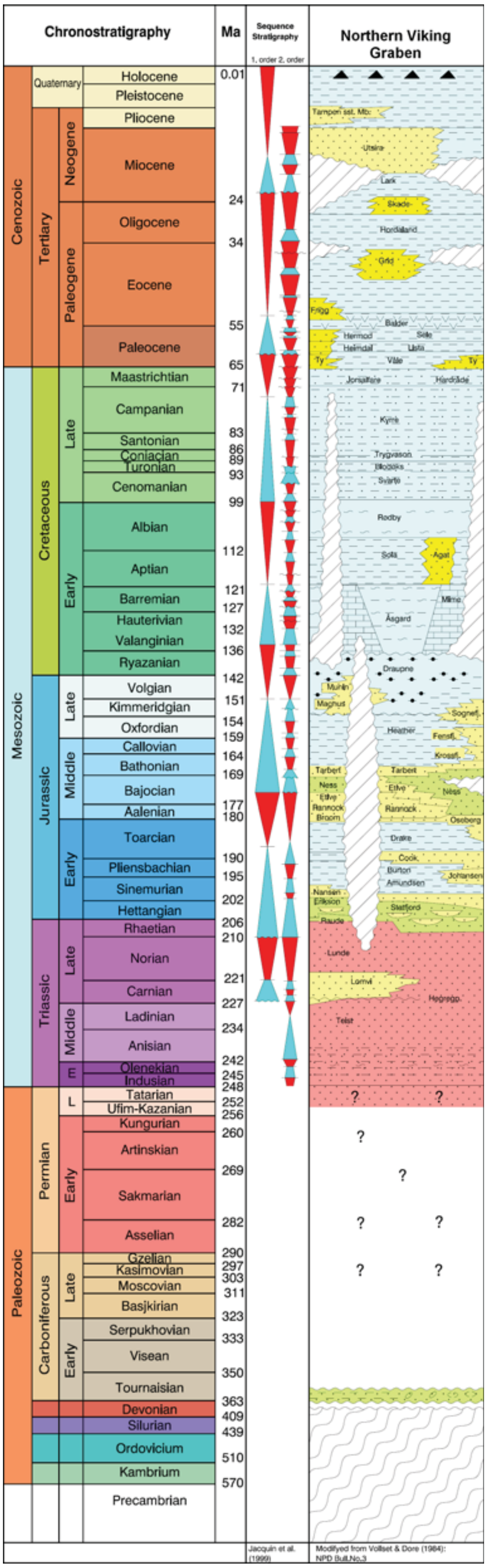


Figure 3.2 Stratigraphic Column, Northern Viking Graben.

Thick pre-rift Triassic and Jurassic continental- and shallow marine sediments represent the earliest basin infill penetrated by wells. A final sequence of fluvio-deltaic to shallow-marine sediments (Brent Group) concluded this pre-rift phase. This sequence contains the reservoirs which represent one of the most successful plays in the North Sea.

During the Late Jurassic, the region experienced a major tectonic extension. This activity resulted in footwall collapse and the subsidence of rotated blocks in the basinal areas. Marine, sometimes organic rich, shales were also deposited in anoxic conditions within half-grabens (Viking Group). These shales, particularly the Draupne Formation, represent the most important source rock unit in the area, from which most of the known accumulations in the Norwegian North Sea are derived.

The structural highs created during this rift phase, such as the Snorre High and the Manet and Penguin Ridges, locally acted as sediment sources for sandy deposits within the syn-rift units. These highs continued to shed sediment during the Cretaceous phase of post-rift subsidence. These sediments are mostly shale with limestones, but sometimes contain of coarse, submarine fan-apron deposits with gravity flow sandstones, as penetrated in the UK sector by well 210/10-1. The highs eventually became fully submerged during the Late Cretaceous, when shales with some limestones of the Shetland Group were deposited.

During Late Cretaceous and Early Tertiary times, the areas to the west of the Marulk basin experienced thermal uplift as the North Atlantic began to open. This resulted in erosion on the western edges of the European plate and the deposition of coarse clastics into the basinal areas of the North Sea. These clastics represent another successful play in the North Sea (e.g. Heimdal, Balder, Jotun Fields).

In the Marulk Basin and the immediately surrounding areas, evidence from wells indicate that prevailing thermal subsidence conditions persisted during the Early Tertiary. This type of subsidence mostly resulted in the deposition of Rogaland Group shales. Sandstones have been found further north in the Tulipan and Ormen Lange discoveries. The presence of coeval coarser clastics (i.e. viable exploration targets) within the Paleocene section in PL 425S represents one the major exploration challenges.

The following and final basin infill phase (Eocene - Quaternary) resulted in the deposition of shaly deposits (Hordaland and Nordland Groups), with sandstone units in the Eocene, Miocene (Utsira Formation), Pliocene and Quaternary.

3.3 Petroleum Systems and Play Models

This evaluation focuses on the Paleocene sandstone play. This play consists of marine gravity flow sands, charged from the Upper Jurassic Draupne Formation source rock and sealed by Upper Paleocene shales (Figure 3.3).

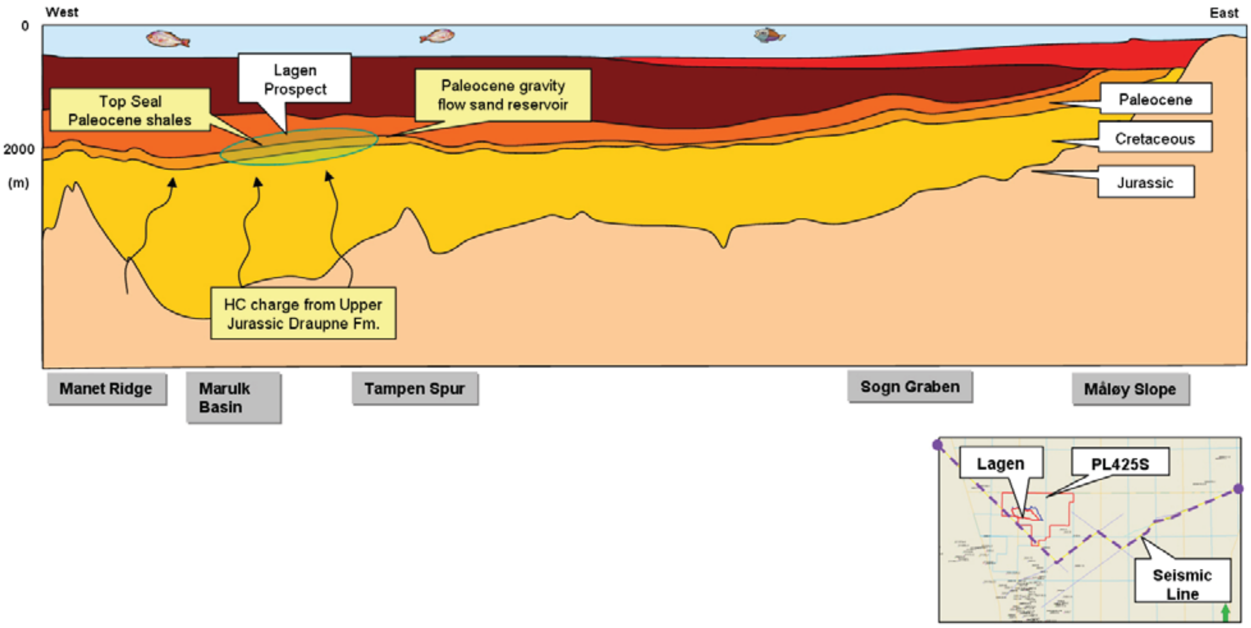


Figure 3.3 Geosection across the Study Area and Paleocene Sand Play Model. Geosection based on interpreted 2D seismic lines, illustrating the conceptual Play Model for the Lagen Prospect. Paleocene reservoir sandstones of the Lista and Sele formations are interpreted to be gravity flow deposits. Upper Paleocene units provide top seal facies. Hydrocarbon charge is from the Upper Jurassic Draupne Formation.

Other play models in the area are the Jurassic, the Cretaceous and the Pleistocene: these were however not considered because of a) depth of burial and b) original license terms (i.e., PL 425S applies to all levels below base Pliocene).

3.4 Sand Development during the Paleocene

Preliminary investigations during the APA 2006 evaluation suggested that seismic facies (hummocky, mounded facies) and thickness changes within the Paleocene section could indicate basin floor, gravity flow sandy facies.

A regional log correlation tying relevant wells in the area shows that some Lower Paleocene sands have been found on the UK side and close to the Norwegian mainland. However, no sands have been found in any of the PL 425S offset wells, Figure 3.4 and Figure 3.5.

The occurrence of potential Paleocene sandy reservoirs within the Marulk Basin should be seen in the context of its late Mesozoic - Cenozoic structural evolution, i.e. as part of the Møre Basin. From the end of Cretaceous times, this basin experienced a rapid subsidence with the deposition of prevailing shales. The surrounding emergent areas, such as the Scandinavian mainland and Proto-Greenland, experienced limited uplift and erosion and consequently limited development of coarser clastics. In addition, large platform areas which could initially trap these coarser

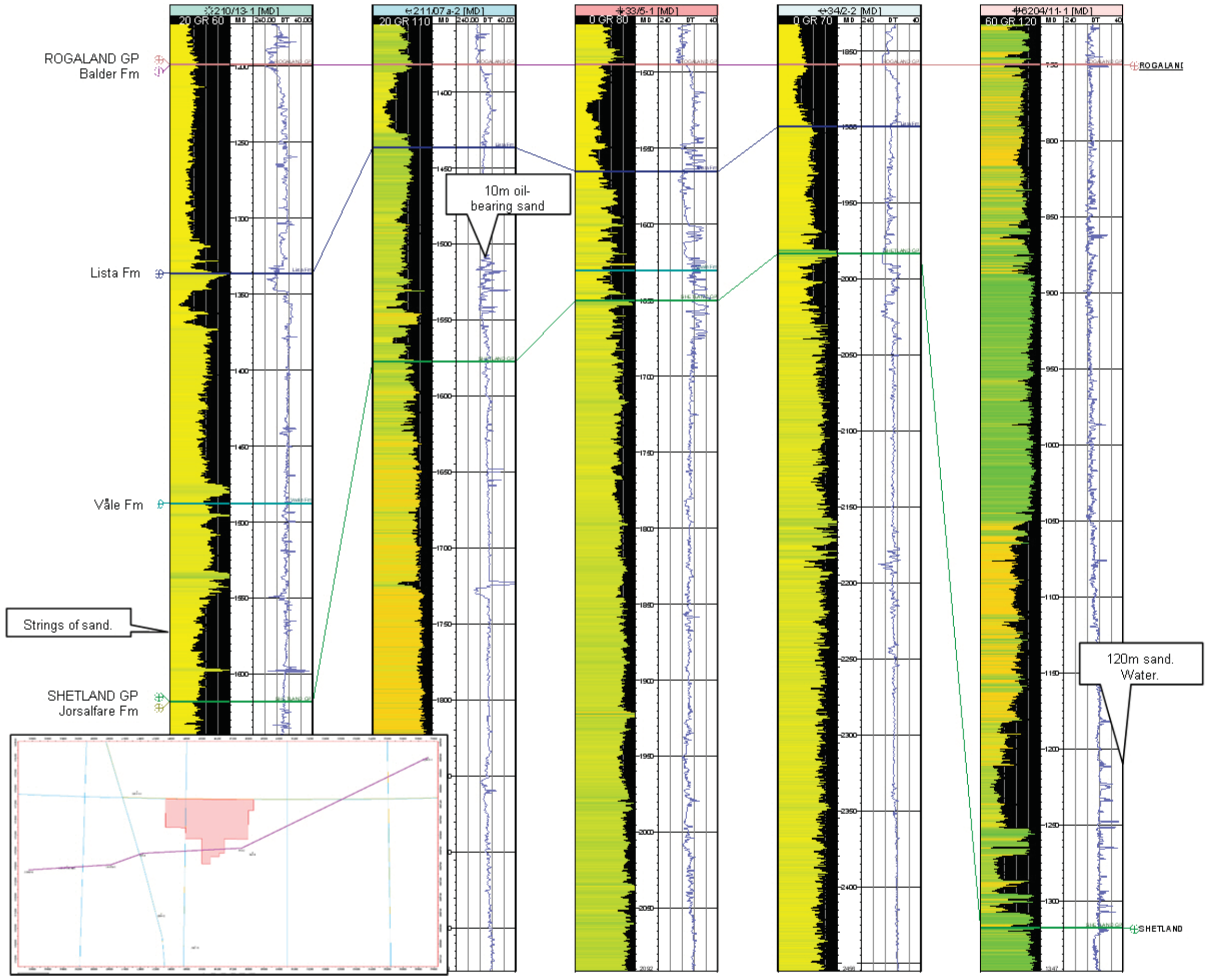


Figure 3.4 Regional Well Correlation. Paleocene sandstone reservoirs mainly occur in the lower part (Lista and Egga Formations) of the Paleocene section (Top Shetland to Top Rogaland). No such sands are found in the immediate offset wells to PL 425S. Also note the significant sandstone occurrence towards the east, where the overall thickness of the Paleocene section increases.

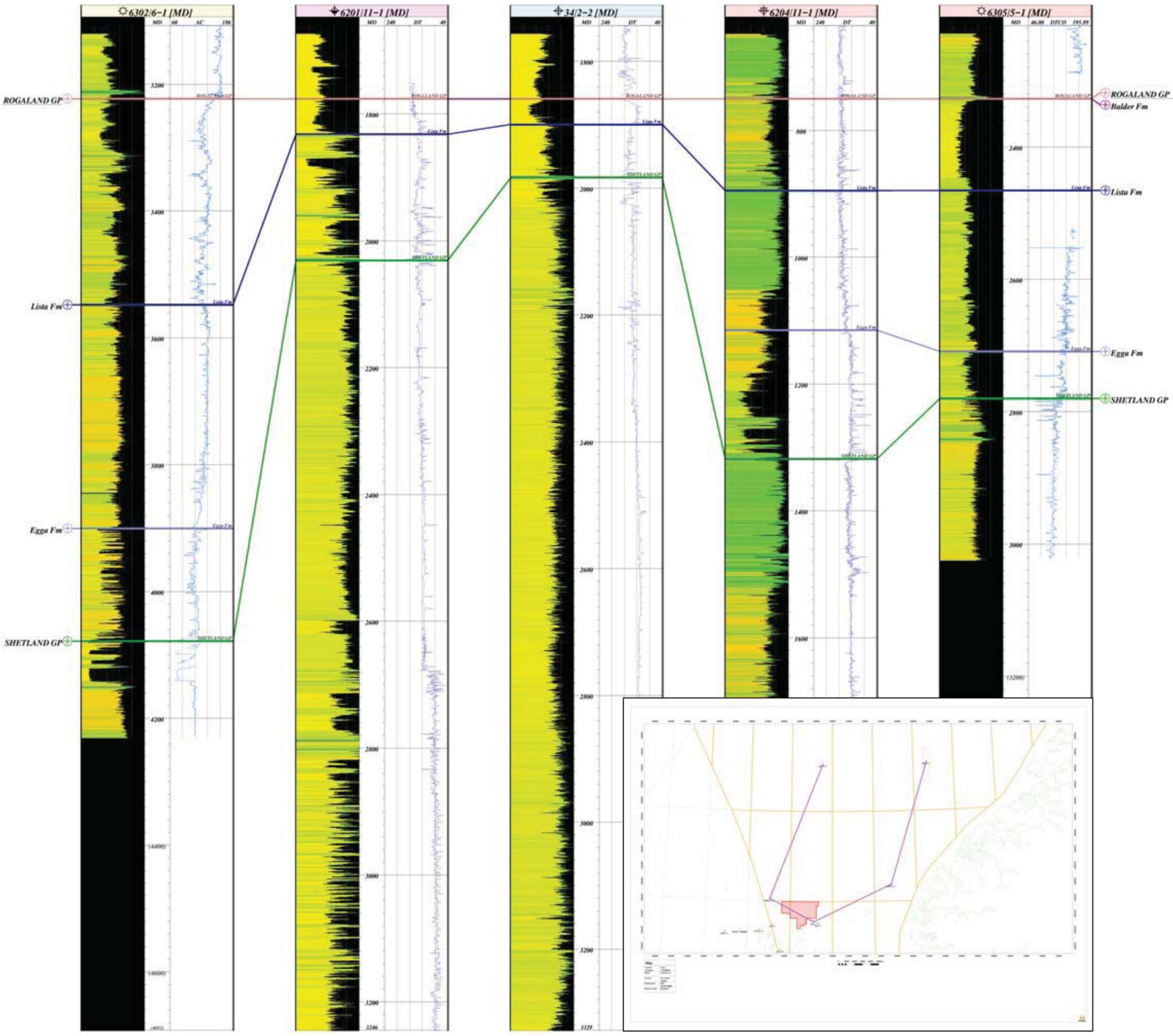


Figure 3.5 Regional Well Correlation. Sandstone reservoirs occur within the lower portion of the Paleocene section (Egga Formation) at the Ormen Lange Field to the east as well as at the Tulipan Discovery to the west. Note the overall thickness increase of the Paleocene sections where sandstone occur, in line to what observed in the North Sea. Nearby wells to PL 425S show a remarkably thinner Paleocene section, indicative of lower accommodation. Also, note the distance from Ormen Lange and Tulipan to PL 425S (approximatively 200 km): potential sands in PL 425S are unlikely to be part of the same depositional systems.

clastics did not develop around their basin margins. Consequently, those Paleocene sands found in the surrounding areas of PL 425S have to be be reviewed within this structural and depositional context, Figure 3.6.

In the Statfjord Area to the south, sandstones correlated with the Upper Paleocene Heimdal Formation were penetrated in a few exploration wells, and are interpreted as the distal facies of coarser clastic systems sourced from the East Shetland Platform.

Further to the east, Paleocene sandstones are encountered on the eastern margin of the Sogn Graben and northwards along the Møre Margin. These sands, corresponding to the Heimdal Formation, are best developed in the area of the Fram and Agat Fields, where they reach thicknesses of around 50 m. These sediments are not part of major submarine fan depositional systems such as those developed along the East Shetland Platform, but represent smaller and isolated debris-flow systems.

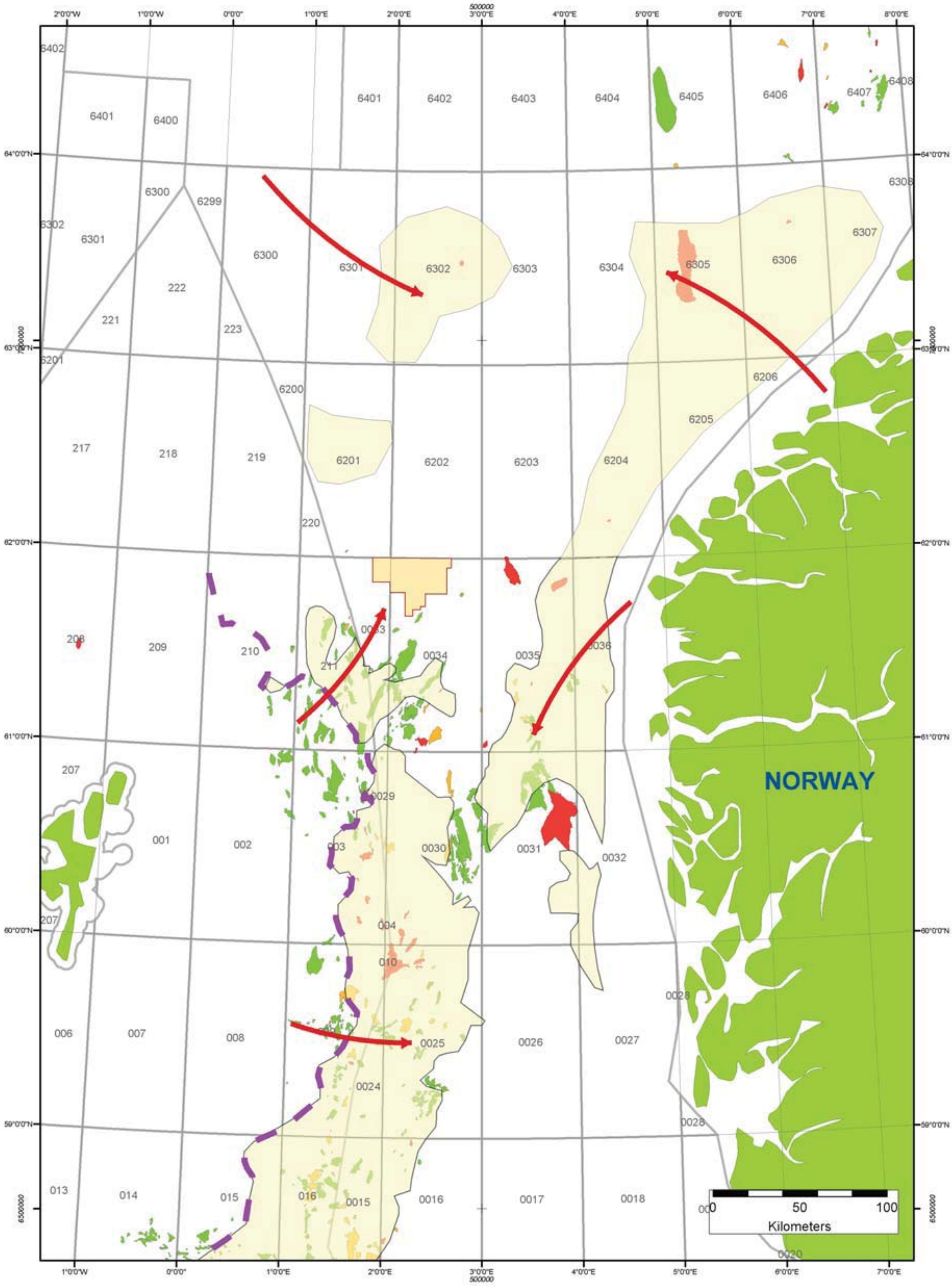


Figure 3.6 Paleocene Sand Distribution Map.

Shallow marine facies are reported from wells in the Slørebotn Basin, and further to the north, deep marine gravity flow deposits occur at the Ormen Lange Field in the Rås Basin. Thickness of these units varies between 80 m at Ormen Lange and 200 m in well 6204/11-1. The latter is the nearest (60 - 70 km away) and is the most important occurrence of Paleocene sands in relation to the PL 425S acreage.

Further to the northwest of PL 425S, Paleocene sands are found in the Møre Basin (Tulipan discovery), but probably these were sourced from the west (Proto-Greenland).

Overall, these sand occurrences are sporadic when considered on a regional scale. The overall depositional system in the Marulk/Møre basin area during Paleocene times was dominated by fine clastics, with areally-limited, shallow marine and distal, debris-flow sandy systems.

Proto-Greenland and the Scandinavian mainland are considered unlikely to represent the source areas for potential Paleocene sands in the PL 425S acreage, because of the relative distance from provenance and the nature of the depositional sandy systems (i.e. areally-limited debris flows). Therefore, the East Shetland Platform is interpreted to provide the most likely source area for potential Paleocene sandy reservoirs in PL 425S.

These sands may have been derived from the southwest, representing the distal ends of gravity flow systems, most likely debris flows, deposited parallel to the underlying Mesozoic structural highs. Some of the Paleocene sands seen in the Statfjord area may be part of analogous depositional systems.

The distal nature of these flows, their unusual depositional mechanism, together with their modest thickness and limited distribution poses a serious uncertainty for them representing viable exploration targets.

Consequently, from a geological point of view, the presence of viable Paleocene sandy reservoir represents a high risk within PL 425S.

3.5 Source Rock Quality, Charge and Hydrocarbon Phase

The primary source rock in the Marulk Basin is the Upper Jurassic Draupne Formation, a marine unit with high Total Organic Content (TOC) and an oil-prone kerogen. The presence and maturity of the source rock in the Marulk Basin is proven by the occurrence of geochemically-similar black oils in the nearby fields of Snorre and Visund, as well as oil discoveries on the Manet Ridge (well 6201/11-1) and in wells 34/4-10R and 34/4-5.

The timing of hydrocarbon maturation and migration is uncertain, but published modelling results (Kubala et al. , 2003) date peak oil generation as Late Cretaceous, with increasing levels of maturity culminating in gas generation during the Paleocene.

Consequently, presence of source rock, quality and charge are not considered risk elements for the mapped prospects and leads within the evaluated acreage. However, timing for oil charge could be a potential risk with respect to the earliest trap formation for the Paleocene reservoirs.

3.6 Pressure Systems

High overpressures are proven in the Jurassic and Cretaceous sections of the Marulk Basin, thought to be due to disequilibrium compaction of shales. However, the Tertiary section has so far proven to be hydrostatically pressured.

Consequently, from the pressure point of view, top seal effectiveness is not considered to be a risk factor for the mapped Paleocene prospects in PL 425S.

4 Prospect Evalution

4.1 Seismic Interpretation and Depth Conversion

The seismic interpretation was based on all the available 2D and 3D seismic datasets listed in Chapter 2, Geological and Geophysical Database. Well tops from nearby wells were correlated to the seismic datasets to define the corresponding seismic horizons, Figure 4.1.

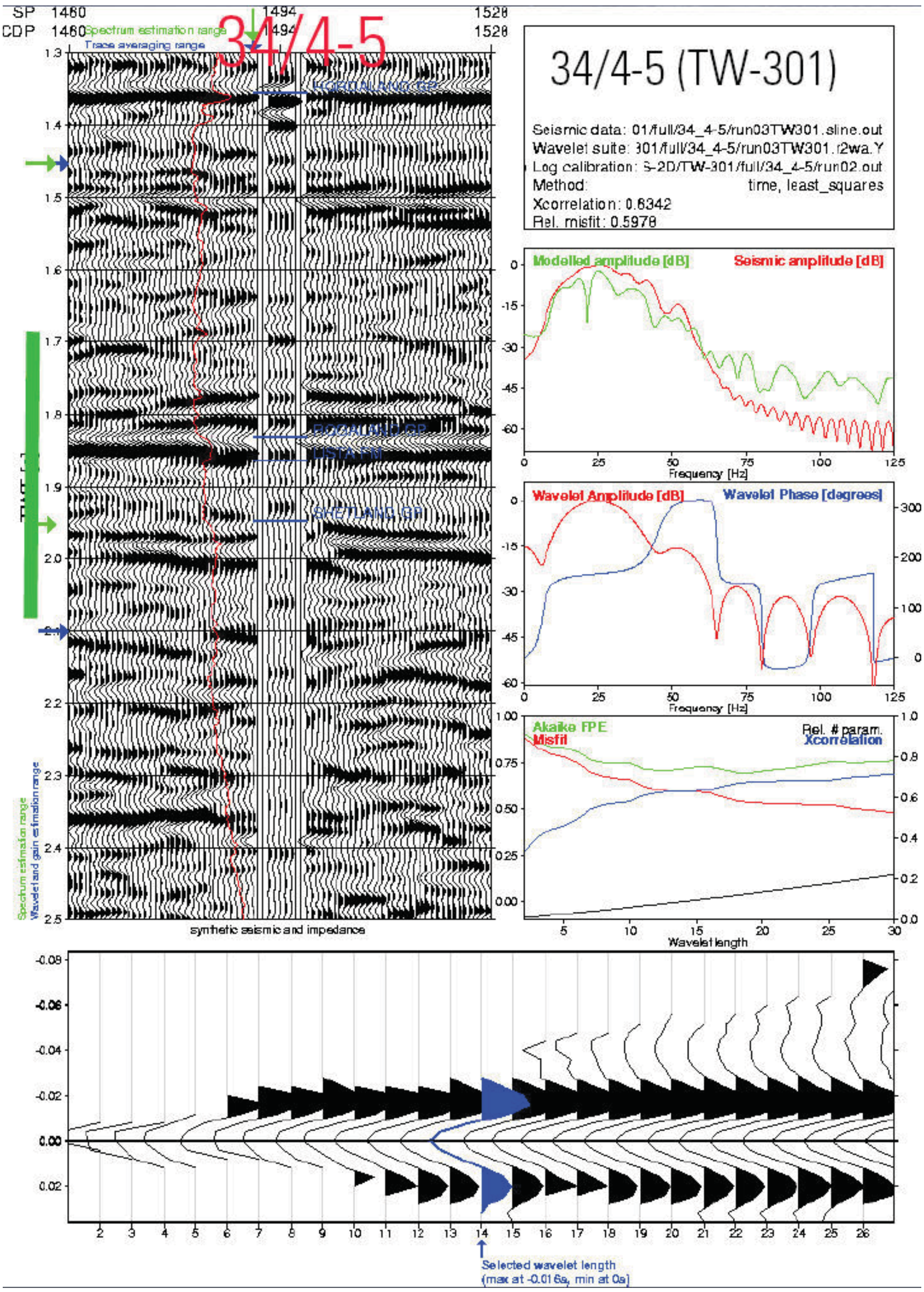


Figure 4.1 Well to Seismic Tie. From Schlumberger Inversion Study for PL 425S.

This prospectivity evaluation focused on the Paleocene play. No Ty/Våle/Egga Formations were found in the offset wells and no corresponding seismic units could be identified on seismic. Consequently, Top Paleocene, Top Lista and Top Cretaceous seismic markers were the only seismic horizons that could be confidently calibrated to seismic via nearby wells, and are the key interpreted seismic horizons that define the mapped prospect Lagen, Figure 4.2 and Figure 4.3. The definition of the "Top Sele" seismic horizon was based solely on its seismic character and its relative position with respect to Top Lista and Top Paleocene seismic markers, as the Sele Formation was not identified in the surrounding wells. This horizon represents the top of a seismic unit developed in the low between two structural highs at the north and south of the main mapped prospect, Lagen.

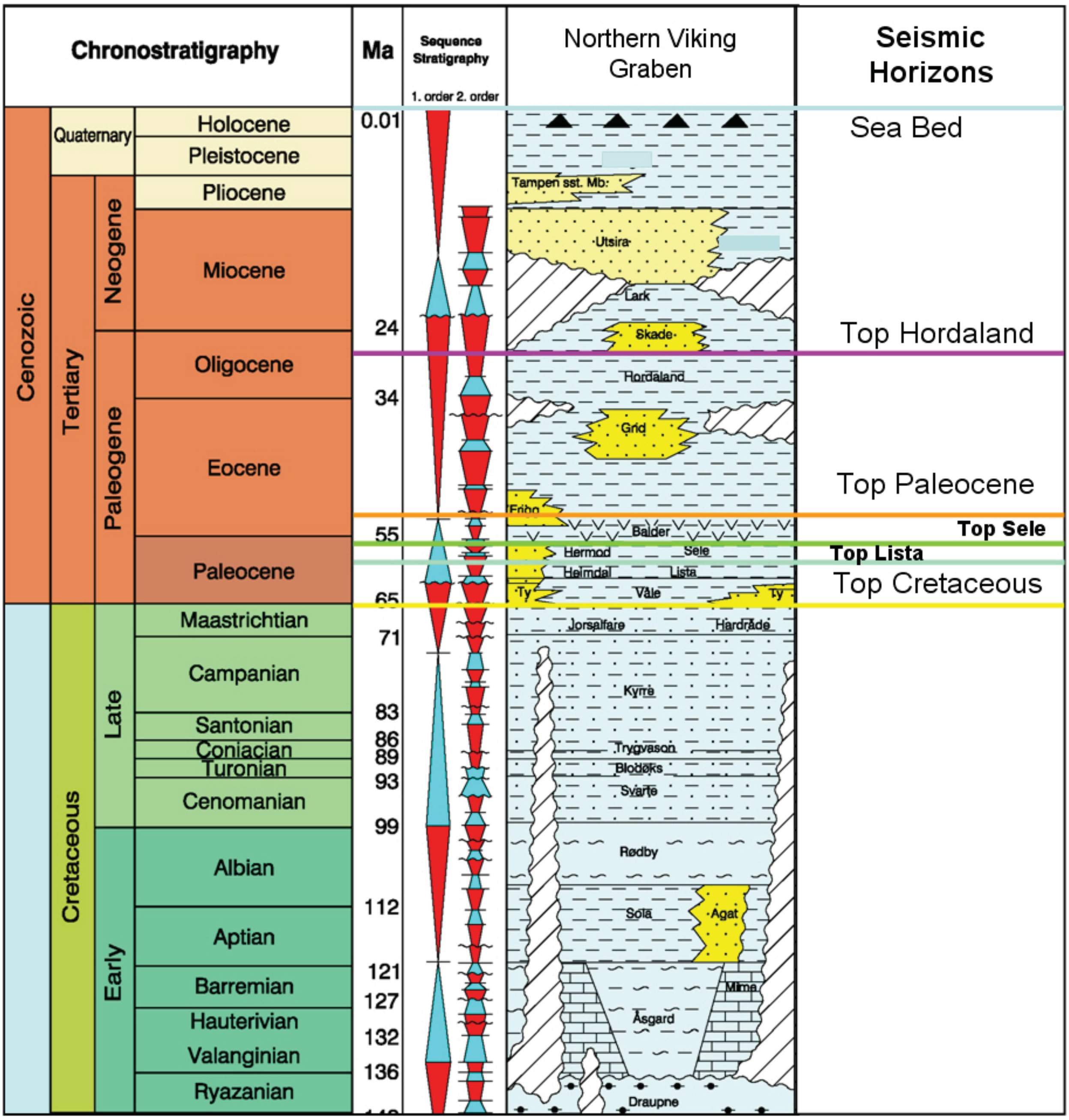


Figure 4.2 Interpreted Key Seismic Horizons.

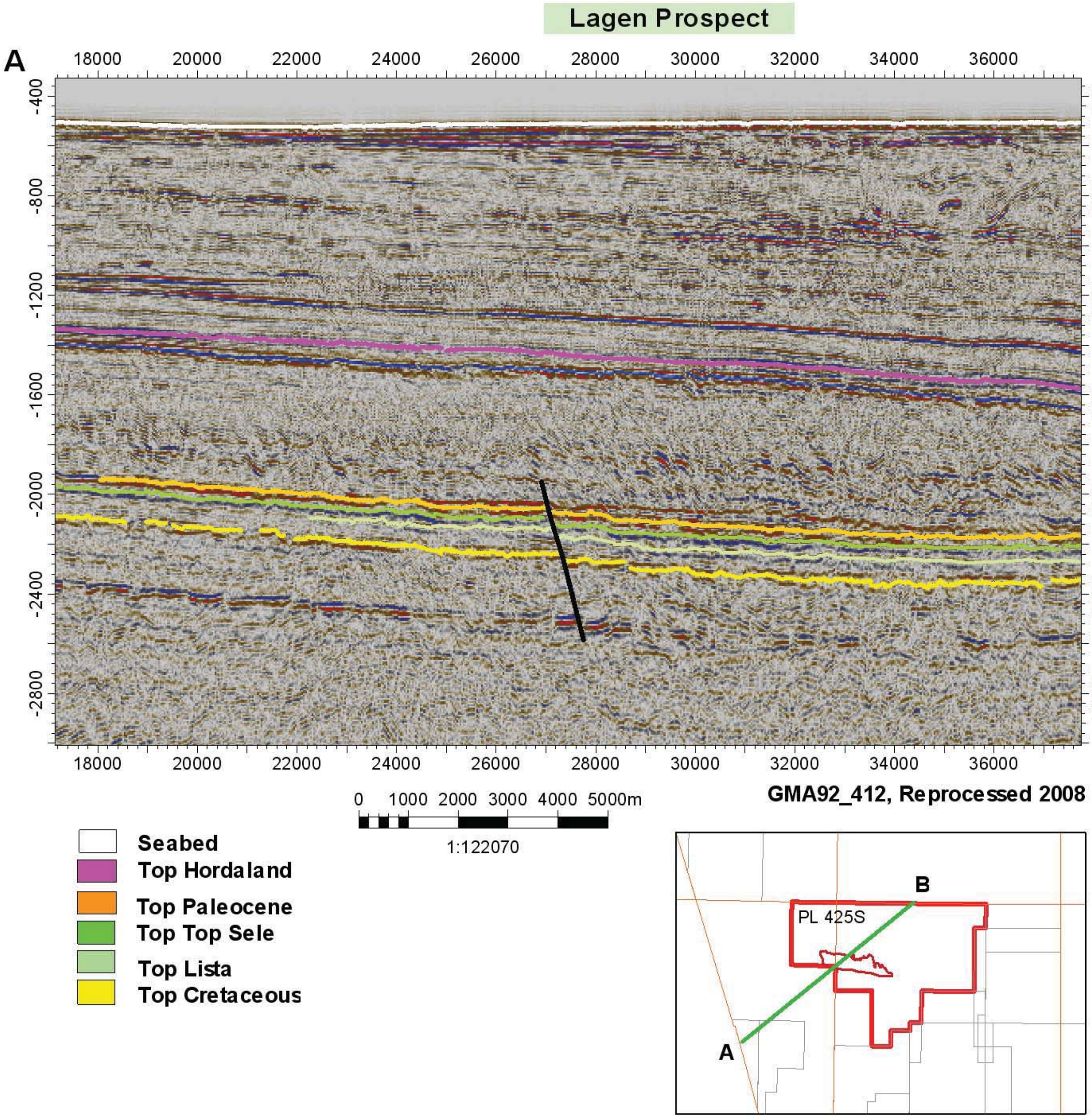


Figure 4.3 Interpreted Key Seismic Horizons.

The seismic horizons listed in Table 4.1 have been used for generating the velocity model for time to depth conversion.

Table 4.1 Well Calibrated Seismic Horizons Used for Time to Depth Conversion.

Well	Seabed		Top Hordaland		Top Paleocene		Top Cretaceous	
	TVDss	TWT	TVDss	TWT	TVDss	TWT	TVDss	TWT
34/2-3	388	509	1463.9	1489.4	1846	1864	1955.8	1959
34/2-2	386	509.6	1393.3	1452.4	1837.9	1843.8	1958.9	1957.1
34/2-4	391	514	1479	1479	1933	1934	2062	2045
33/5-2	310	410.1	1029	1131	1532.9	1649.4	1691.85	1805.7
33/5-1	340	450	1046.4	1157.8	1466.8	1594.2	1621.15	1736.2
6201/11-1	381	527	1237	1368	1752.9	1915.3	2007.8	2149.15
6201/11-2	373	507	1216.9	1341.7	1792	1953	2018.9	2150.5
34/4-5	379	482	1292	1346	1778.71	1819.58	1898.69	1934.42

Time to depth conversion has been carried out using the Velocity Manager software (Cambridge Petroleum Software), and a layer-based approach. The base of each layer was defined by the seismic horizons listed above. For each layer a velocity function was derived using the time and depth information at the well locations. The final function used was isochore (depth thickness) versus isochron (time thickness), which produced an average velocity field for each layer. The velocity model was then applied to the seismic two-way time horizons, resulting in initial depth maps. Residual depth errors at the well locations were calculated and subsequently gridded then this correction was applied to produce the final depth maps.

An important consequence of the depth-conversion was the change in geometry of the mapped Lagen prospect. On time-maps, Lagen is represented by a structural north - south trending structure defining a three way dip closure. After depth conversion, its orientation has changed to a west - east trending structure, and is smaller (Figure 4.4). This change in orientation and geometry is caused by lateral thickness- and velocity variations within the Hordaland Group, Figure 4.5 and Figure 4.6.

The apparent change in the structure following the depth conversion was subsequently verified by generating a second velocity model using only the migration velocities from the seismic and applying this to the time horizons. The results of this showed that the structure at the Lagen prospect was similar to that observed from the layer-based depth conversion, Figure 4.7.

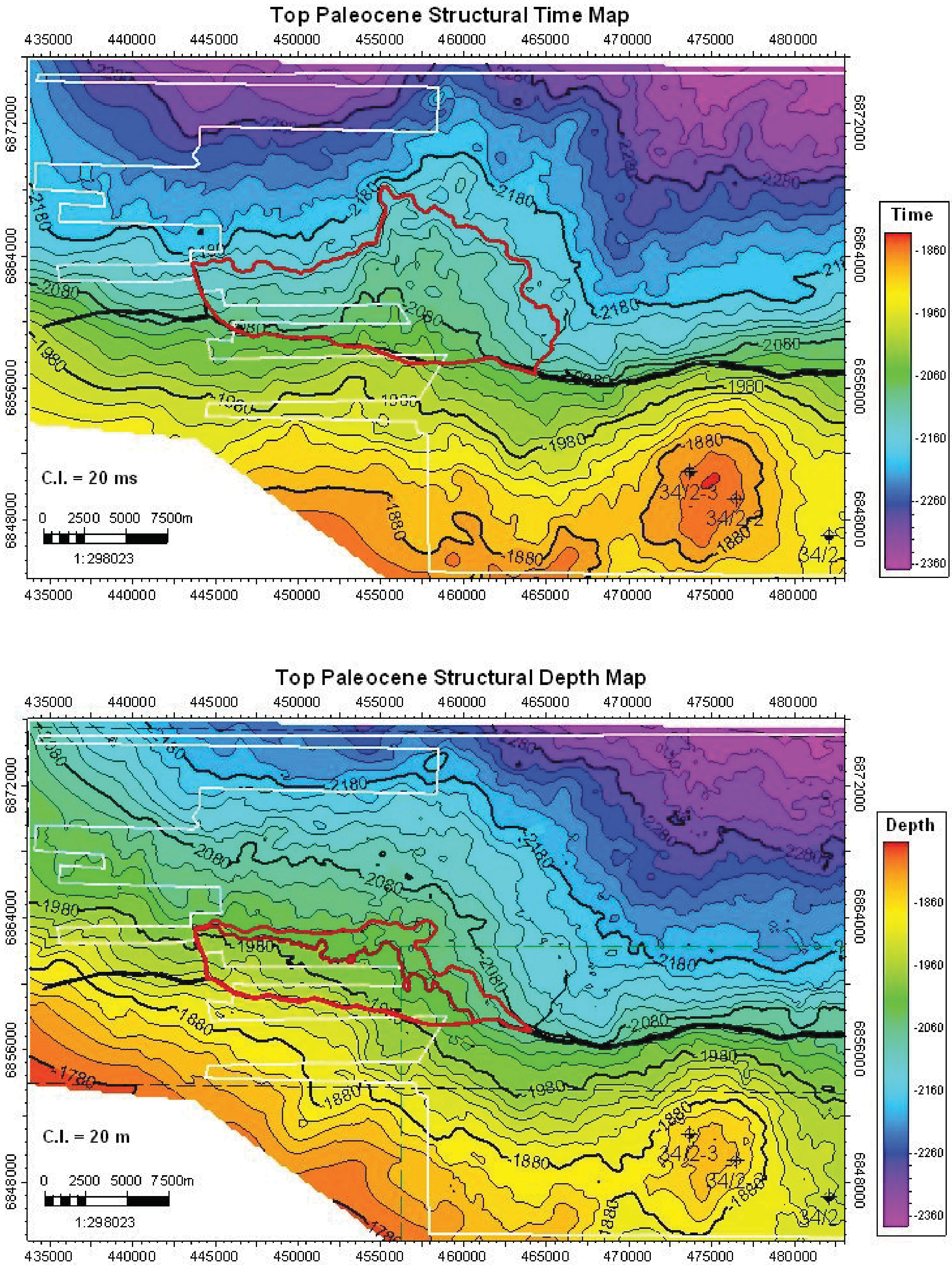


Figure 4.4 Top Paleocene Time and Depth Maps. Note the reduced area of the Lagen Prospect (red outline, see Chapter 4.2 for detailed prospect description) structure after depth conversion. This is caused by lateral and vertical thickness variations within the overlying Hordaland Group succession (see also Figure 4.5).

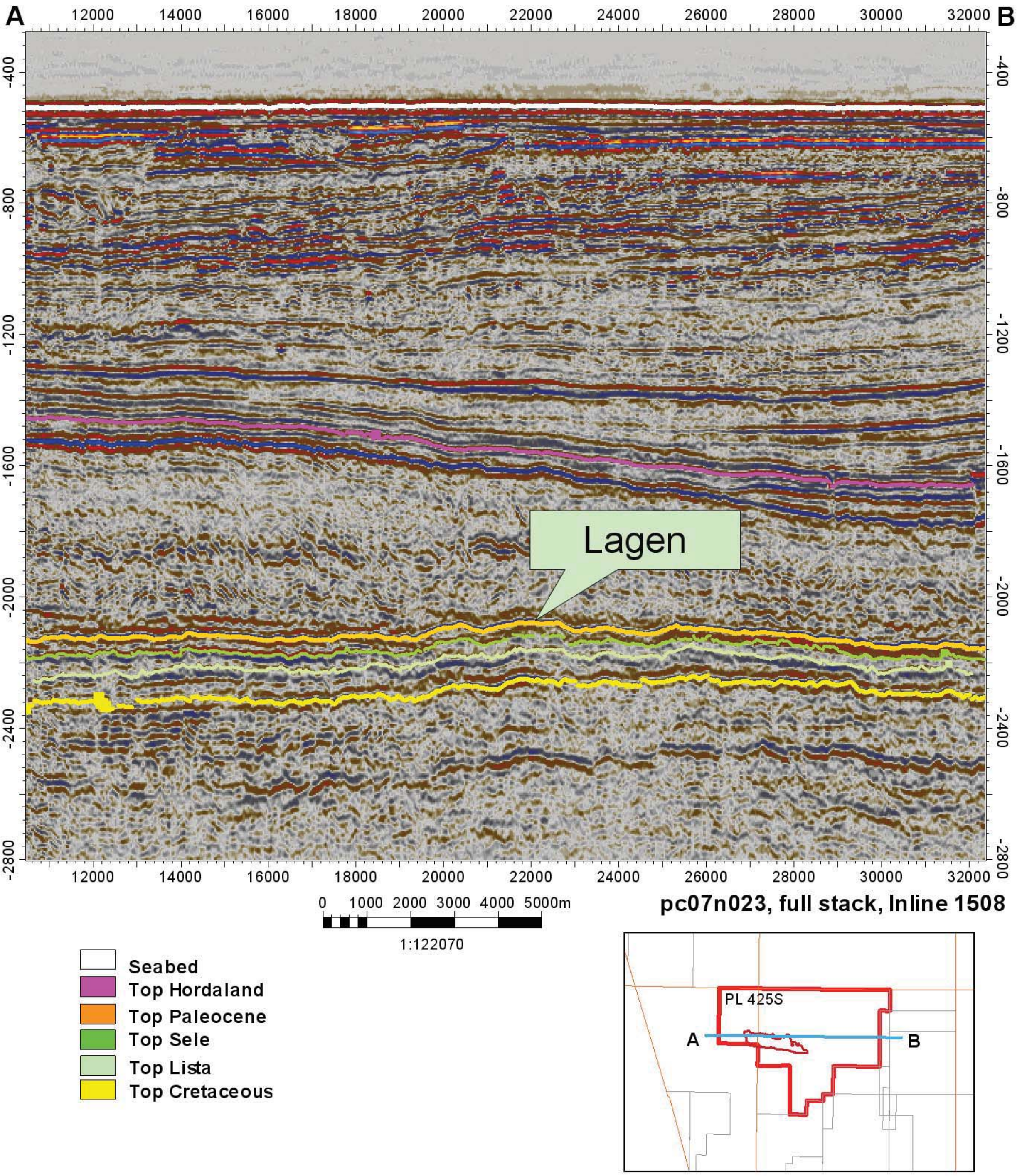


Figure 4.5 Strike Seismic Line Over the Lagen Prospect. Vertical and lateral thickness changes (as well as reduced Vp values) within the Hordaland Group succession impact orientation and geometry (in depth) of the Lagen prospect structure (see also next figure).

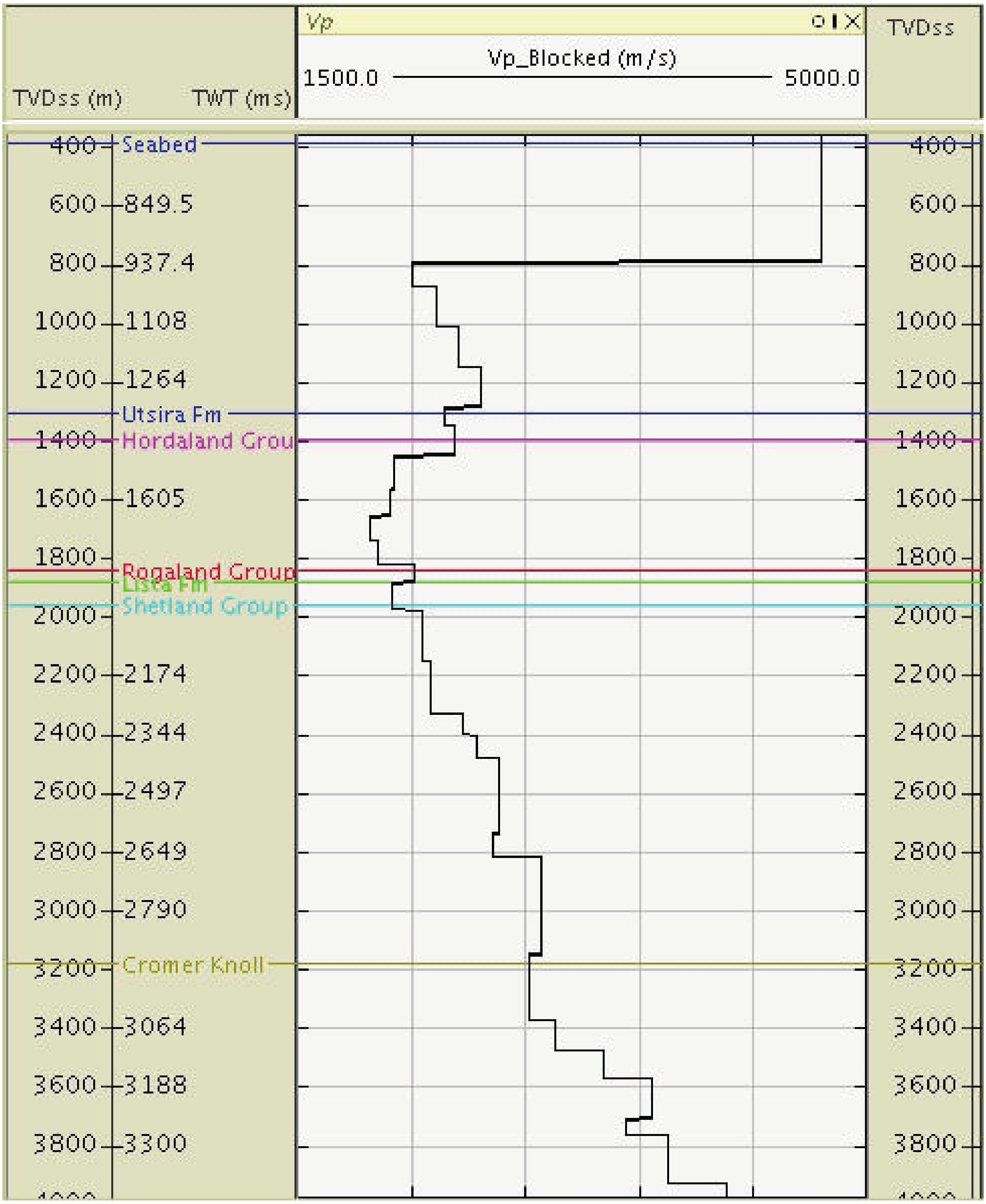
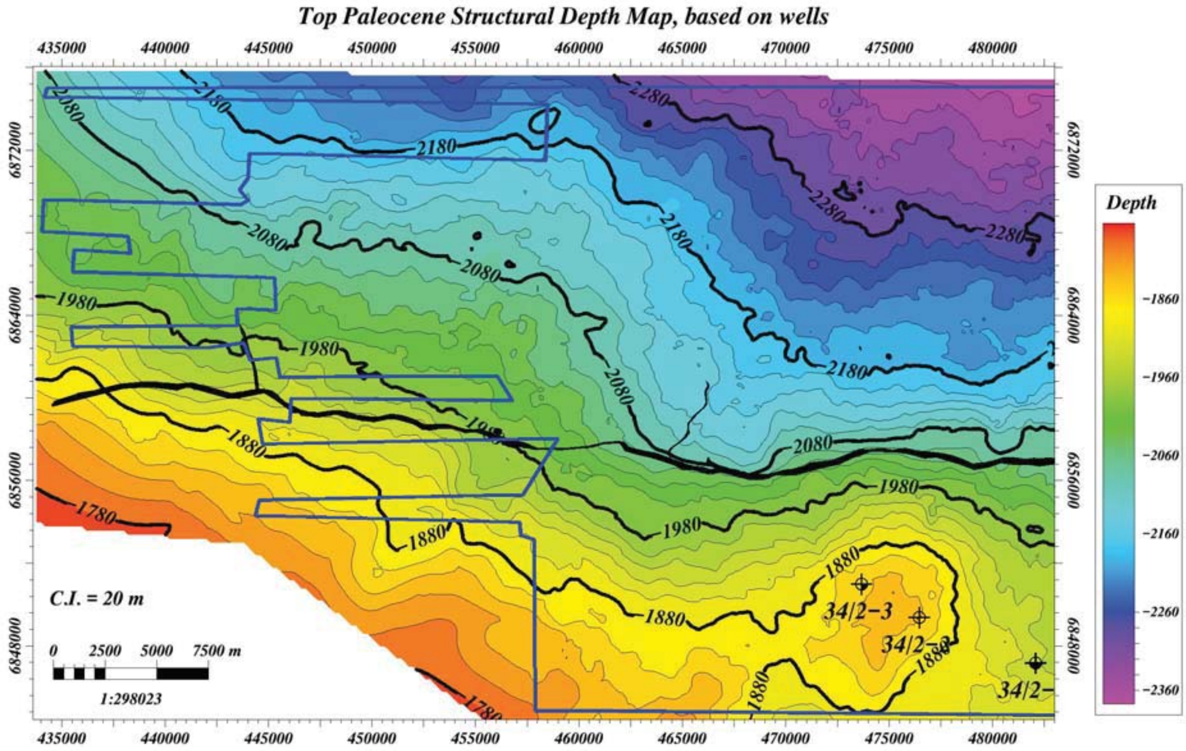


Figure 4.6 Blocked Vp Log, Well 34/2-2, showing reduced values within the Hordaland Group Section.



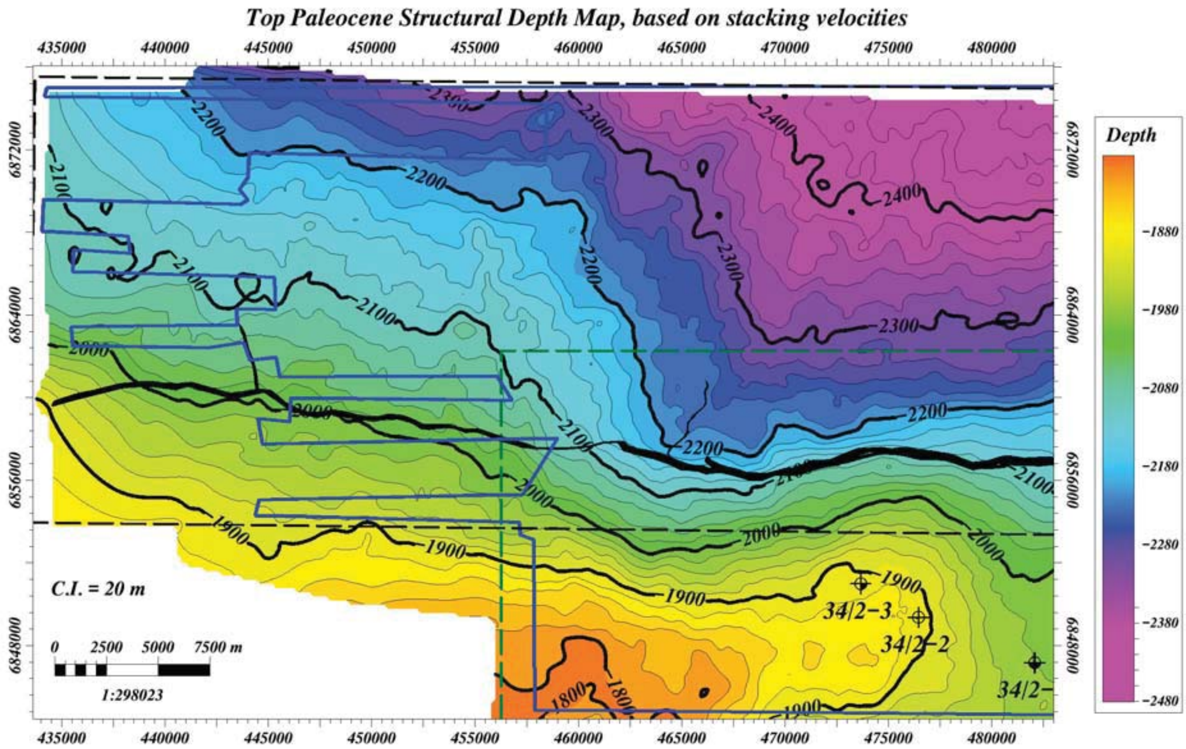


Figure 4.7 Comparison Between Depth Conversion Models.

4.2 Lagen Prospect

The Lagen prospect, the main prospect in the acreage, consists of a hanging wall fault block which forms a three-way dip closure at Paleocene levels. It covers an area of approximately 50 km^2 straddling Blocks 33/3 and 34/1. Its crest lies at 1935 m MSL (Top Sele), and the spill point at 2040 m MSL. This defines a potential (maximum) hydrocarbon column height of 105 m.

Lagen was classified as a lead in the APA 2006 evaluation. It was defined on two-way-time (TWT) maps and interpreted as a combined structural/stratigraphic trap, comprising a Paleocene reservoir analogous to the Ty/Egga Formation. Presence of reservoir and trap were then recognized as the critical risks for prospectivity.

To address these critical risks, Petro-Canada has, in addition to the acquisition and purchase of 3D seismic data, carried out the following technical activities:

- Seismic mapping (Chapter 4.1)
- Special seismic studies (Chapter 4.3)
- Petrophysical analyses (Chapter 4.2)

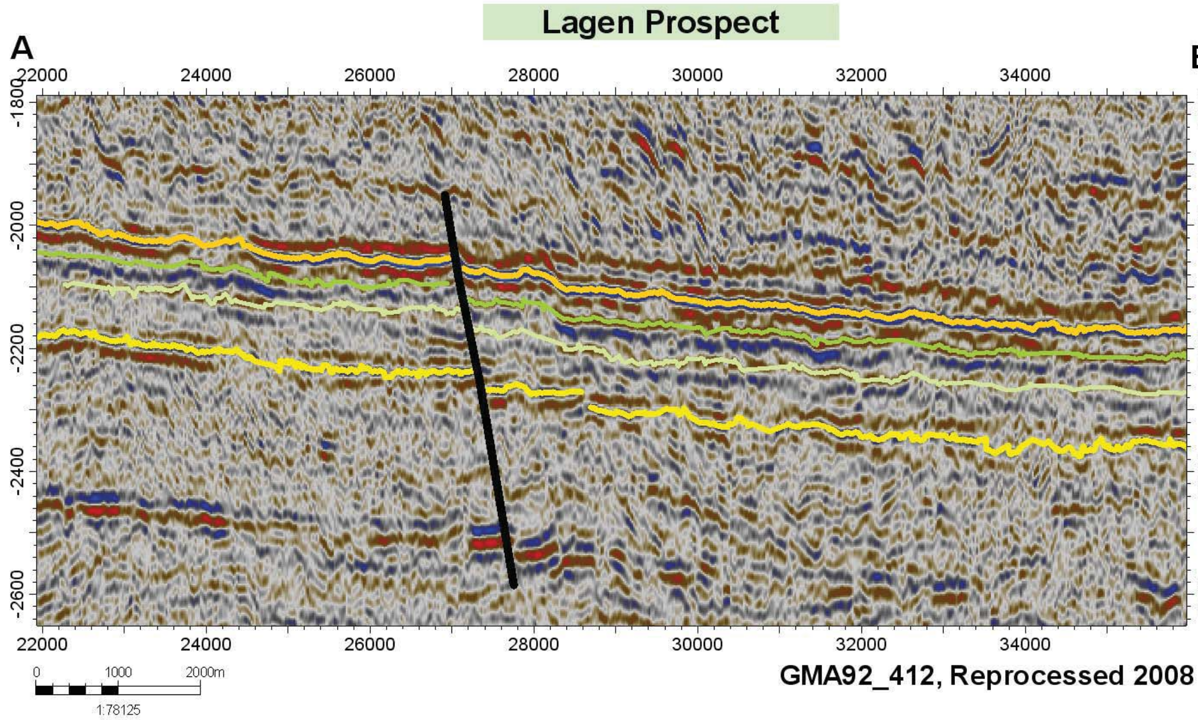
Trap and Seal definition

The trap consists of a hanging wall fault block which forms a three-way dip closure both at Top Lista and Top Sele levels. This trap is bounded by west to east and north to south trending faults, Figure 4.8 and Figure 4.9.

Within the wells in the area, Paleocene sandstones were encountered mostly within the lower part of the Paleocene section. However, the Top Lista seismic marker is the stratigraphically lower marker in the Paleocene section that could be confidently interpreted in the study area. Consequently, the Lagen prospect was defined at this seismo-stratigraphic level. Seismic mapping also indicated that, within the Lagen closure area, an additional seismic unit was present within the upper part of the Paleocene section, Chapter 4.1, Seismic Interpretation and Depth Conversion. This unit has been generally correlated to the Sele Formation and interpreted to represent an additional (but risky) potential exploration target. Both seismic horizons which define these seismic stratigraphic units (Top Lista and Top Sele) were clearly defined on seismic and easily mappable.

A significant issue related to seal effectiveness is possible sand to sand juxtaposition across the prospect bounding faults. Across these faults, potential sands are likely to be in contact, because the assumed thickness (50 m) is greater than the throw of the faults (15-25 m). Another consideration with regards to fault seal efficiency is that these potential reservoirs have a present-day depth of burial of ca. 2000 m. This depth is not considered optimal to develop mylonitization and/or fault seal diagenesis, which would have improved fault seal effectiveness.

Consequently, fault seal effectiveness is now regarded as another key risk for the Lagen prospect.



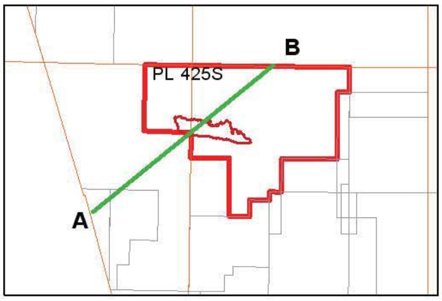
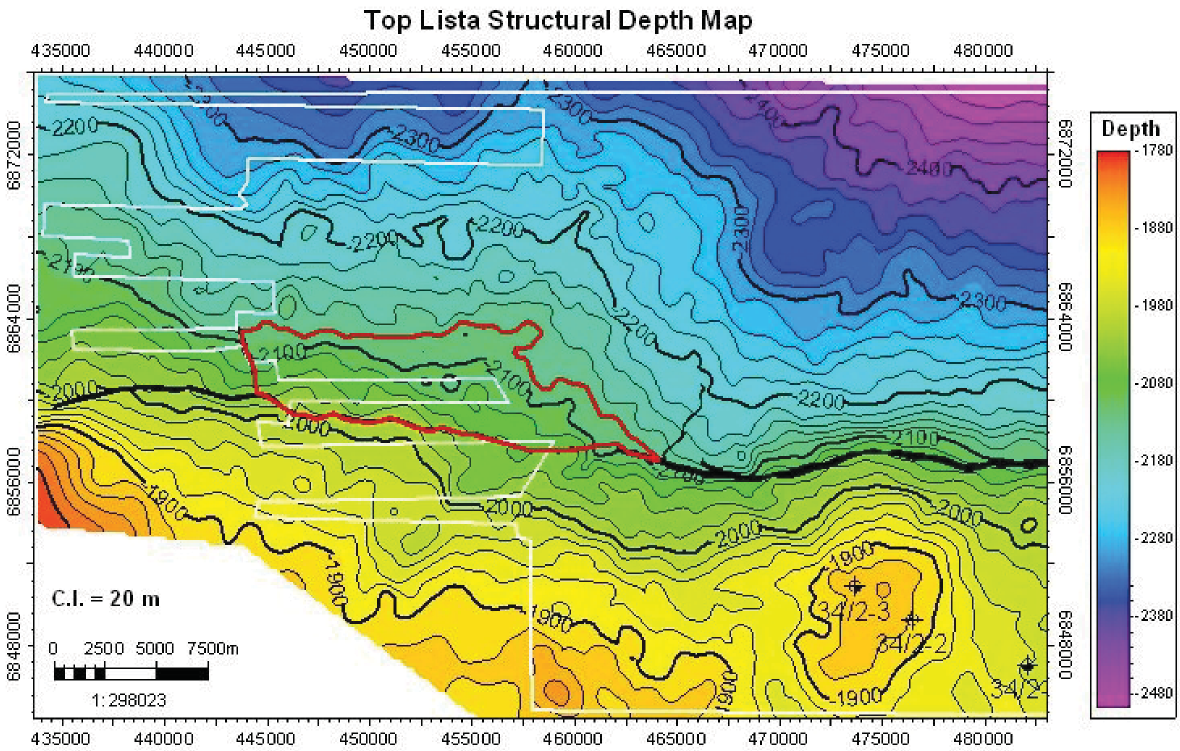


Figure 4.8 Lagen Prospect, Seismic Dip Line. The Lagen Prospect is a hangingwall structure bounded by faults to the south and west. Within this structure, exploration targets are interpreted within the Lista and Sele Formations (Top Sele and Top Lista seismic markers). Note the possible sand-to-sand juxtaposition across fault, which negatively impacts the risk related to lateral seal effectiveness.



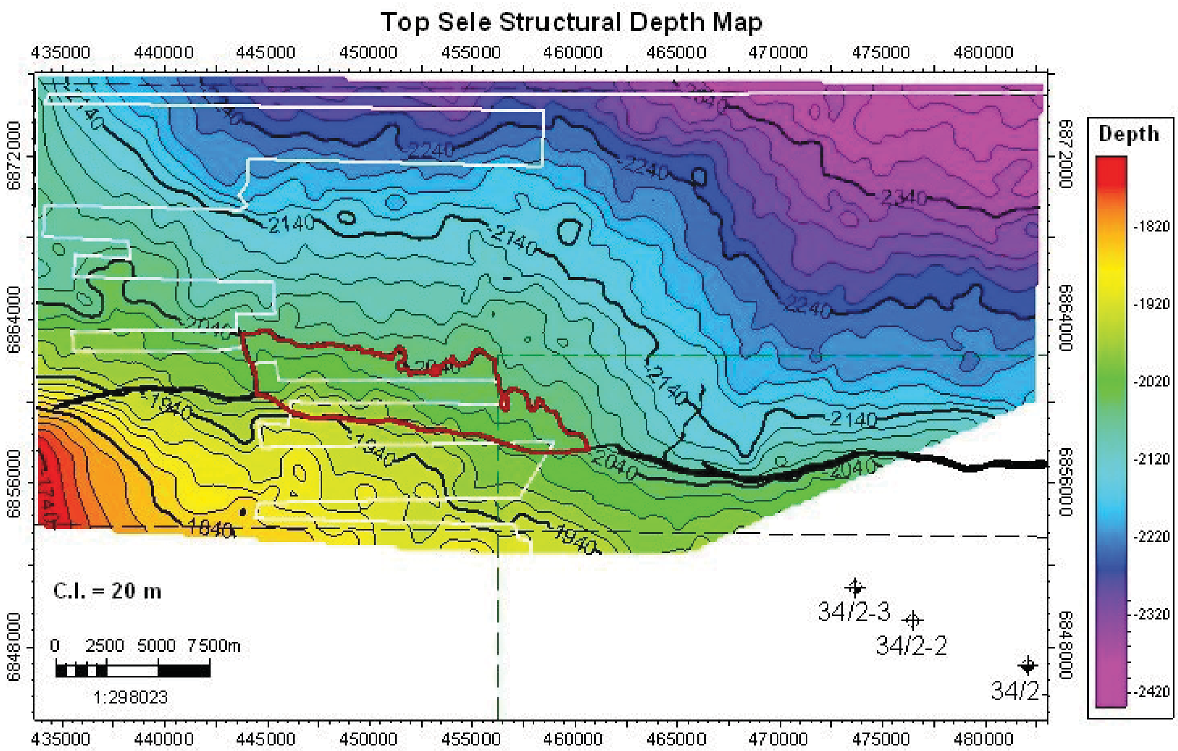


Figure 4.9 Lagen Prospect (red outline), Top Sele and Top Lista Depth Maps.

Presence of Reservoir

In Chapter 3.4 we described the occurrence and the depositional context of Paleocene sandy reservoirs in the study area. We also saw that no such reservoirs were found in the offset wells of PL 425S. In this chapter we review the occurrence of these reservoirs in the North Sea and Norwegian Sea, and the consequent impact on reservoir presence in the PL 425S acreage.

In the Central North Sea, sand occurrence within the Paleocene section appears to correlate to an increased thickness of the whole Paleocene stratigraphic interval, Figure 4.10. The relative thickenings of these units may be indicative of basin depocenters and preferred loci for sand accumulations. Isopach maps are therefore commonly used as a tool to help identify potential sand fairways.

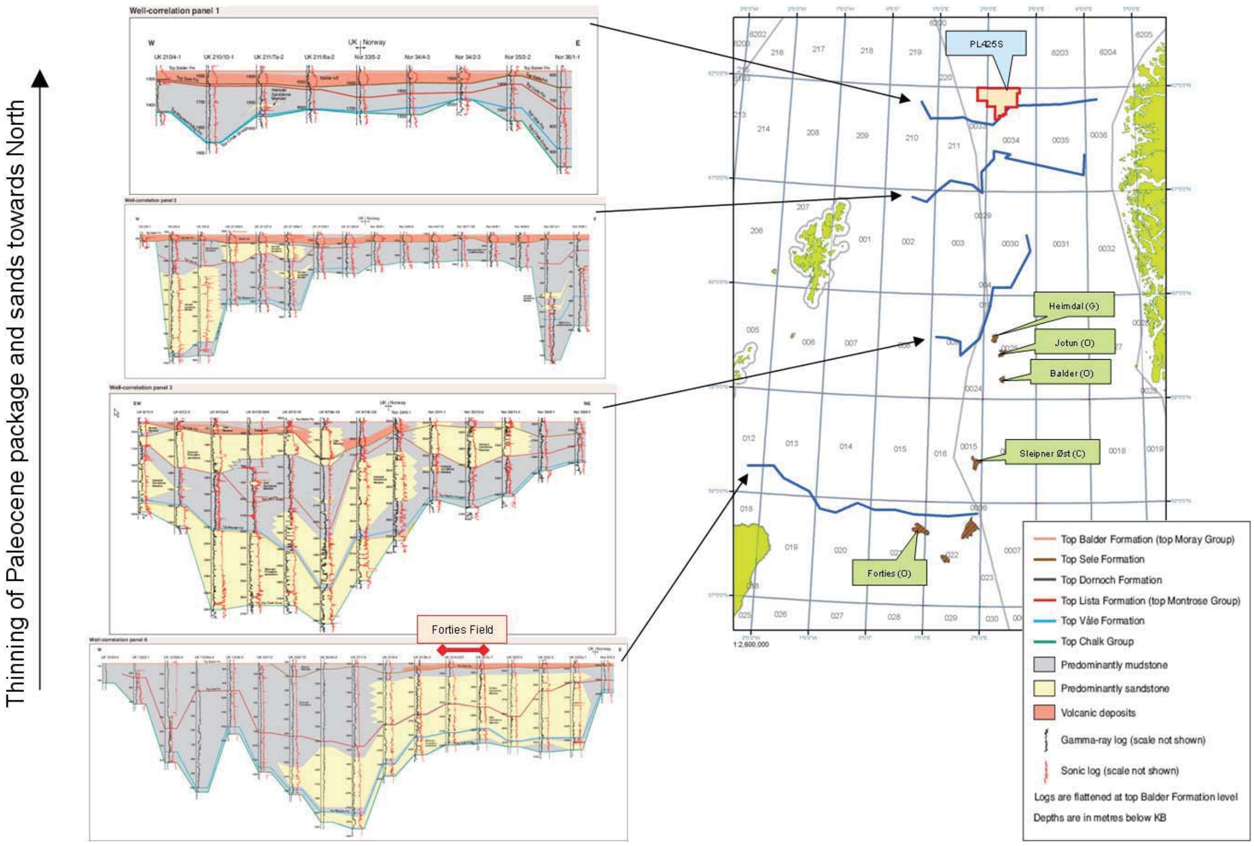


Figure 4.10 Occurrence of Paleocene sandstones in the North Sea. Paleocene sandstones of the North Sea deposited in areas characterised by greater accomodation. This resulted in a reative thickness increase of the whole Paleocene section. The presence of a large sediment source area, i.e. the East Shetland Platform, was also crucial to the development and occurrence of these sandstones.The corresponding depositional systems were dominated by turbidite deposition, where sediments were transported over long distances. These factors seem not to be present in PL 425S acreage and surrounding areas. Also, note the overall thinning of the Paleocene succession towards the north in the PL 425S area and the increase in shaliness of the Paleocene section from south to north. From Ziad, A et al., 2003, the Millennium Atlas.

Consequently, to identify possible Paleocene sand fairways in the study area, a regional isopach map of the Paleocene succession, covering the Northern North Sea and the Norwegian Sea areas, was prepared, Figure 4.11. This map indicates a correspondence between overall Palaeocene thickness with presence of sands, as observed at the Ormen Lange Field and the 6302/6-Tulipan discovery. This observation concurs with data from the North Sea.

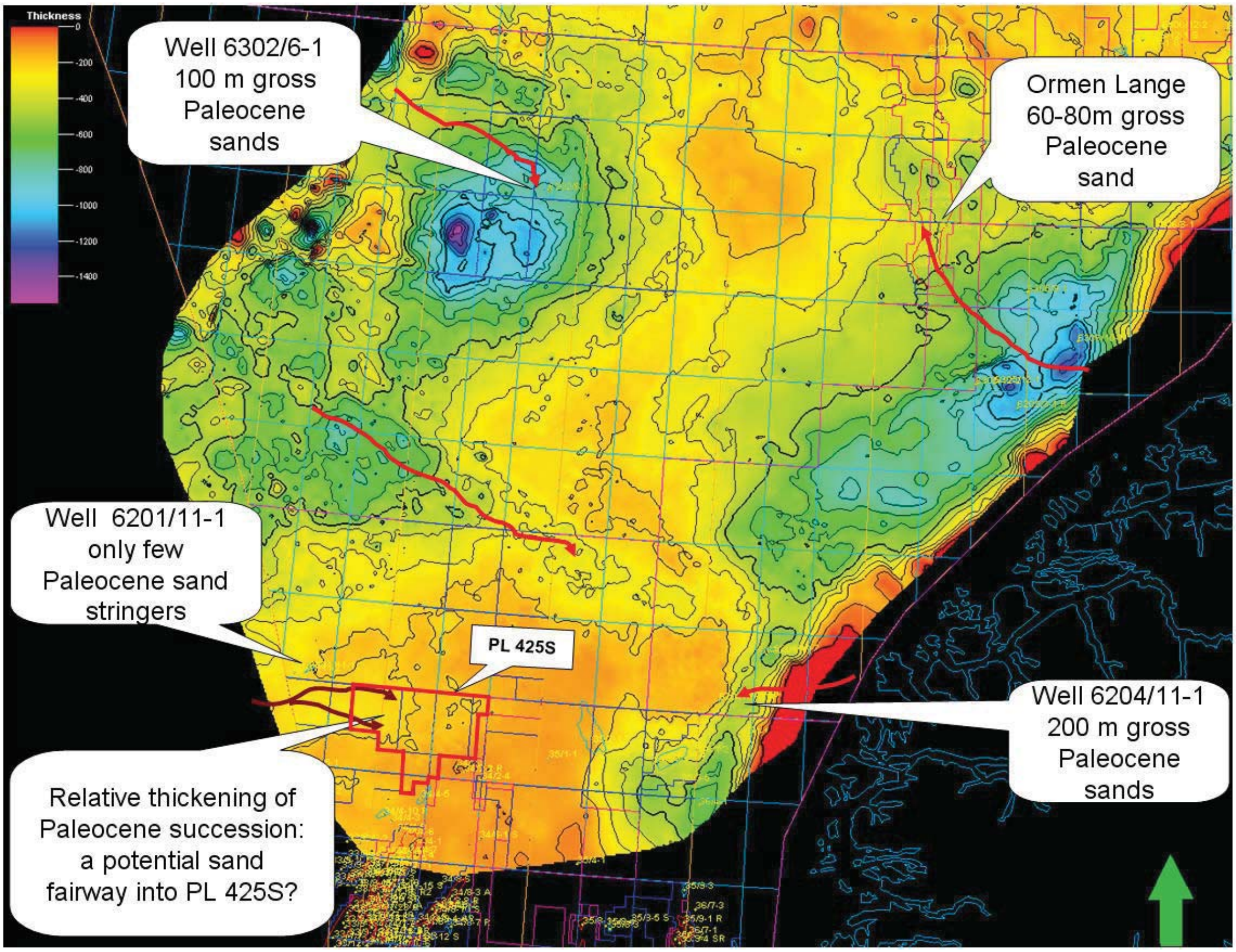


Figure 4.11 Regional Isopach Map of the Paleocene Succession. There seems to be a general correspondance between occurrence of Paleocene sandstones and relative thickness increase of the whole Paleocene succession in the Norwegian Sea, as proved by wells at the Ormen Lange Field, Tulipan Discovery and in the Sløreboth Basin. This is in line to what observed in the North Sea. Red arrow are interpreted sediment supply directions. Only a relative thickening of the Paleocene succession is observed within the PL 425S area, but not of the same magnitude observed in the other areas where sandstone reservoirs have been proved.

Across the PL 425S study area however, the Paleocene section is thinner with respect to the areas to the north where sands are proven. A narrow "nose" of relative thickness increase is observed in the western part of the acreage.

This observation alone does not, however, help de-risking presence of sands within the study area and in particular at the Lagen prospect location.

Petrophysical Analysis

Another way of addressing the uncertainty related to the presence of Paleocene sandstone reservoirs in the study area was to undertake petrophysical analyses of wire line logs to define stratigraphic stacking patterns. Petro-Canada carried out a detailed petrophysical analyses on the Paleocene sections of seven nearby wells in the area, namely:

211/7-2re (UK)
33/5-1
33/9-5
34/2-2
34/4-3
6201/11-2
6204/11-1

Of these, only well 6204/11-1 in the Slørebotn Sub Basin to the east proved a significant thickness (up to 200 m gross) of Paleocene sands, mostly represented by shallow marine or deltaic deposits. Only sand stringers or 1 m-thick sandy intervals were proven in the other wells, with the only exception being well UK211/7-2re, which proved a hydrocarbon-bearing, 10 m-thick (gross) Paleocene sand interval, Figure 4.12, Figure 4.13 and Figure 4.14. Log stacking patterns proved negative with regards to the development of significant sandy intervals in all the investigated wells.

Petrophysical analysis therefore indicates that presence of sand represents a very high risk for the Lagen Prospect.

Quality of Reservoir

Results from the CPI analyses carried out by Petro-Canada in the present study, as well as published average porosities from UK and Norwegian Paleocene fields were used to derive porosity-depth trends, Figure 4.15. These trends indicate that any Paleocene sand at Lagen's present-day depth could yield excellent reservoir properties. Thus, reservoir quality is not considered to be a substantial risk at Lagen.

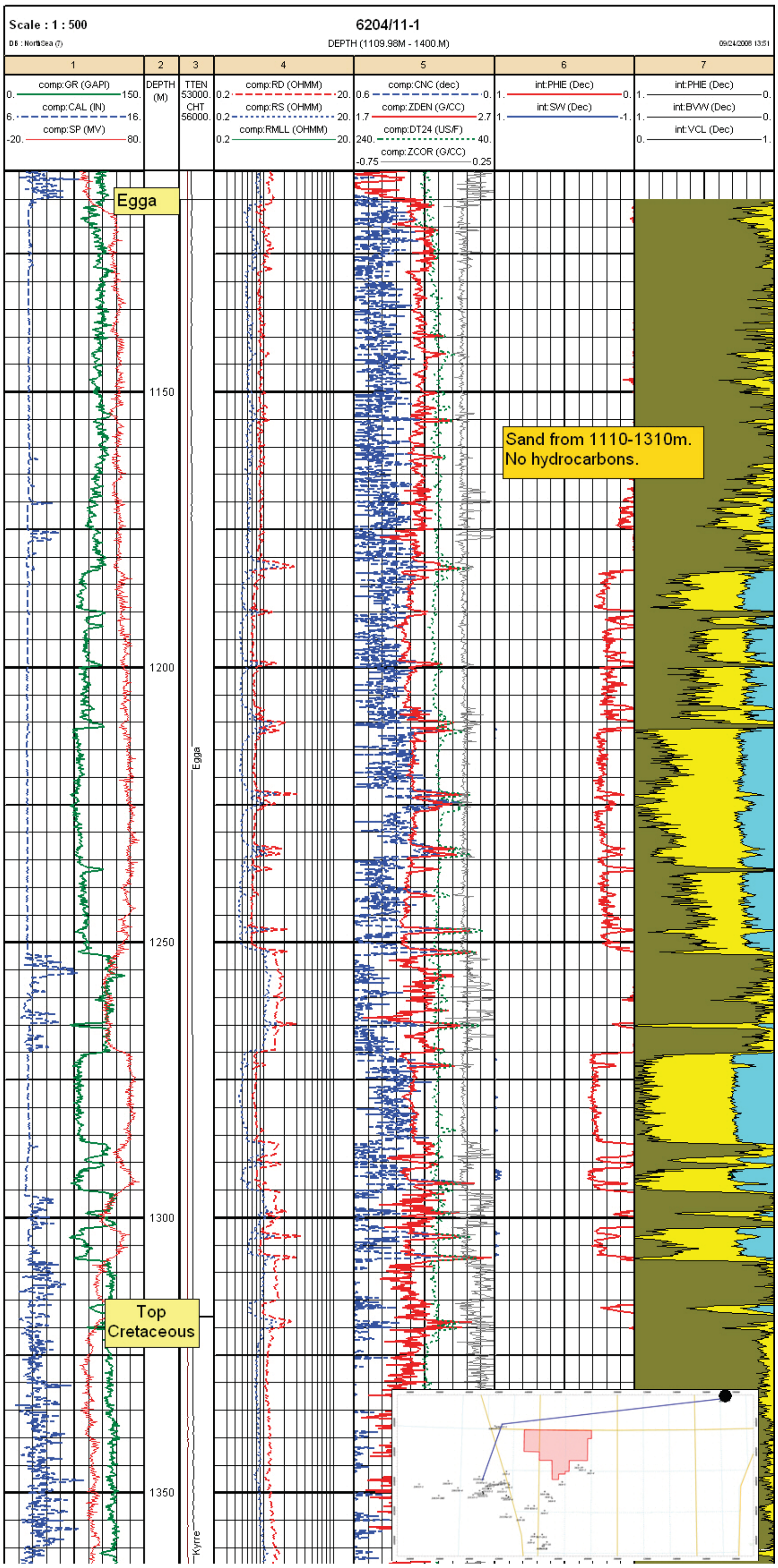


Figure 4.12 CPI Analysis for selected wells. The most important occurrence of Paleocene sandstones is in well 6204/11-1, about 60 Km away from the PL 425S acreage. Nearby wells only display thin stringers or a maximum of 10m sandy interval within the Paleocene section, see Figures 4.13 and 4.14.

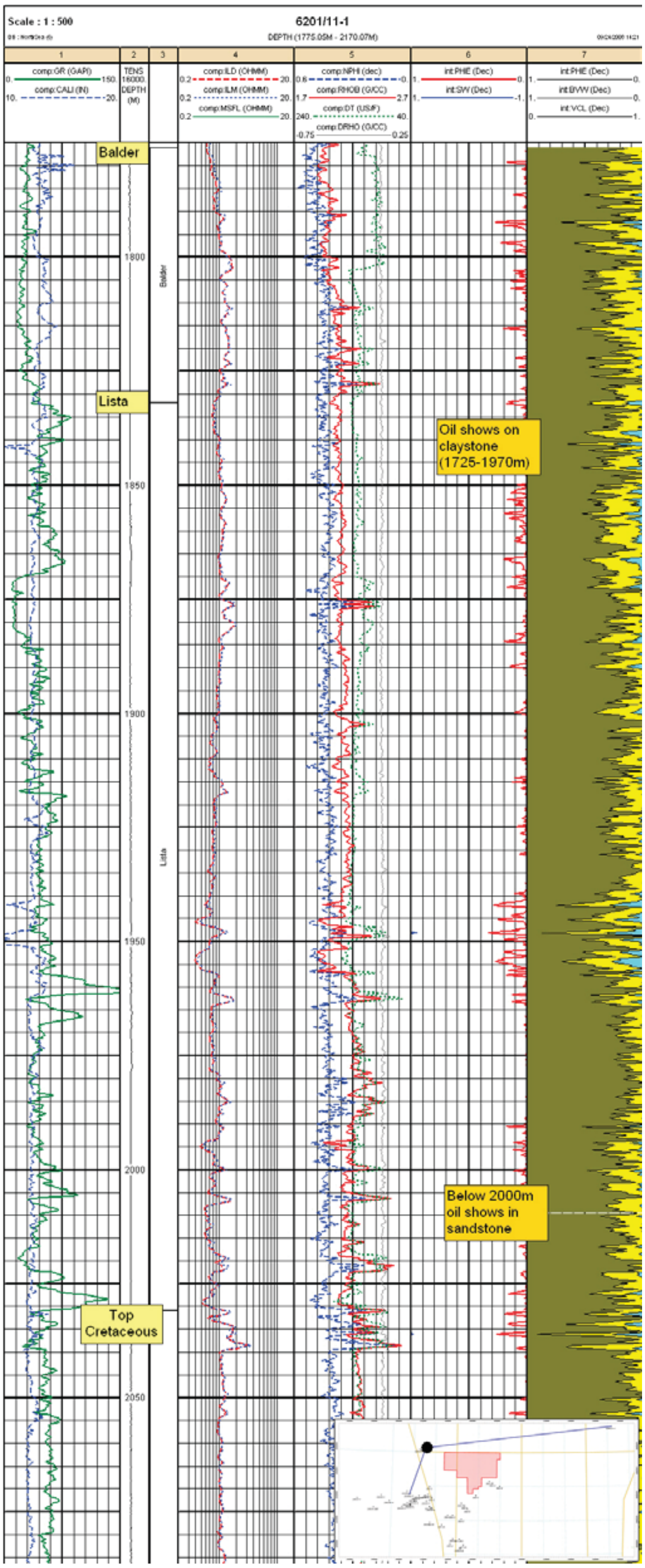


Figure 4.13 CPI Analysis for Well NO6201/11-1.

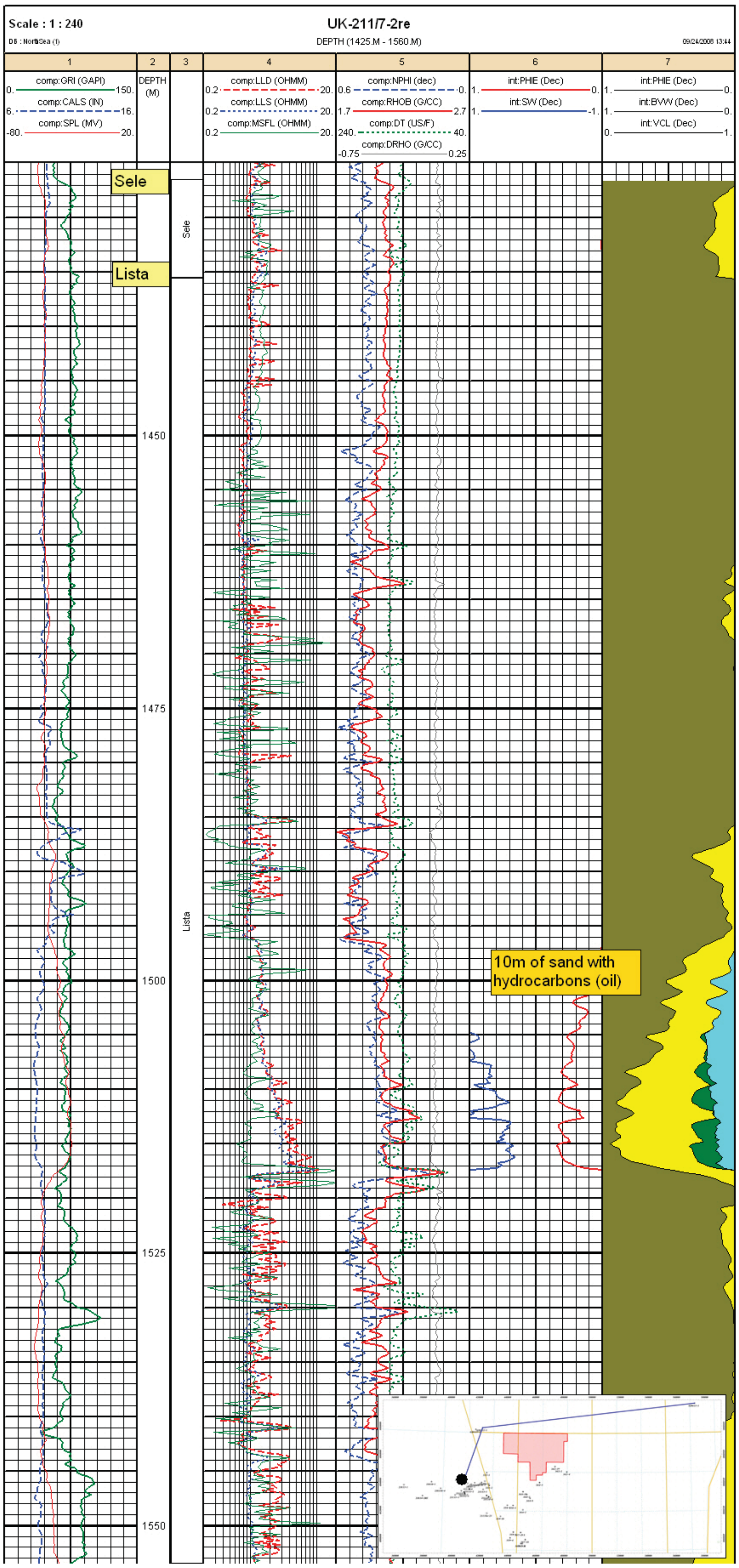


Figure 4.14 CPI Analysis for Well UK211/7-2re.

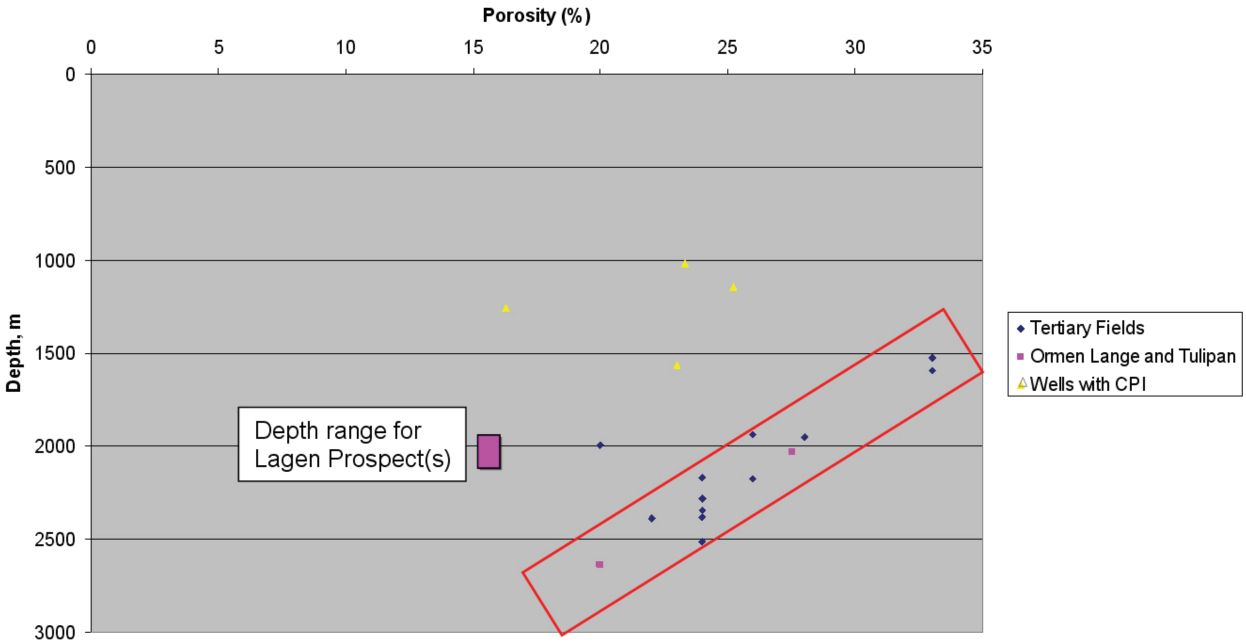


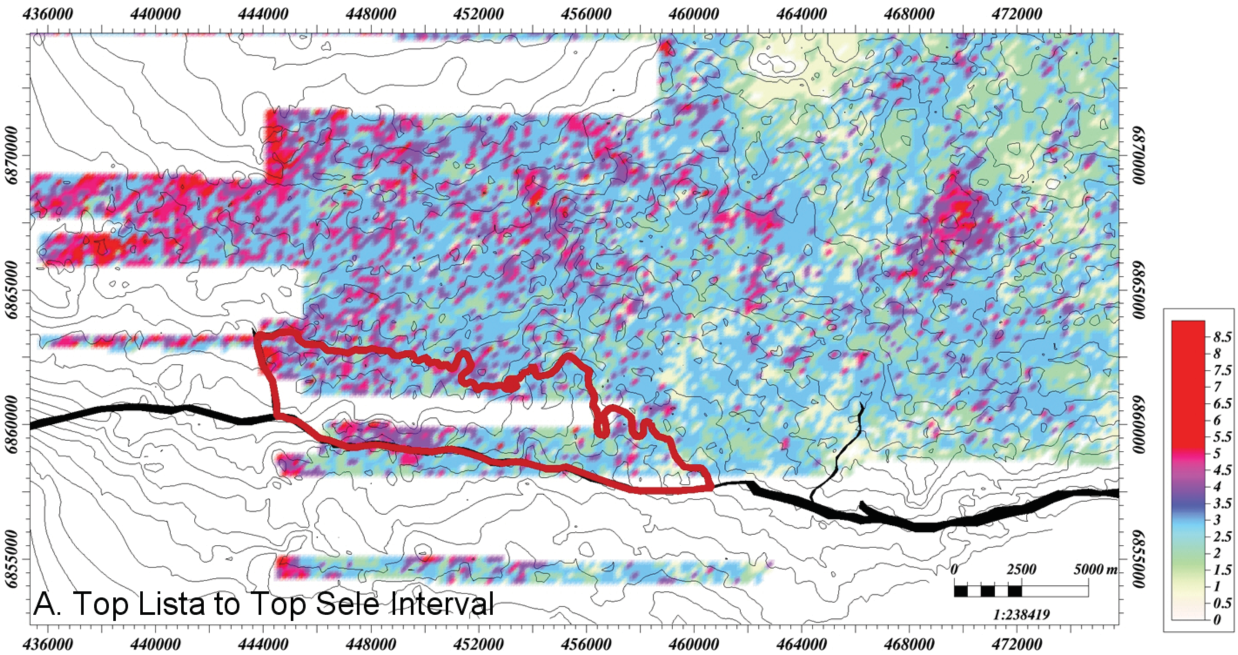
Figure 4.15 Average Porosity of North Sea Paleocene Reservoirs (Corrected for Water Depth).

4.3 Geophysical Special Studies

Presence of viable Paleocene reservoir is one of the main geological risks related to the Lagen prospect. Consequently, in order to identify sand reservoirs and possible associated hydrocarbons, the following geophysical special studies have been carried out:

Seismic attributes: Number of Zero Crossings and RMS Amplitude.

With the objective of identifying sedimentary structures within the Paleocene seismic units, the number of zero crossings- and RMS amplitude attributes were generated and combined with the respective isochore maps (i.e., Top Cretaceous to Top Lista. Top Lista to Top Sele. Top Sele to Top Balder). Neither the number of zero crossings attribute, Figure 4.16, nor the RMS amplitude extraction at Top Sele or Top Lista (calculated at different seismic offsets), Figure 4.17, support the presence of sands (or hydrocarbons) within the investigated units.



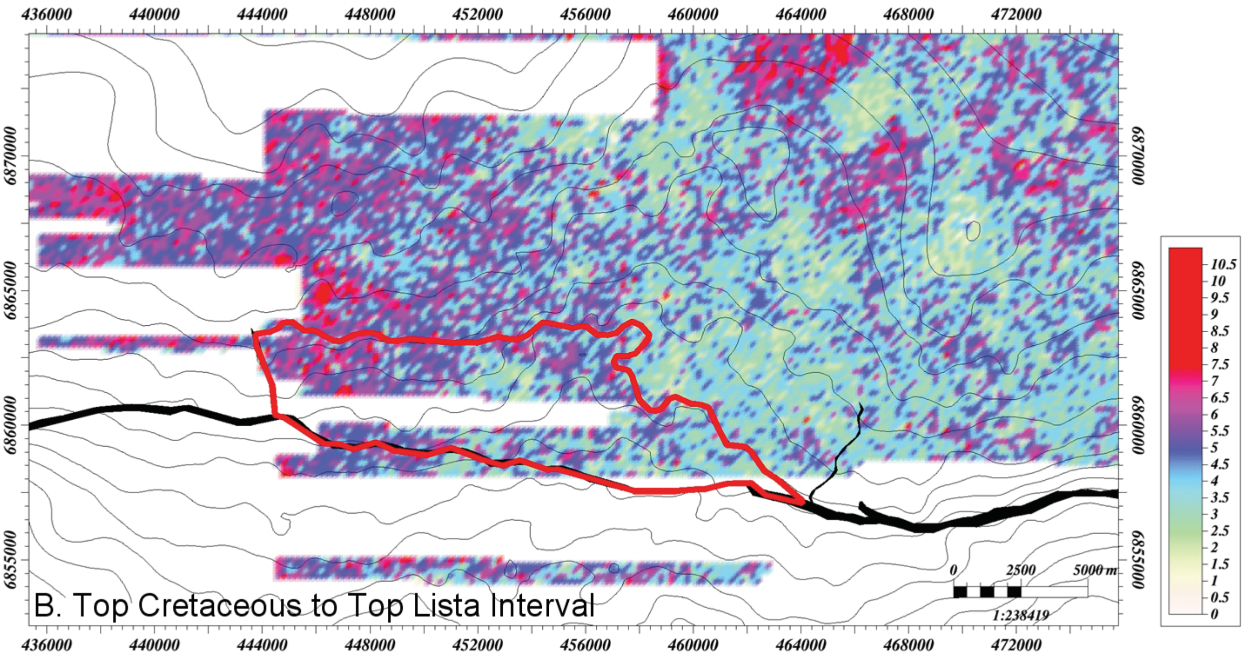


Figure 4.16 Zero Crossing Attribute for the Sele (A) and Lista (B) Seismic Intervals. Red outline in A. and B. is Lagen Prospect, at Top Sele and Top Lista, respectively.

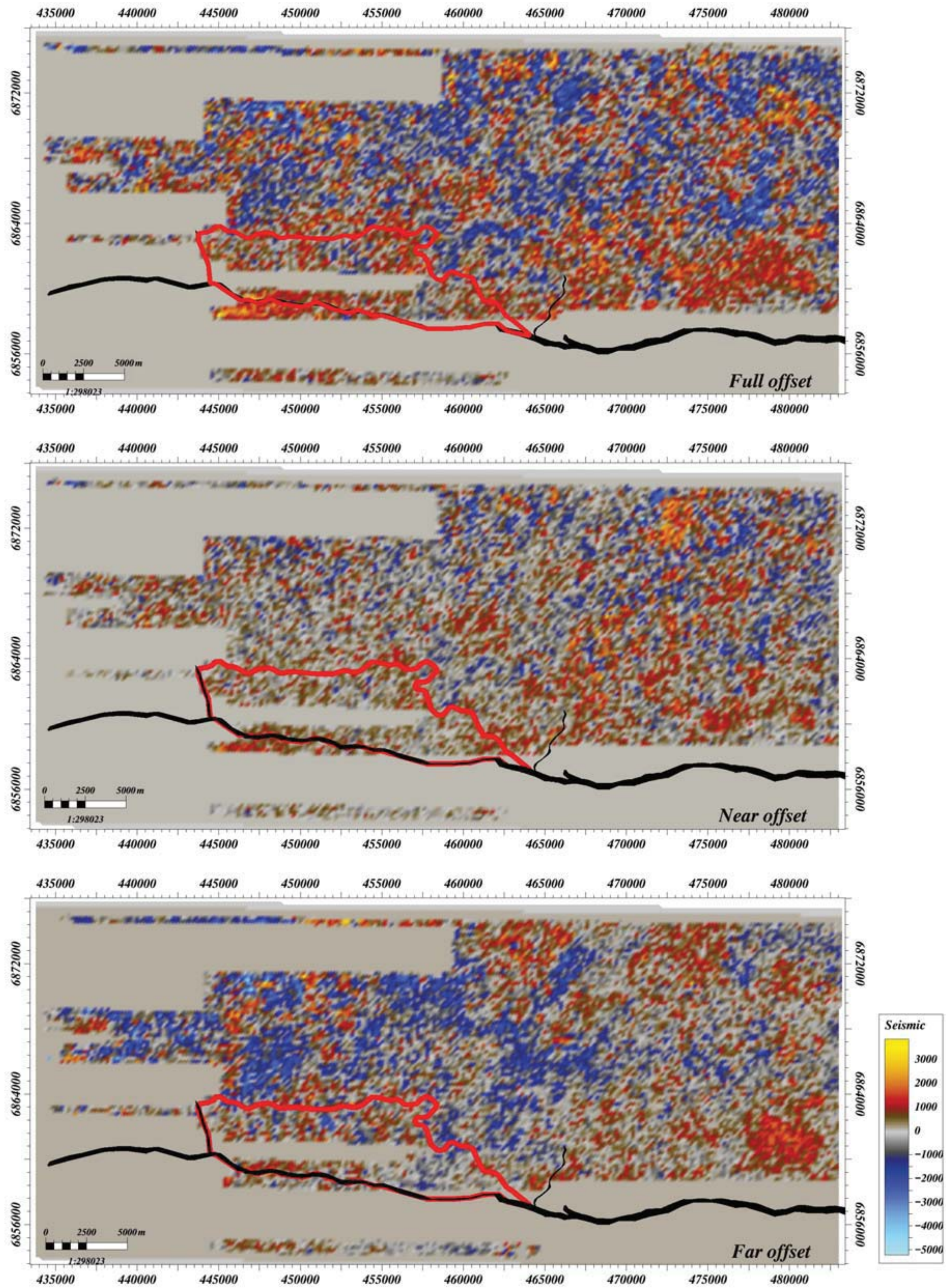


Figure 4.17 RMS Amplitude Extraction at Top Lista Seismic Marker, at Full-, Near- and Far offsets. No evident features and/or patterns referable to depositional systems can be interpreted from seismic amplitude anomalies within the Lagen Prospect (red outline) area.

It should be noted, however, that the presence of shallow gas in the overburden makes any interpretation of such seismic attributes uncertain, Figure 4.18.

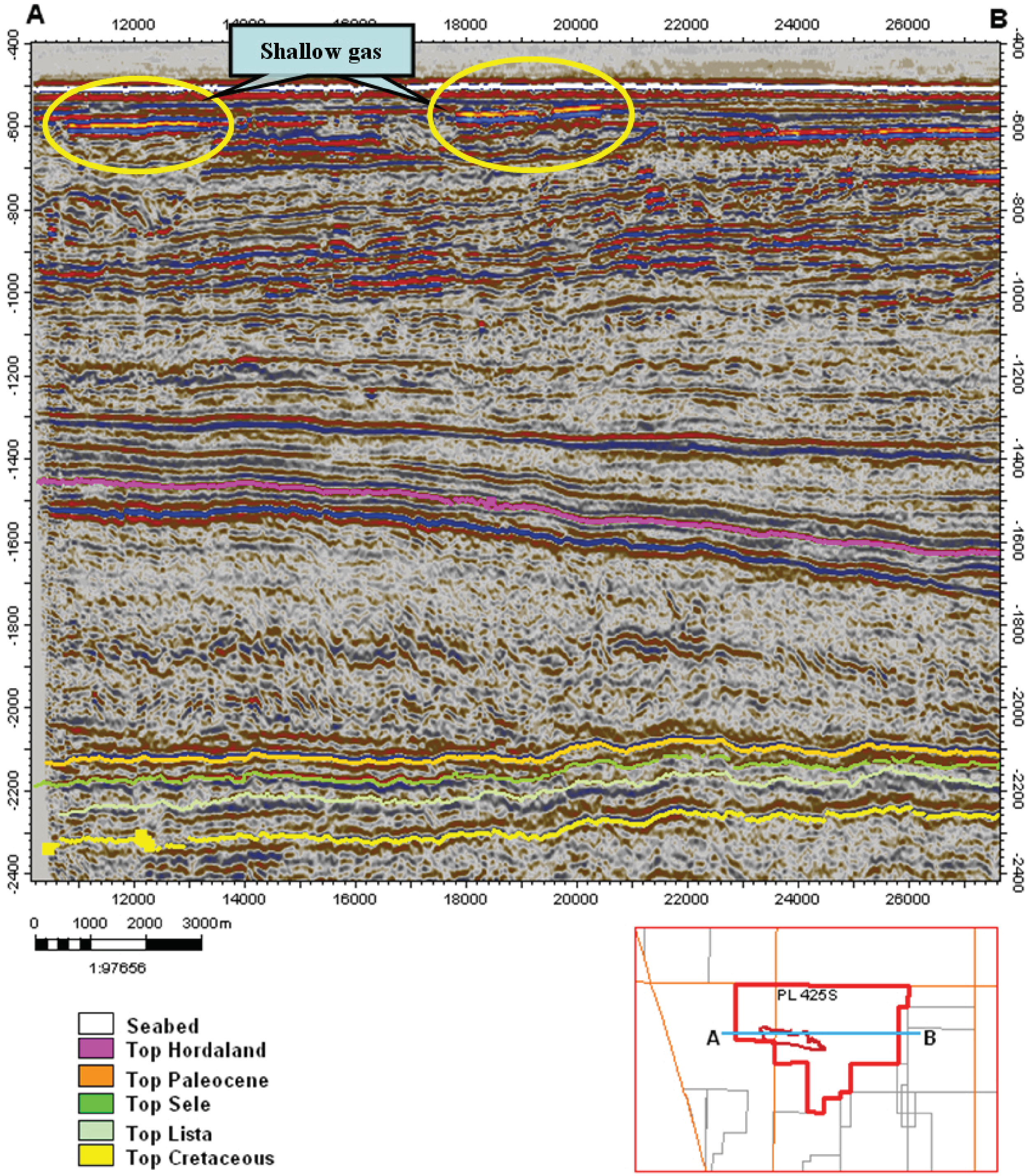


Figure 4.18 Shallow gas in overburden.

Variance cube

A variance cube was generated from the 3D pc07n023 survey for the purpose of identifying seismic facies and/or patterns that could be related to sedimentary features. The amplitude features observed on time slices seem only to correspond to faults, Figure 4.19. No other features, such as channel- or fan geometries are recognized.

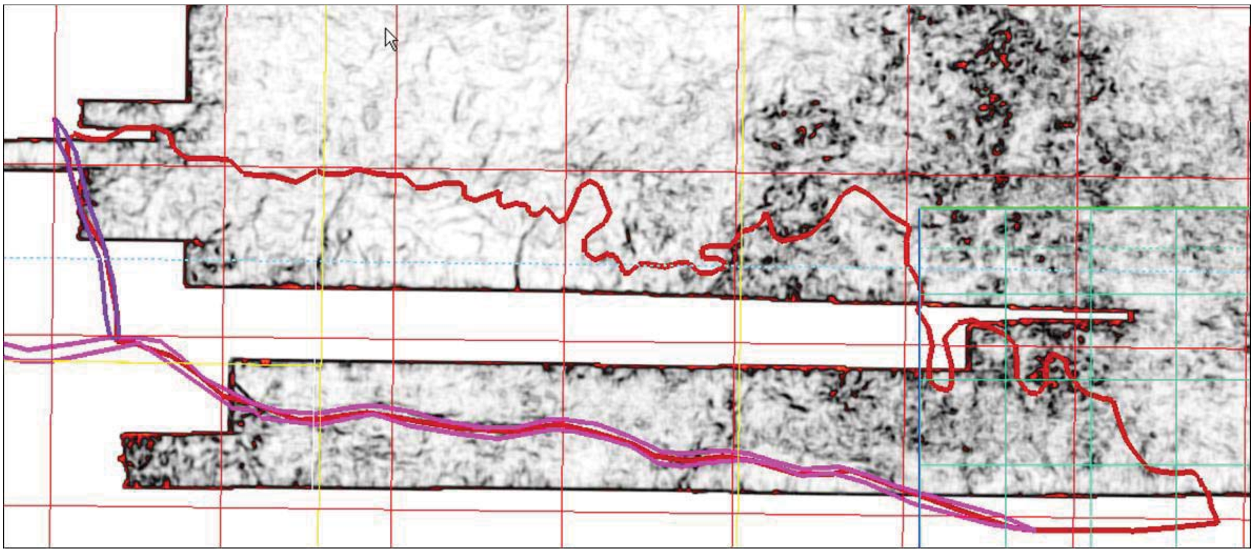


Figure 4.19 Variance Cube Time Slice (-2168 msec). This time slice within the Paleocene section shows no evident features that can be interpreted as depositional patterns. The north to south thin and dark areas are small faults. The noisy area to the east represents data disturbance from shallow gas in the overburden.

Rock Physics/Seismic Modelling

The seismic response over the Lagen prospect was modelled using both water- and hydrocarbon-bearing sands. However, the lack of offset well data did not allow for validation of these models, Figure 4.20. A discrimination between sands and shales, based on elastic properties, is also problematic, due to lack of shear sonic data.

There is also little evidence for structurally conformable amplitude variations that could be interpreted as a hydrocarbon accumulation.

Inversion study

A relative acoustic impedance volume was produced by Western Geco for PL 425S. This seismic volume did not show any features or geometries that were indicative of sedimentary facies, Figure 4.21.

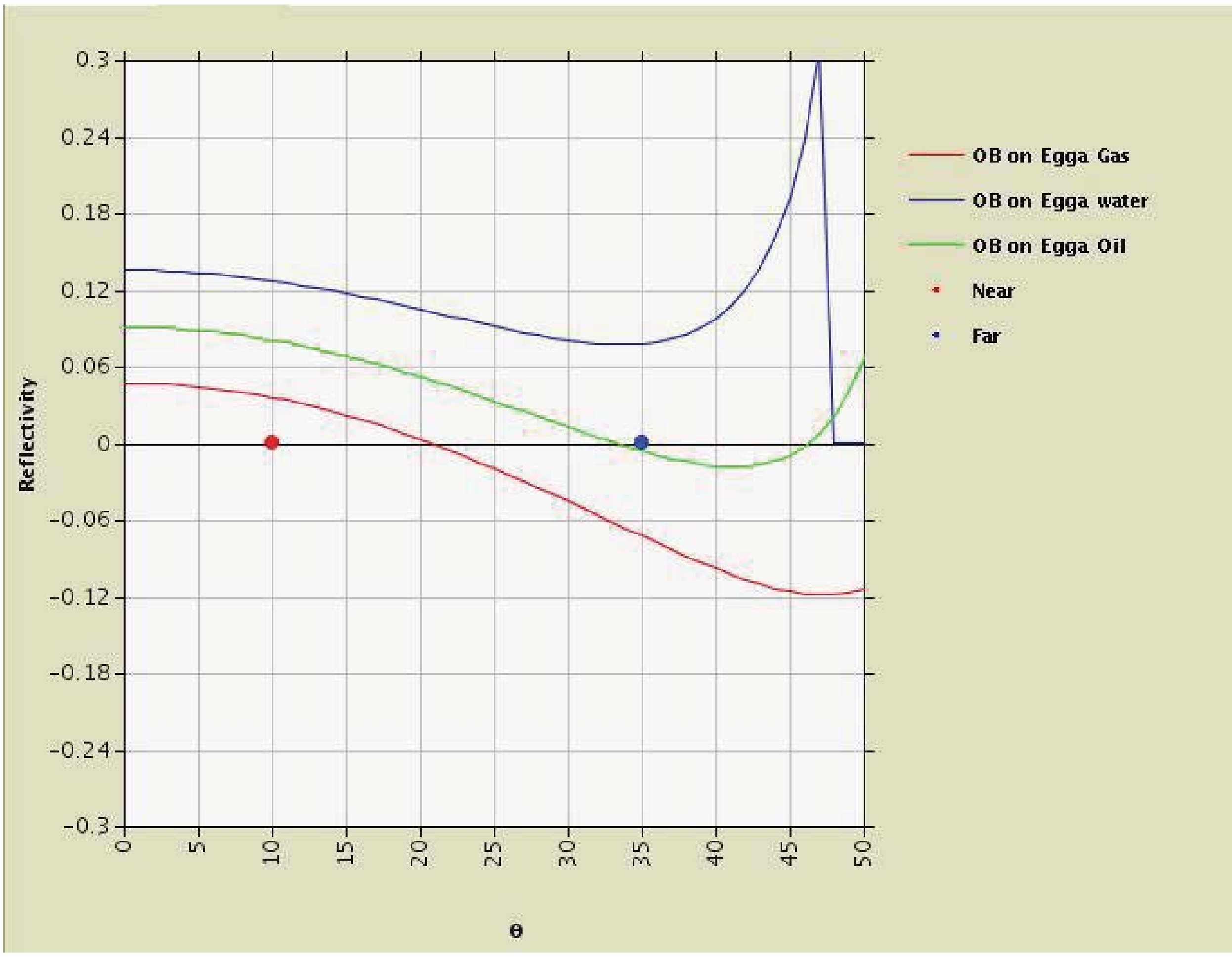


Figure 4.20 AVO Modelling.

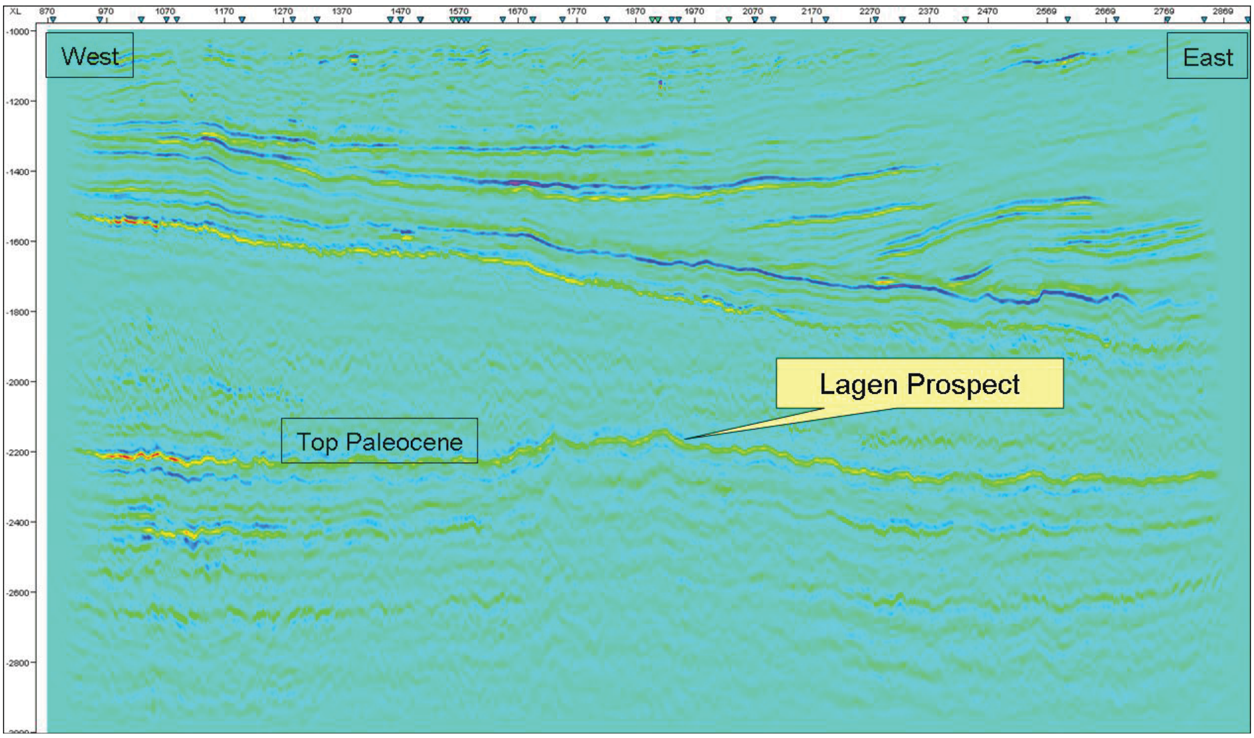


Figure 4.21 Acoustic Impedance Line over Lagen Prospect.

Conclusion

Geophysical special studies carried out in this evaluation have proven inconclusive both to address the main risk of presence of viable Paleocene sand reservoirs as well as presence of hydrocarbons within the Lagen prospect.

4.4 Reserve and Risk Estimate

Reserves for both Lagen Sele and Lagen Lista prospects have been calculated using the REP Software.

Prospect Lagen Lista

Table 4.2: Input to reserve calculation for prospect Lagen Lista.

GRV	The estimate is based on an area-depth curve and a variable gross reservoir thickness from 10 m to 85 m, as well as on a variable spill point (2000-2040 m). Note that in Table 4.2 Depth to Base refers to a possible maximum spill point.
Net to Gross	From known Tertiary reservoirs in the North Sea and Norwegian Sea.
Porosity	From known Tertiary reservoirs in the North Sea and Norwegian Sea.
Sw	From known Tertiary hydrocarbon accumulations.
FVFo	Calculated by assuming a depth of 2100 m, a temperature of 85°C and a hydrostatic pressure of 200 bar.
Oil Recovery Factor	Calculated by assuming a Bo of 1.26/1.29 rb/stb, an oil viscosity of 0.79/0.74 cps, and a GOR of 550 scf/stb.

Table 4.3. Prospect Lagen Lista.

Petro-Canada - Prospect Evaluation

Prospect

Country:	Norway	Block:	33/3, 34/1, 34/2 & 34/4
Prospect Name:	LagenLista	PetCan Equity:	60.00%
Hydrocarbon Type:	Oil	Depth Datum:	Mean sea level
Reference Map:			
File:	c:\documents and settings\cecchi\desktop\licenses\pl425s\mclagenlistanov2008.ppr		
Author(s):	User Name	Date:	16/01/09

Most Likely Geological Model

Reservoir:	Lista		
Depth to crest:	1935 m	Gross thickness:	50.0 m
Depth to base:	2100 m	Reservoir pressure:	345 bar
Column height:	165 m	Reservoir temperature:	85.0 degC
Trap area:	70.0 sq.km	Oil gravity:	35.0 deg
Trap type:	Tectonic; Extensional		

Permutated Input Parameters

Variable	Unit	Shape	Min	P90	P50	P10	Max	Mode
Area	km2	Lognor	3.50	12.5	32.3	83.4	[95.0]	18.7
Thickness	m	Lognor	7.90	20.0	40.0	80.0	[90.0]	29.9
Shape factor	%	Single	100	100	100	100	100	100
Deg. of fill	%	Single	100	100	100	100	100	100
Net-to-gross	%	Lognor	15.5	30.0	49.0	80.0	[90.0]	42.3
Porosity	%	Lognor	21.1	24.3	27.0	30.0	34.6	26.8
Sw	%	Lognor	7.77	15.0	24.5	40.0	77.2	21.2
FVF (Bo)	rb/stb	Normal	1.19	1.23	1.26	1.29	1.33	1.26
Oil rec fac	%	Normal	16.6	30.0	40.0	50.0	63.4	40.0

Possibility of Finding Hydrocarbons

Trap:	80%
Seal:	40%
Reservoir:	30%
Charge:	100%

Chance of Geological Success: 9.6%
Chance of Economic Success: 9.6%

The Chance of Success is the probability of discovering at least the minimum (P100) volume

Potential and Probability

	P100	P90	P50	P10	ML Det.
Oil-in-Place [mmcm]:	0.155	24.5	81.1	243	102
Recoverable Oil [mmcm]:	0.0258	9.39	31.7	98.4	40.9
Chance of occurrence [%]	9.60	8.64	4.80	0.960	3.76

The above volumes are whole trap (100%) values
The production interest is 60.00%

5.20e3

Prospect Lagen Sele

Table 4.4: Input to reserve calculation for prospect Lagen Sele.

GRV	The estimate is based on an area-depth curve defined by top and base of reservoir, as well as on a variable spill point (2000-2040 m).Note that in Table 4.3 Depth to Base refers to a possible maximum spill point.
Net to Gross	From known Tertiary reservoirs in the North Sea and Norwegian Sea.
Porosity	From known Tertiary reservoirs in the North Sea and Norwegian Sea.
Sw	From known Tertiary hydrocarbon accumulations.
FVFo	Calculated by assuming a depth of 2100 m, a temperature of 85°C and a hydrostatic pressure of 200 bar.
Oil Recovery Factor	Calculated by assuming a Bo of 1.26/12.29 rb/stb, an oil viscosity of 0.79/0.74 cps, and a GOR of 550 scf/stb.

Table 4.5. Prospect Lagen Sele.

Petro-Canada - Prospect Evaluation

Prospect

Country:	Norway	Block:	33/3, 34/1, 34/2 & 34/4
Prospect Name:	LagenSele	PetCan Equity:	60.00%
Hydrocarbon Type:	Oil	Depth Datum:	Mean sea level
Reference Map:			
File:	c:\documents and settings\cecchi\desktop\licenses\pl425s\mclagennov2008.ppr		
Author(s):	User Name	Date:	16/01/09

Most Likely Geological Model

Reservoir:	Sele		
Depth to crest:	1935 m	Gross thickness:	50.0 m
Depth to base:	2100 m	Reservoir pressure:	345 bar
Column height:	165 m	Reservoir temperature:	85.0 degC
Trap area:	70.0 sq.km	Oil gravity:	35.0 deg
Trap type:	Tectonic; Extensional		

Permutated Input Parameters

Variable	Unit	Shape	Min	P90	P50	P10	Max	Mode
Spill point	m	Normal	1973	2000	2020	2040	2067	2020
Deg. of fill	%	Single	100	100	100	100	100	100
Net-to-gross	%	Lognor	15.5	30.0	49.0	80.0	[100]	42.3
Porosity	%	Lognor	21.1	24.3	27.0	30.0	34.6	26.8
Sw	%	Lognor	7.77	15.0	24.5	40.0	77.2	21.2
FVF (Bo)	rb/stb	Normal	1.19	1.23	1.26	1.29	1.33	1.26
Oil rec fac	%	Normal	16.6	30.0	40.0	50.0	63.4	40.0

Possibility of Finding Hydrocarbons

Trap:	80%
Seal:	40%
Reservoir:	30%
Charge:	100%

Chance of Geological Success: 9.6%
Chance of Economic Success: 9.6%

The Chance of Success is the probability of discovering at least the minimum (P100) volume

Potential and Probability

	P100	P90	P50	P10	ML Det.
Oil-in-Place [mmcm]:	0.484	19.6	50.4	120	54.0
Recoverable Oil [mmcm]:	0.0804	7.34	19.8	49.2	21.6
Chance of occurrence [%]	9.60	8.64	4.80	0.960	4.36

The above volumes are whole trap (100%) values
The production interest is 60.00%

5.20e3

Chance of Success (COS)

Chance of Success (COS) - 9,6% for both Top Sele Prospect and Top Lista Prospect.

Trap P(1) - 80%
As discussed in 4.1 Seismic Interpretation and Depth Conversion, seismic interpretation is base on 3D seismic data of good quality and resolution. The seismic horizons defining the prospects have good continuity and are easily mappable.

Seal (P2) - 40%
As discussed in 4.2 Lagen Prospect, lateral seal effectiveness is considered at risk because of the juxtaposition of potential sandstones across the prospect bounding faults.

Reservoir (P3) - 30%
As discussed in 4.2 Lagen Prospect, presence of viable Paleocene sandy reservoirs is the main risk for both Lagen Sele- as well as for the Lagen Lista prospect.

Charge (P4) - 100%
As discussed in 3.5 Source Rock Quality, Charge and Hydrocarbon Phase, presence and effectiveness of the Upper Jurassic source rock, as well as hydrocarbon charge are not considered risk elements for the prospects.

4.5 Other Leads in Acreage

In addition to the Lagen prospect(s), three seismic amplitude anomalies at the Cretaceous - Tertiary boundary have been mapped within the PL 425S acreage, Figure 4.22. These anomalies are interpreted to represent lithological changes within limestone/shale intervals of the Jorsalfare Formation. Trap mechanism is stratigraphic with potential reservoirs of chalk facies analogous to those encountered at the Tulipan Discovery Well 6302/6-1.

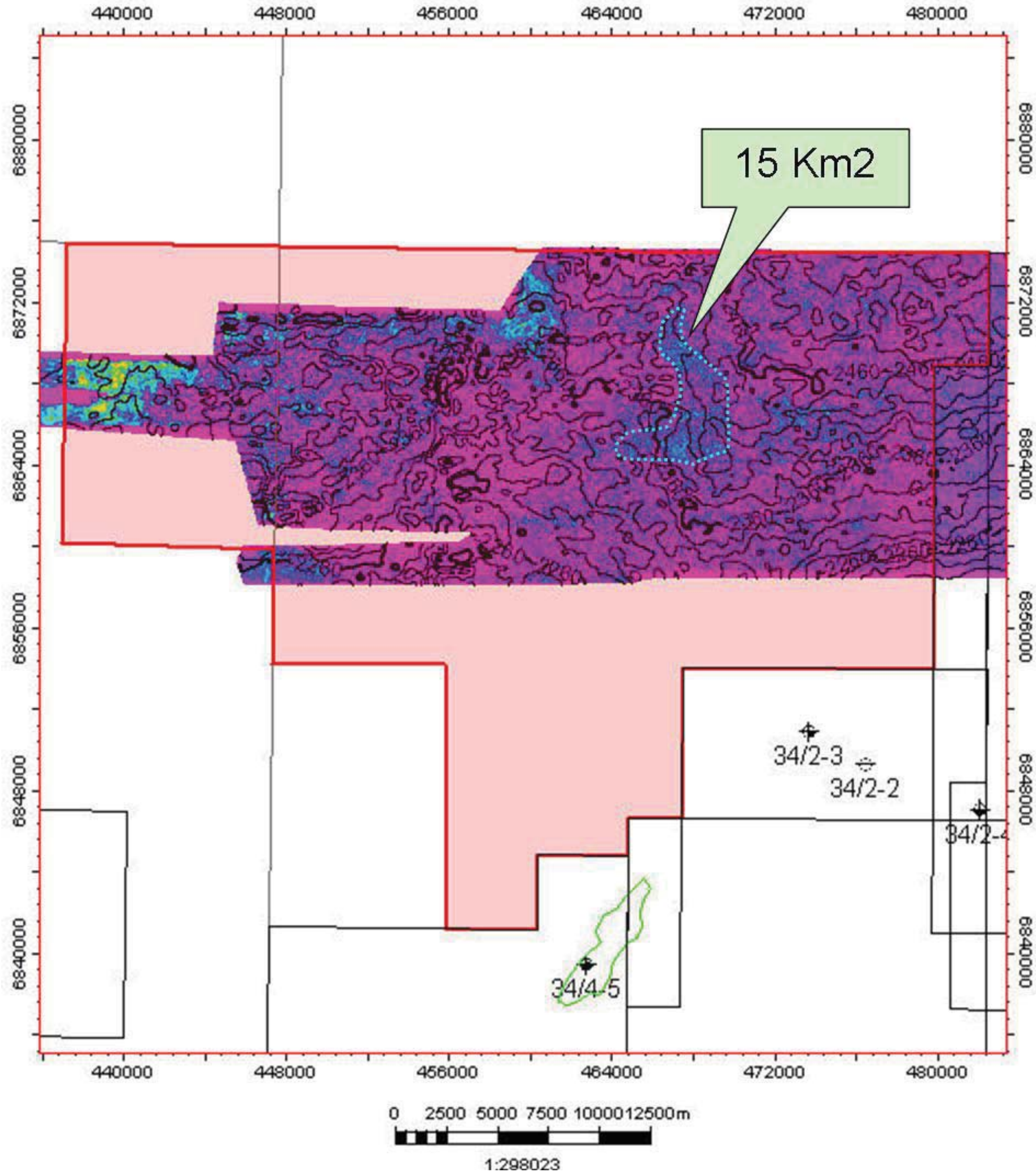


Figure 4.22 RMS Seismic Amplitude Anomalies at the K/T Boundary, PL 425S. Amplitude extraction (RMS, +-10 msec at Top Cretaceous Seismic Horizon) from 3D volumes reveals patches of relative amplitude increase. These patches are interpreted by Petro-Canada to represent lithological variations within the shale-limestone units of the Jorsalfare Formation.

The largest mappable anomaly in the area covers an area of 15 km^2, with estimated resources of 2 mm standard cubic meters recoverable oil and with a chance of success (COS) of 5 %, where trap and effective reservoir presence are considered as the main risks.

Petro-Canada regards the possibility that these seismic anomalies would represent sandy reservoirs with hydrocarbons as unlikely. RMS amplitude maps at the K/T boundary from the Snorre Area to the south also show similar seismic features. However, neither sands nor hydrocarbons were proven by the wells drilled through these seismic amplitude anomalies.

5 Conclusions

The specified work obligation in PL 425S was fulfilled during the two year license period: This included acquisition and purchase of 3D seismic surveys. In addition, reprocessing of selected 2D seismic data was also carried out.

The licensees have agreed that the recognised prospects on PL 425s are not material. Consequently, the PL 425S partnership formally notifies NPD of the Groups' relinquishment of the license.

6 References

Ziad, A. et al., 2003. The Paleocene. In: The Millennium Atlas, Petroleum Geology of the Central and Northern North Sea. Evans, D., Graham, C., Armour, A. and Bathurst, P., Eds., London Geological Society Publ..

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