PL531 RELINQUISHMENT REPORT

Repsol Exploration Norge AS

7/1/2014

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1. Key licence history

The PL531 licence was awarded the 15th of May 2009 in the 20th bidding round. The initial period was valid until the 15th of May of 2014. The original partnership was composed of: Marathon Petroleum Norge AS (30% Operator), Talisman Energy Norge AS (25%), RWE Dea Norge AS (25%), Concedo AS (20%).

On the 31st of November 2011 Repsol Exploration Norge took over 20% from Marathon Oil Norge AS as well as the licence operatorship. On the 1st of January 2012, Det Norske Oljeselskap ASA acquired 10% of RWE Dea Norge AS shares. The last change in the partnership was on the 30th of November 2012 when Faroe Petroleum Norge AS took over 12.5% of Talisman Energy Norge AS shares.

The licensees, at the time of the relinquishment, were:

Repsol Exploration Norge AS	20% (operator)
Concedo AS	20%
RWE Dea Norge AS	15%
Talisman Energy Norge AS	12.5%
Faroe Petroleum Norge AS	12.5%
Marathon Oil Norge AS	10%
Det Norske Oljeselskap ASA	10%

The licence work obligations had been fulfilled by the end of the first exploration period:

- <u>Reprocess 3D seismic in the area of the licence</u>. The licence partners purchased the 3D PreSDM and PreSTM reprocessed in 2008 by WG for Total and the WG1001 3D survey.
- <u>Drill a well to either 100m in to the Kobbe Formation or to 4000m before the 15th of May of 2013</u>. Well 7218/11-1 (Darwin) was spudded on the 4th of March 2013 reaching TD (2500m TVDSS) on the 2nd of April 2013. Based on the studies carried out on the licence prior to the drilling, it was identified that a shallower well was able to test the primary prospectivity of the licence and determine the stratigraphy of the Veslemøy High. Consequently, NPD approved on the 22nd of August 2011, the licence application to drill a well to either 100m in to the Kobbe Formation or to a depth of 2500m instead of the original 4000m.

Well 7218/11-1 failed to find either hydrocarbons or reservoir in any of the target zones. Recently, north of PL531, in PL609 licence, 7218/8-1 (Byrkje) well was drilled with similar results as 7218/11-1 well. The negatives results from Darwin together with the lack of reservoirs, both in the 7218/8-1 and 7218/11-1S wells, triggered the decision to not extend the first exploration period and consequently relinquish the P531 licence.

2. Database

2.1 Seismic Database

The seismic coverage of the licence is listed in and shown in Fig. 2.1.

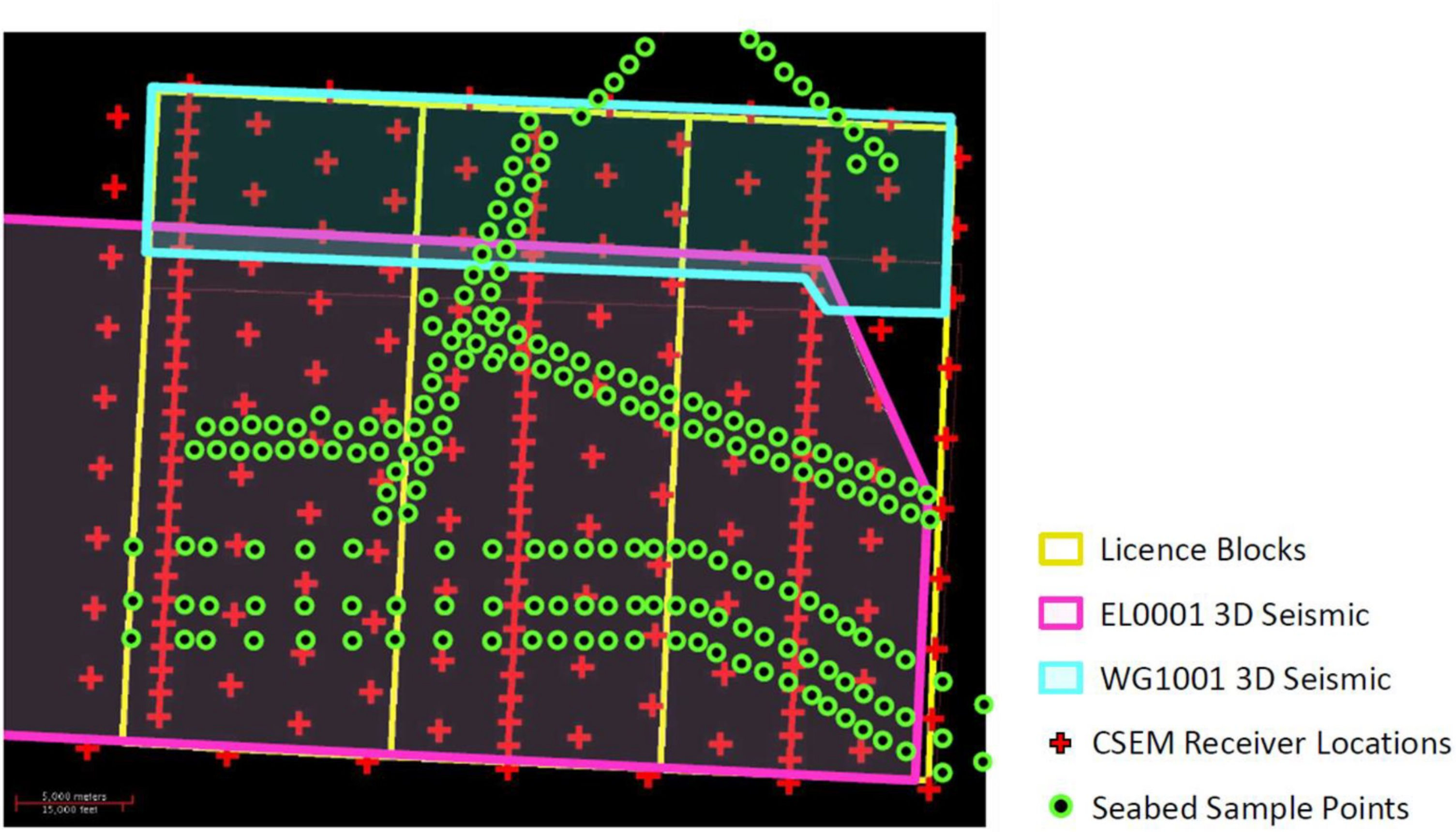


Figure 2.1 PL531 database

The 3D surveys EL0001 and NH9803 are public. The licence purchased the WG1001 3D survey and the EL0001 PreSTM & PreSDM 3D surveys, reprocessed by WG in 2008. Additionally, 2D lines were added to the database to have a better understanding of the regional framework.

2.2 Well database

Figure 3.1 shows the wells included in the database for licence PL531. The wells are also presented in Table 2.1, which includes information about the year drilled, status, hydrocarbon shows and reservoir presence. Wells 7218/11-1 (Darwin) and 7218/8-1 (Byrkje) are new wells which were drilled during the exploration period.

Wells	Year drilled	Status	HC shows	Reservoir
7218/11-1	**2013**	**Dry**	**Gas**	**No reservoir**
7218/8-1	**2014**	**Dry**	**Gas**	**No reservoir**
7216/11-1S	2000	Dry	No shows	Eocene Torsk
7219/8-1	1992	Dry	Traces	Jurassic Stø
7219/9-1	1988	Dry	Oil	Jurassic Stø& Nordmela, Triassic Tubåen
7117/9-1	1982	Dry	Oil Traces	Oligocene to Eocene Torsk
7117/9-2	1983	Dry	No shows	No reservoir

Table 2.1 Wells database

2.3 Special studies

Several special studies have been carried out by the licence PL531, both in-house and by external parties. These studies include (see figure 2.1):

- EM data: EMGS BSMC08Q survey which was inverted in 2009 by EMGS and also by Geosystems. The EM data was also inverted in 2013 after the drilling of well 7218/11-1
- Geochemical/microbiological seabed surveys: MicroPro GmbH 2008 and 2010 surveys from Gore.

3 Review of geological framework

Licence PL531 is located on the southern portion of the Veslemøy High. The Veslemøy High is located in the western most portion of the Barents Sea, in-between the Tromsø Basin to the SE, and the Sørvestsnaget and Bjørnøya basins to the NW (Figure 3.1). It actually is a paleo-high, active during the latest Cretaceous and earliest Tertiary.

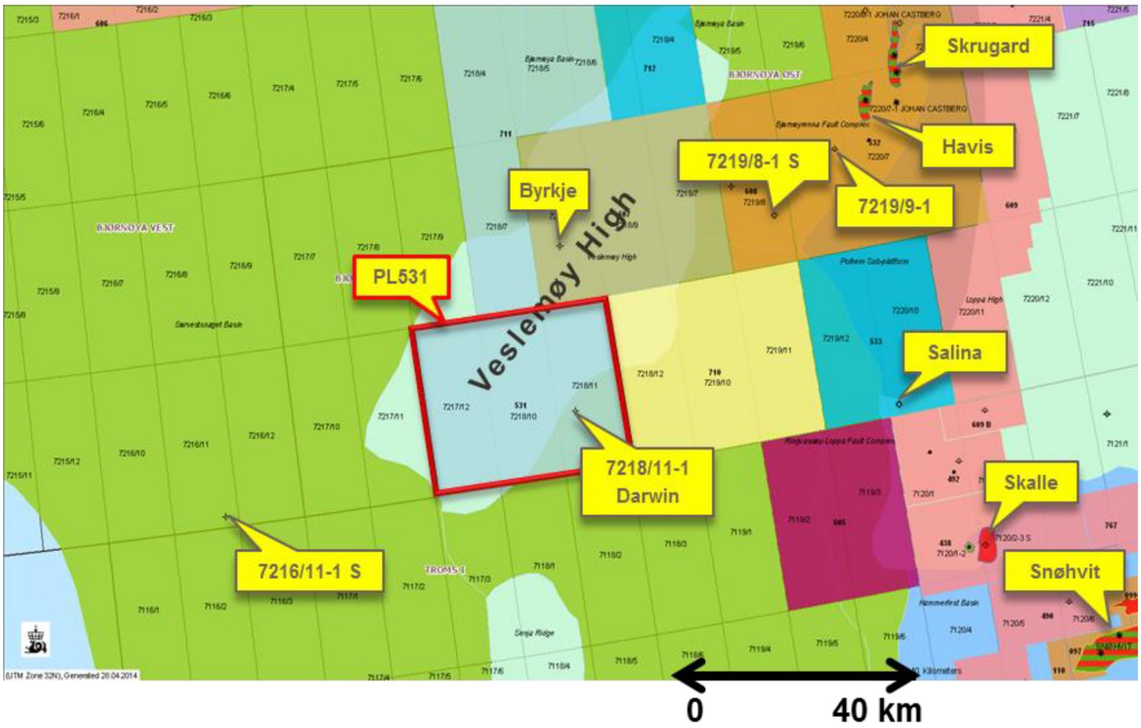


Figure 3.1 PL531 Location map

The Cretaceous section in the Veslemøy High consists of a series of faulted blocks developed by a listric fault system possibly rooted in the lower most Cretaceous section. After the breakup of Scandinavia and Greenland, the western most Barents Sea became a passive margin characterised by prograding sedimentation during Tertiary and Quaternary times. The Cretaceous and Tertiary megasequences are separated by a major unconformity, the Base Tertiary Unconformity (BTU). In the Veslemøy High, this unconformity is clearly angular, reflecting uplift due to localised compressional conditions (see Figure 3.2).

The two main plays considered in PL531 were:

- *Cretaceous* turbidite sandstones trapped in halfgrabens underneath the BTU.
- *Paleocene turbidites sandstones*

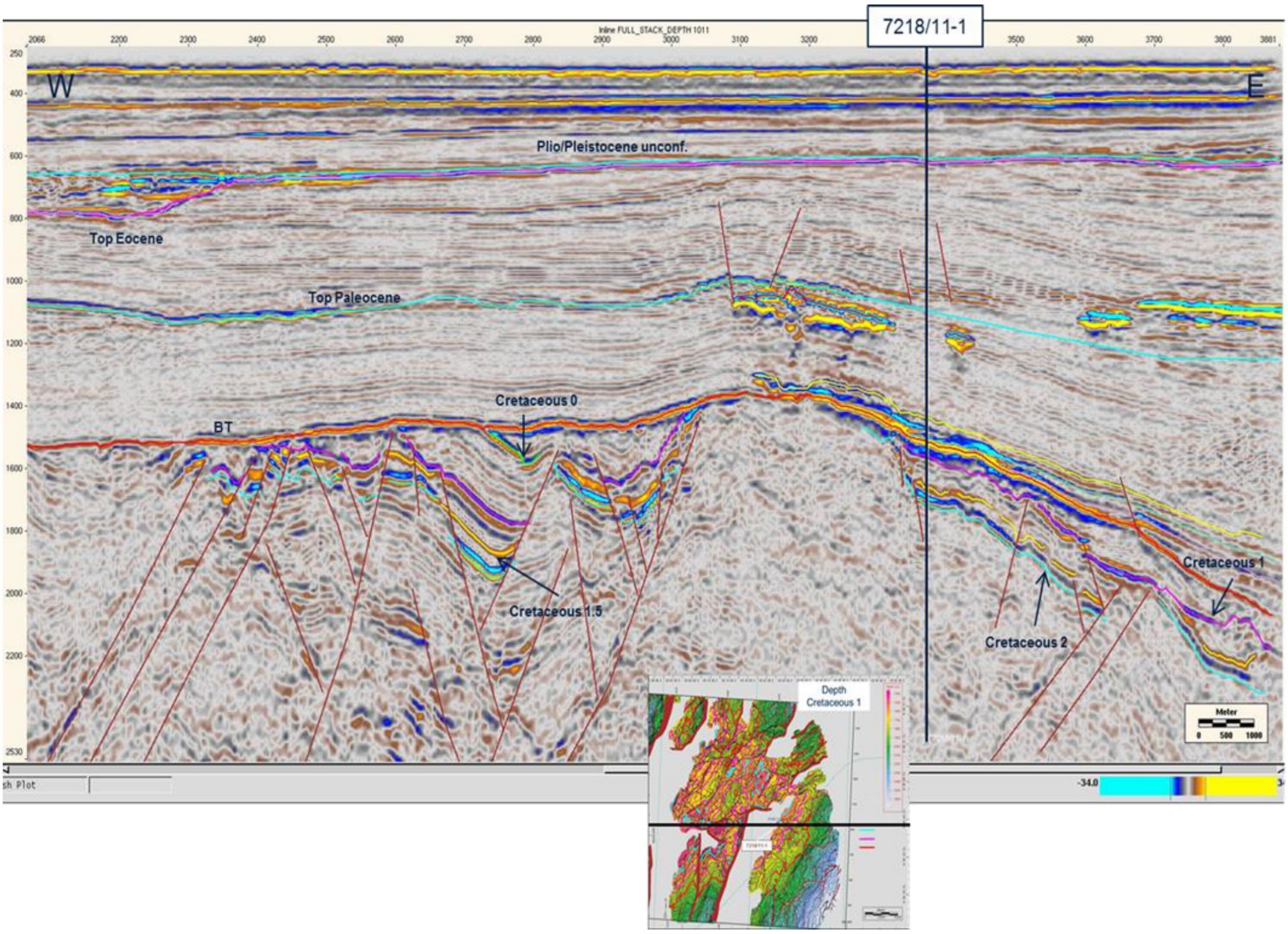


Figure 3.2 Seismic line along the Veslemøy High

A series of studies were carried out in order to de-risk both the Cretaceous and the Paleocene play:

1. Seismic inversion, AVO and seismic attributes analysis

On top of the BTU an amplitude anomaly was identified. It was composed by a series of vertical stacked reflectors onlapping onto the high. The amplitude anomaly (soft amplitude) is not consistent with the structure; however, the western flank of the anomaly is bounded by a fault which, on top of it, has a ribbon shape anomaly, possibly caused by gas leakage.

An AVO analysis and a Sparse-spike inversion were run in the EL0001 3D survey (see figure 3.3). The amplitude anomaly at the Paleocene level was observed to be class-2/class-3 with relatively low acoustic impedance. In the Cretaceous hemigrabens the Sparse-spike inversion showed an alternation of relatively low and high acoustic impedance layers.

In addition several attributes, such as spectral decomposition, amplitude related attributes and semblance were computed (figure 3.4 and 3.5). The amplitude anomaly showed a series of stacked lobes but with no clear indications of sedimentary features. Due to the intense faulting, no sedimentary features were observed in the Cretaceous hemigrabens.

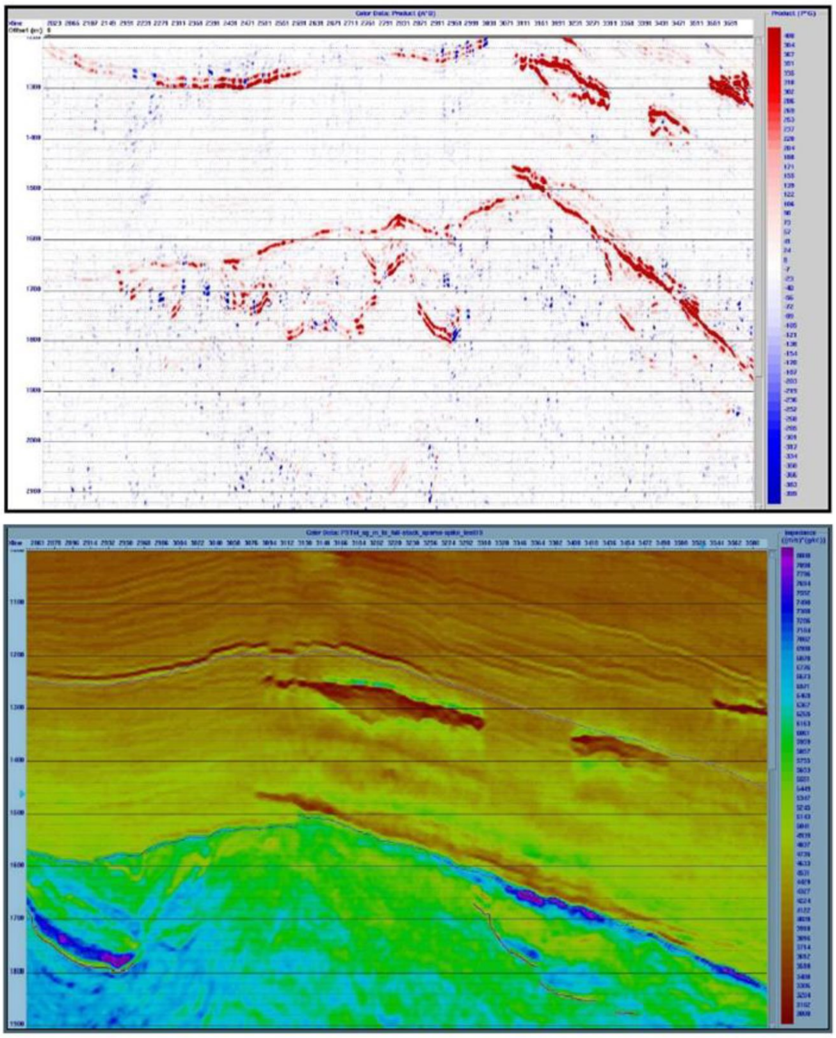


Figure 3.3 Intercept x Gradient (above) and Sparske-spike inversion (below)

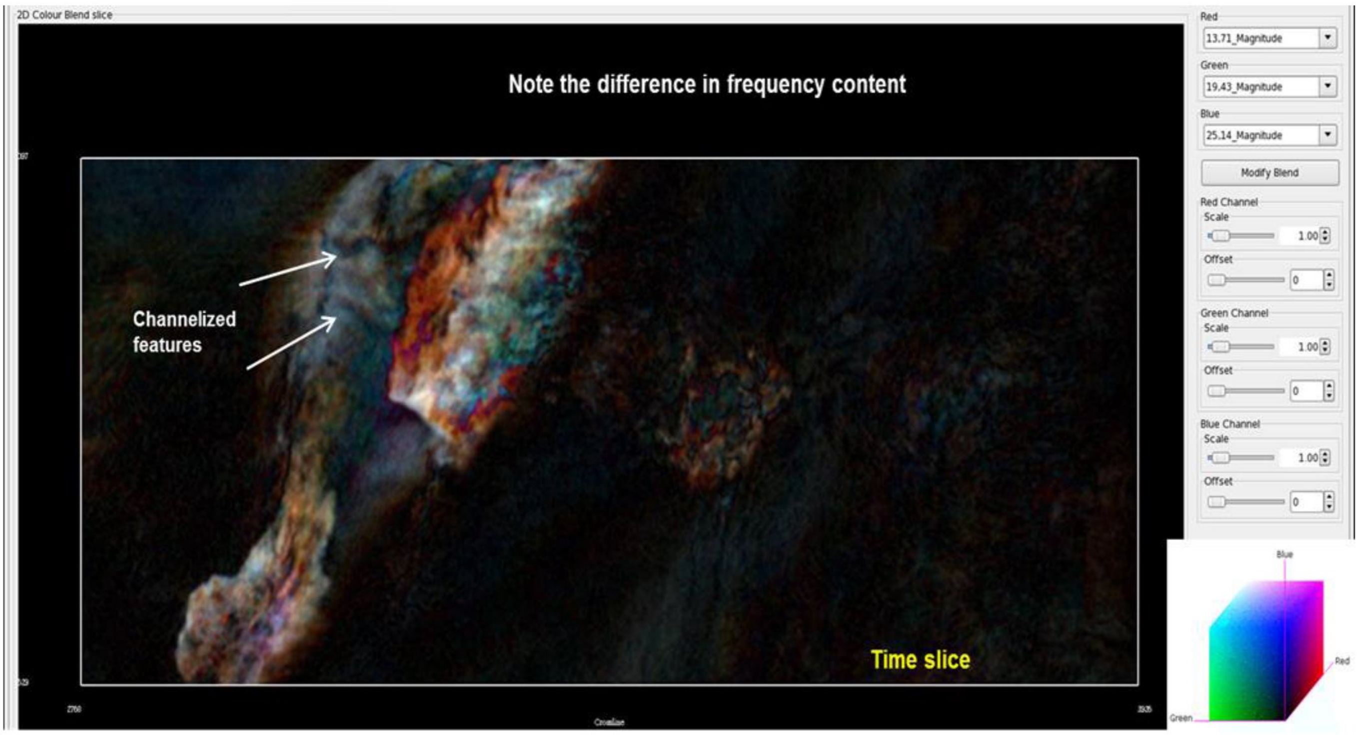


Figure 3.4 Spectral decomposition time slice along the Paleocene amplitude anomaly

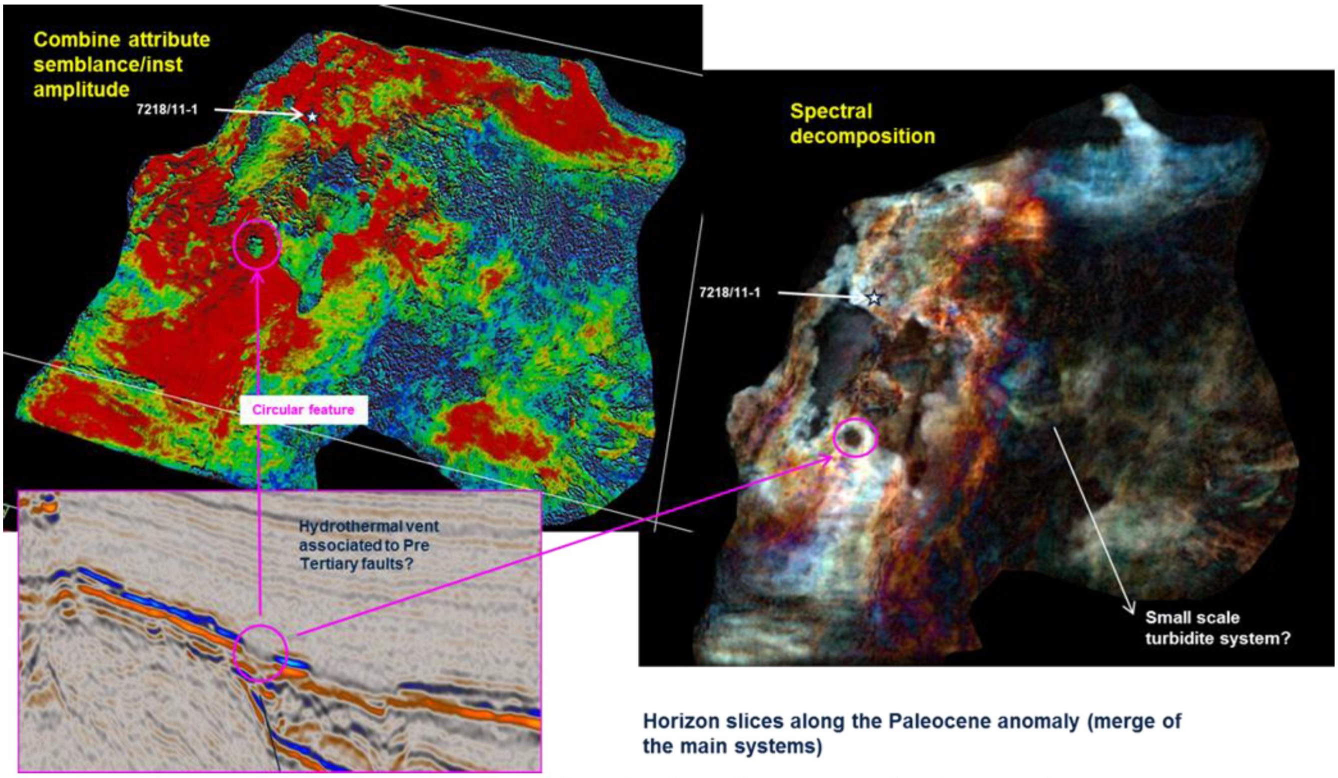


Figure 3.5 Seismic attribute analysis for the Paleocene amplitude anomaly

2. Electromagnetic Inversion

The EMGS BSMC08Q survey was acquired in 2008 for the licence application. In 2009, as part of the licence work programme, EMGS did a reprocessing and a 2.5D inversion. Additionally, in 2009 Geosystem carried out a 3D inversion of the BSMC08Q survey. [redacted]

In 2013, after the drilling of 7218/11-1 well, a reprocessing and a 3D inversion were carried out in the BSMC08Q survey. [redacted]

[redacted]

Figure 3.6 Tertiary Unconformity depth map & EMGS resistivity

2009 VS 2013 (CROSS-SECTIONS THROUGH RV)

[redacted]

Figure 3.7 Comparison between 2009 & 2013 inversion

2009 VS 2013 (RV BETWEEN TOP TERTIARY AND CRETAC2 +150M)

[redacted]

Figure 3.8 Comparison between 2009 & 2013 inversion

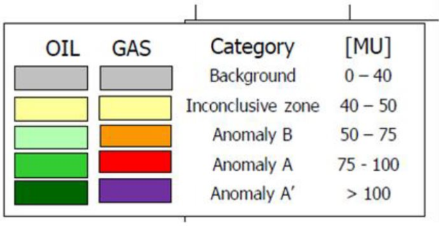
3. Geochemical/microbiological Seabed sampling

Two Geochemical/microbiological seabed sampling surveys were acquired in 2008 and 2010 respectively.

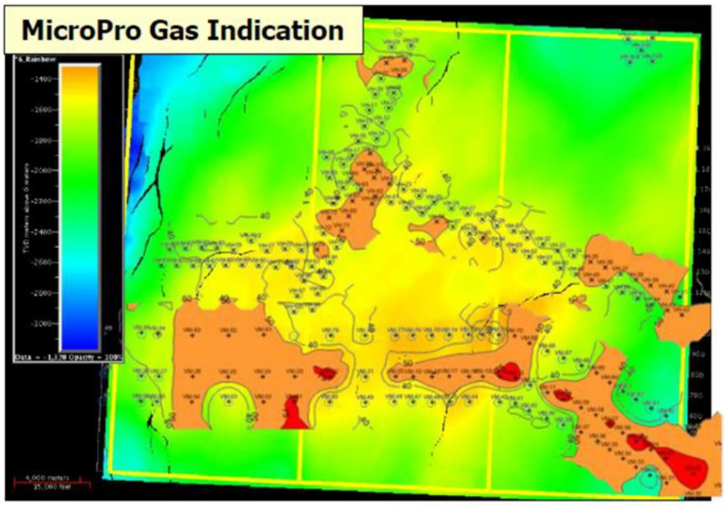
The microbial hydrocarbon signals for gas and oil are shown in figures 3.9. The conclusions were that there are both oil and gas indications with relatively high background values, indicative of a probably working hydrocarbon system. Oil indications were stronger in the central part of block 7218/10 while the strongest gas indications are located south/south east. As there were no strong and localised anomalies, the faults are potentially sealing.

The geochemical results from the seabed samples are presented in figure 3.10. They do not show a distinct pattern, maturity ranges from peak oil to early oil window (1.0 to 0.7% Ro). The liquid hydrocarbons occur as micro seepages, with widespread distribution of Type II and III kerogen extracts, suggesting a gradual seepage from mature source rocks in the area, rather than from any discrete structure.

The geochemical/microbiological results are not conclusive.



TWT Base Tertiary Unconformity



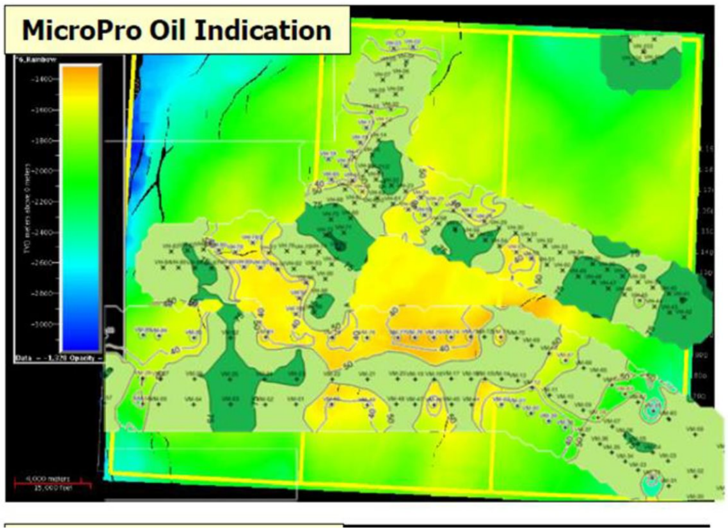


Figure 3.9 Microbial HC signal for oil (left) and gas (right)

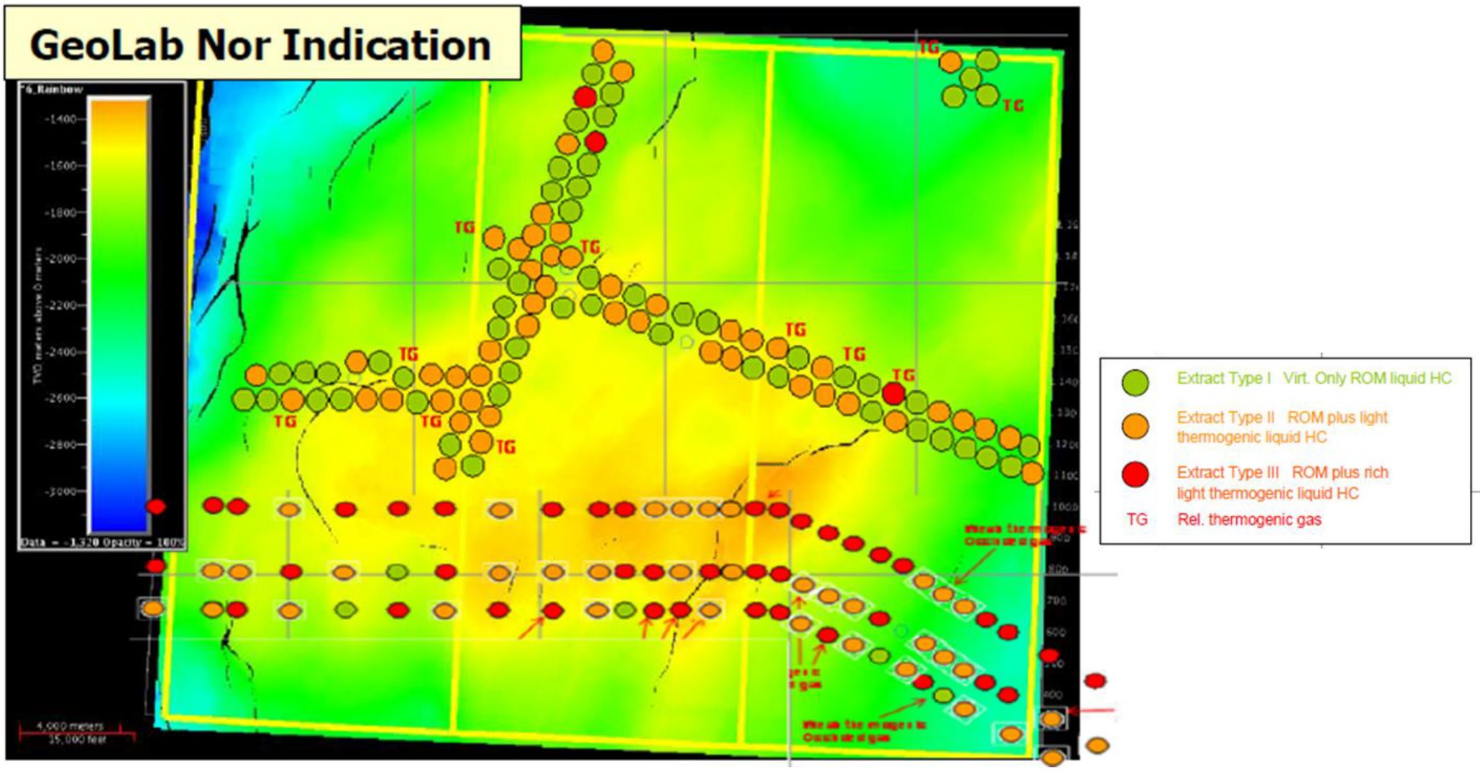


Figure 3.10 Seabed samples Geochemical results

4. Structural evolution of the Veslemøy High

Based on the seismic data, the Veslemøy High is the result of a multi-event deformation:

- Late Cretaceous syn-kinematic episode: listric shallow rooted faults affecting the early Late Cretaceous sequences on the top of the structure.
- Post-kinematic "latest Cretaceous" event, resulting in general truncation of the BTU throughout the anticline
- Early Paleocene syn-kinematic episode: progressive onlapping of Lower Paleocene strata on the eastern limb of the structure.
- Late Paleocene post-kinematic episode: no activity (or very mild activity).
- Eocene syn-kinematic episode: progressive erosion of the BTU on the western limb of the structure.

Although the seismic imaging is very poor on the deeper section, it is possible to infer a probable decoupling of the pre-Tertiary structuration in the Veslemøy High (see figure 3.11 and 3.12). The pre-Tertiary section could be divided into two different rheological systems, limited by a detachment surface located slightly above the Base Cretaceous Unconformity. The Cretaceous system is characterised by heavily rotated faulted blocks and is interpreted to correspond to the "zone of tension" of a glided system, despite the fact that up to now, no clear evidence of the expected "toe compression" have been identified.

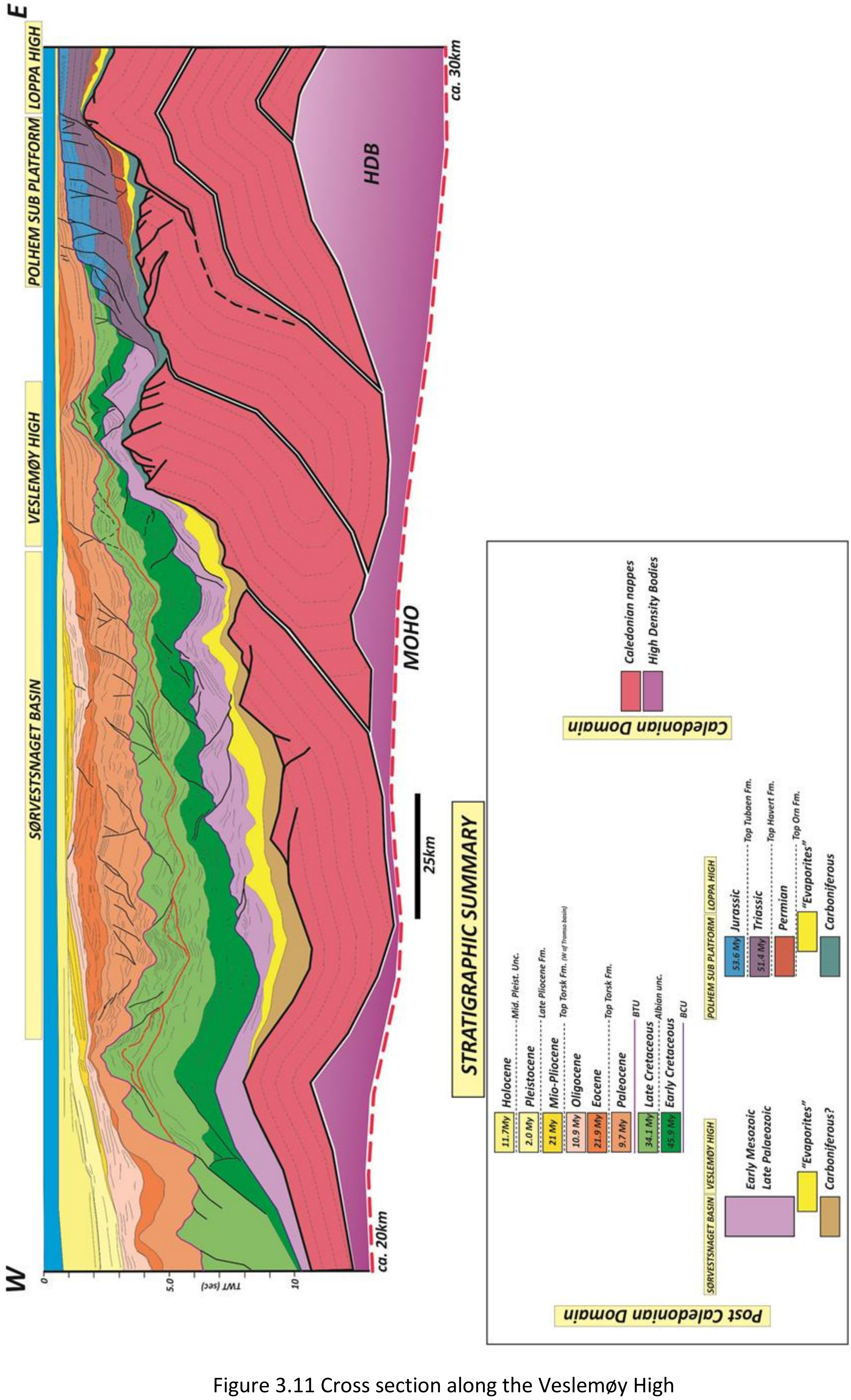


Figure 3.11 Cross section along the Veslemøy High

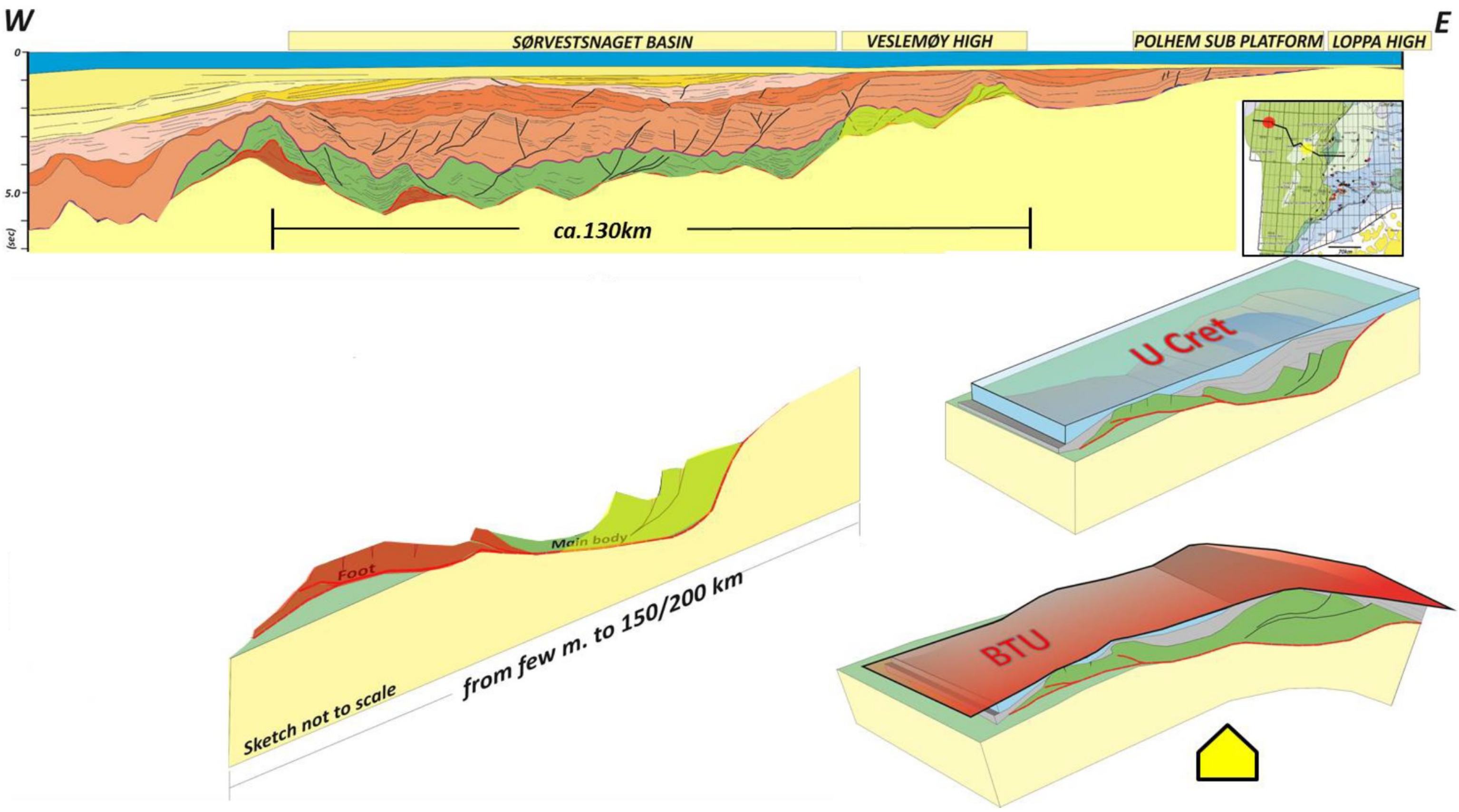


Figure 3.12 Cretaceous glided system

4 Prospect Update

At the time of the application several leads were identified in the licence (see figure 4.1 and 4.2) targeting three plays:

- Paloecene turbidites sandstones onlapping the BTU (probably sourced from the Loppa High) and Paloecene injected “pods”.
- Cretaceous turbidites sandstones deposited in halfgrabens underneath the BTU.
- Deep Jurassic Stø Fm. trapped in faulted 4-way dip closure.

As no reprocessing was carried out in the EL0001 survey (already reprocessed in 2008 by WG) there were no substantial changes made in the seismic interpretation apart from a more detailed fault interpretation at the Cretaceous level.

After a lead ranking process, the licence agreed to drill Darwin prospect, located in the south eastern portion. Here, both the Paleocene and Cretaceous plays were interpreted to be present and could be tested with one well.

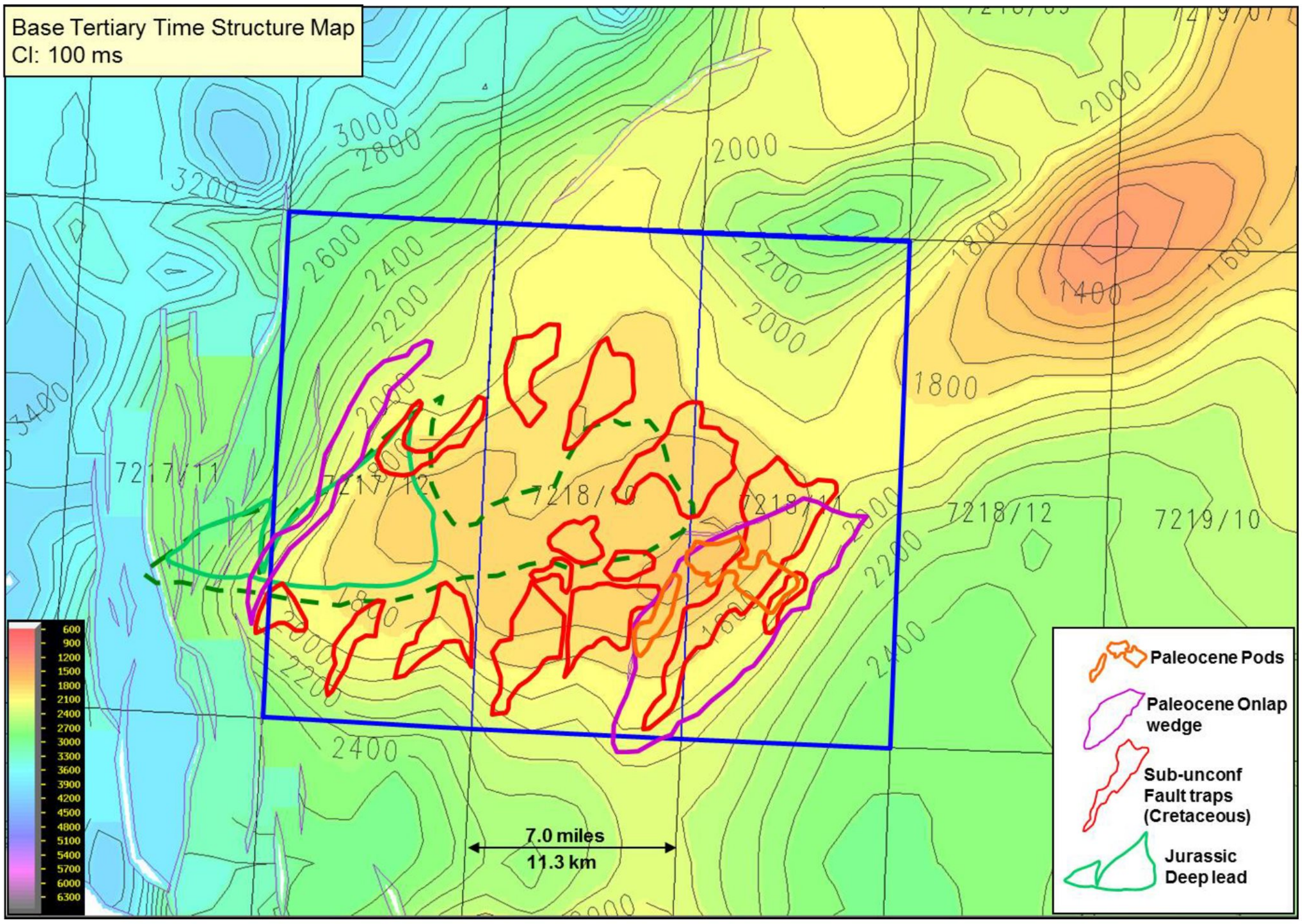


Figure 4.1 Leads identified at the time of the application

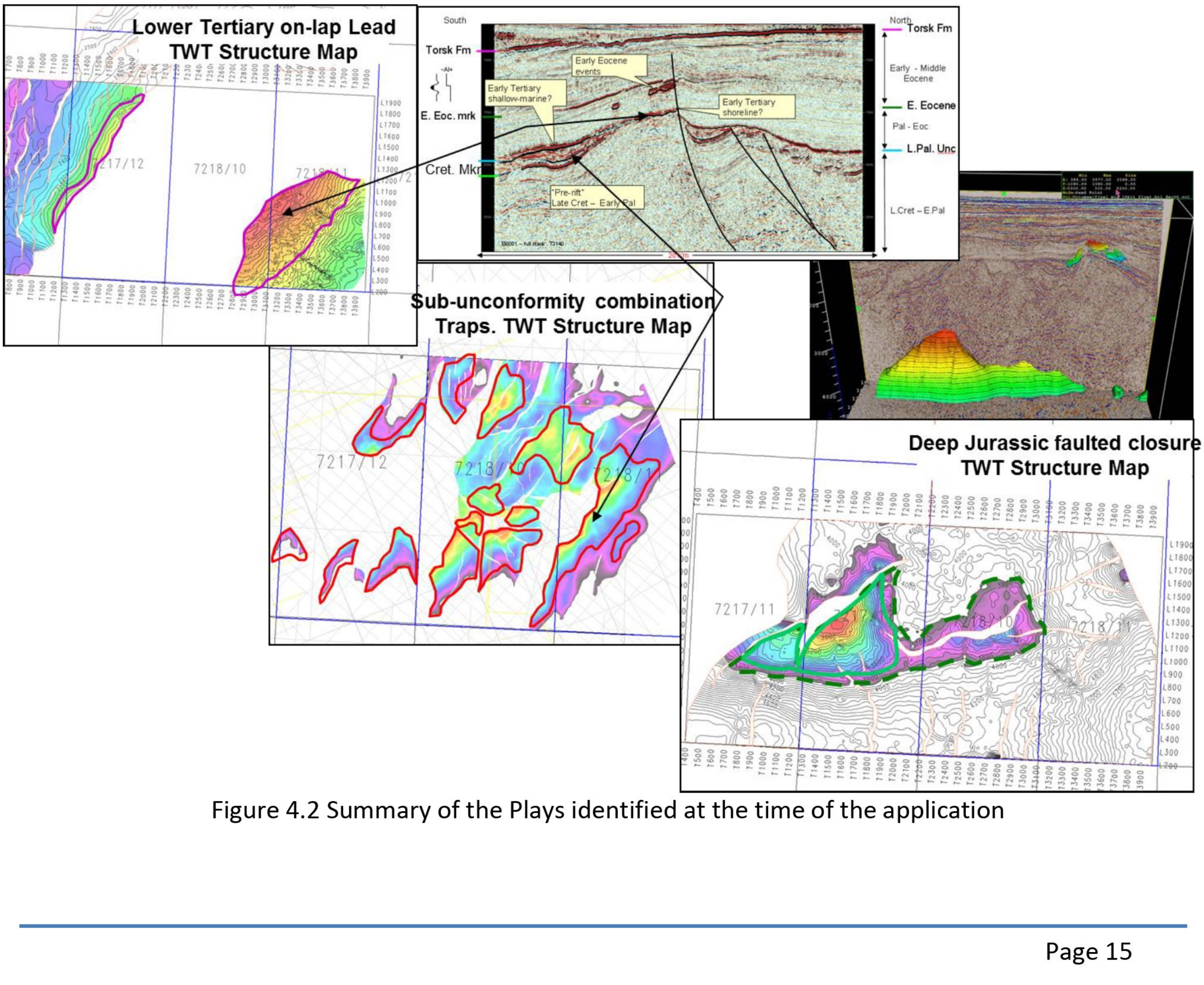


Figure 4.2 Summary of the Plays identified at the time of the application

Darwin prospect

Darwin prospect targeted two plays:

1. Paleocene beds onlapping the paleo high at the Base Tertiary Unconformity (see figure 4.3). These were considered to be probably turbidite sandstones sourced by the Loppa High. The trap is mainly stratigraphic, with a structural component in the form of a normal fault at the updip termination of the Paleocene reservoir. The beds were considered to be stratigraphically equivalent to the basal part of the Torsk Formation; their age was thought to be Paleocene. It was characterised by a low impedance amplitude anomaly bounded in its western flank by a fault. However, the amplitude anomaly was not consistent with the structure in its southern, northern and eastern flank. Table 4.1 shows the changes in resources and risk between the application and before the drilling.

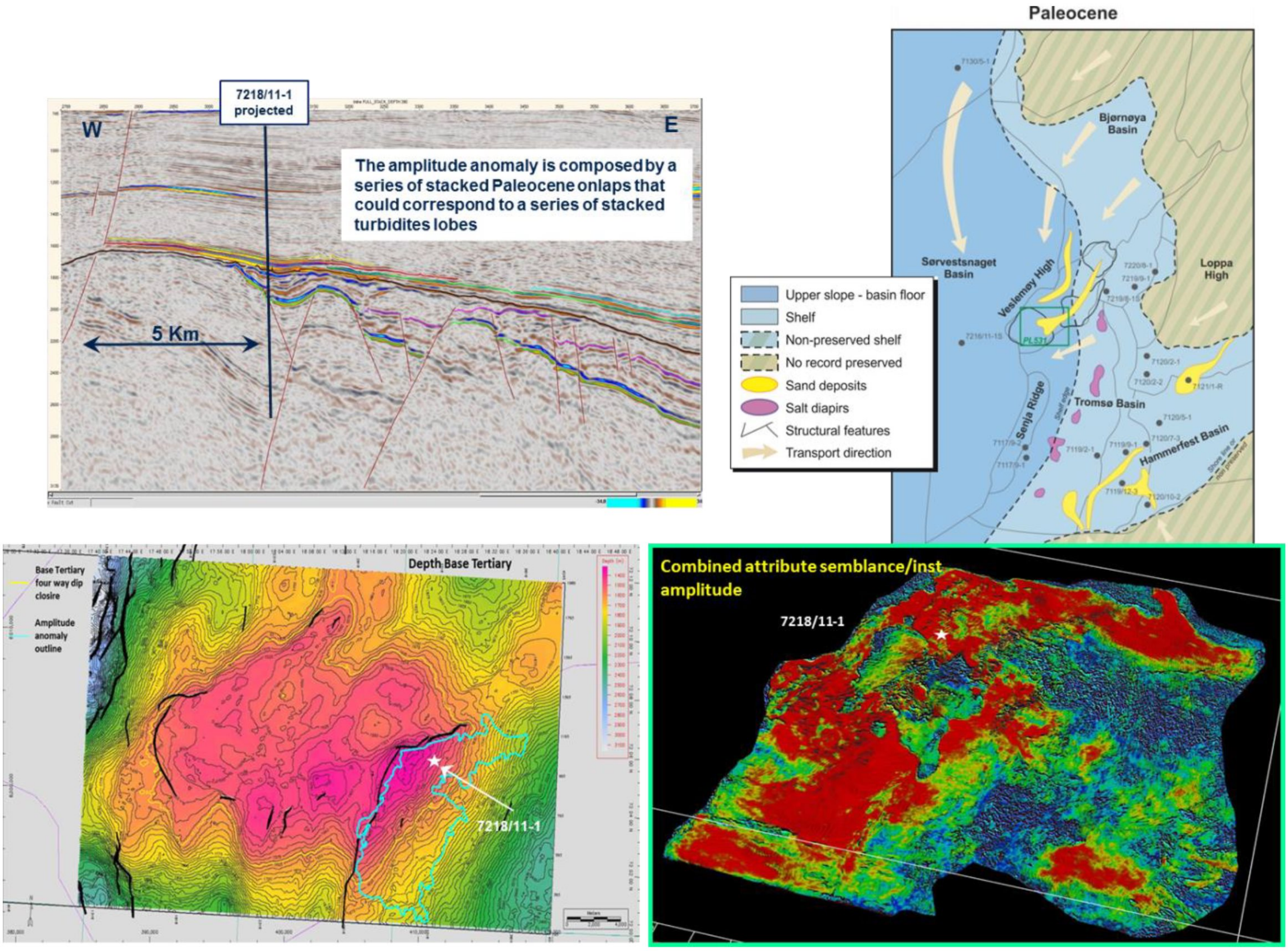


Figure 4.3 Summary of the Paleocene prospect at Darwin

2. Cretaceous beds trapped in halfgrabens underneath the BTU. (see figure 4.4). The trap is partly structural (against normal faults) and partly stratigraphic (truncation against the BTU). The beds were considered to be probably turbidite sandstones sourced by the Loppa High and to be equivalent to the Kolmule and/or Kveite formations in the area of the Hammerfest Basin; their age was thought to be mid to upper Cretaceous. Table 4.1 show the changes in resources and risk between the application and before the drilling.

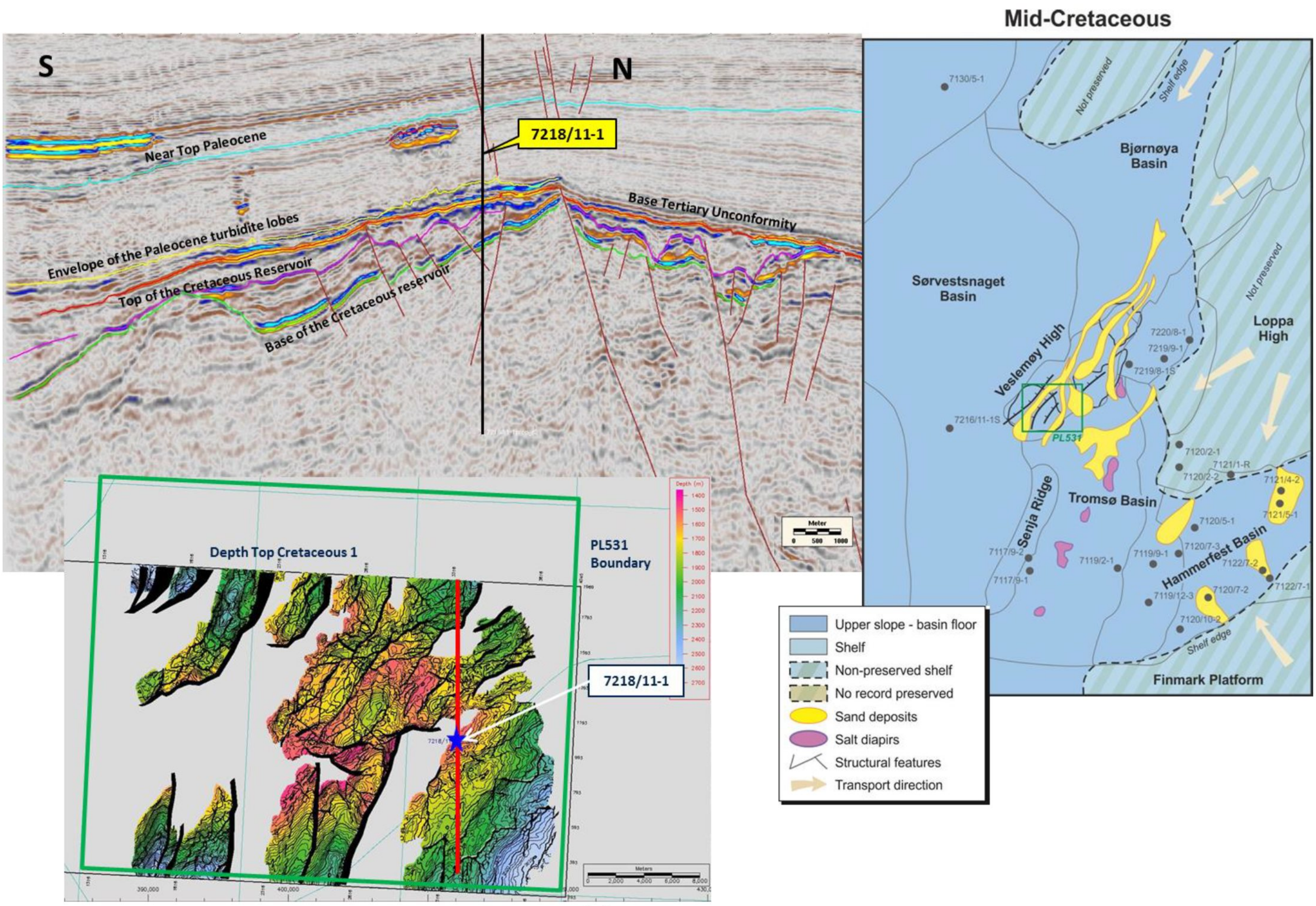


Figure 4.4 Summary of the Cretaceous prospect at Darwin

	Paleocene		Cretaceous	
	Aplication	**Pre-Drill 7218/11-1**	**Aplication**	**Pre-Drill 7218/11-1**
P10 reserves (MMBOE)	391	376.8	384	668.11
Pmean reserves (MMBOE)	164	150	159	253
P90 resreves (MMBOE)	22	20.17	21	27.55
Pg (%)	14	14	8	14.2

Table 4.1 Comparison between resreves estimation from application and pre-drill 7218/11-1

Darwin results, well 7218/11-1

Well 7218/11-1 was drilled by the semi-submersible drilling rig Transocean Barents in a water depth of 324.8 m. The pilot well 7218/11-U-1 was spudded on March 3rd 2013 and drilled to TD at 1155 m. The main well 7218/11-1 was spudded on a separate location 11m NW of the pilot well on March 5th 2013 and the 36" and 17½" sections were drilled to 1155 m. When pulling out of the 17½" section the hole packed off at 1145mMD. Attempts to pull free did not succeed and the string was cut with explosives on wireline on March 13th 2013. The technical sidetrack 7218/11-1 T2 was kicked off from the main borehole at 605m (March 17th) and drilled the 8½" section down to TD at 2542mMD on 2nd April 2013.

Well 7218/11-1 failed to find reservoir sandstones, in either target zones. It did record small gas readings in the Paleocene target zone. The presence of C2-C5 indicates wet, thermogenic gas. No indications of oil have been encountered. The well was permanently plugged and abandoned and classified as a dry well. P&A operations were finished on April 10th, 2013 and Transocean Barents went off hire on April 16th, 2013.

1. <u>Tertiary section</u>

Figure 4.5 shows the CPI for Darwin well. The Upper part of the Tertiary section (approximately 600m and most likely Eocene in age) is characterised by an abrupt drop in the GR, density, sonic velocity and also by high porosities, a log response that could be interpreted as sandstones. However, the cuttings showed a shaly lithology (there were no returns until 1136.5 m MD but seabed samples that most likely correspond to the dumped cuttings were taken after the drilling). This section is interpreted to be Oozes.

The Ooze lithology was predicted before the drilling due to the presence of an anomalous low velocity layer (relatively concordant with the stratigraphy) in the PreSDM velocity cube. Note in figure 4.5 the inversion of the velocity and the low velocities compared to the Barents Sea Eocene deposits at Darwin location.

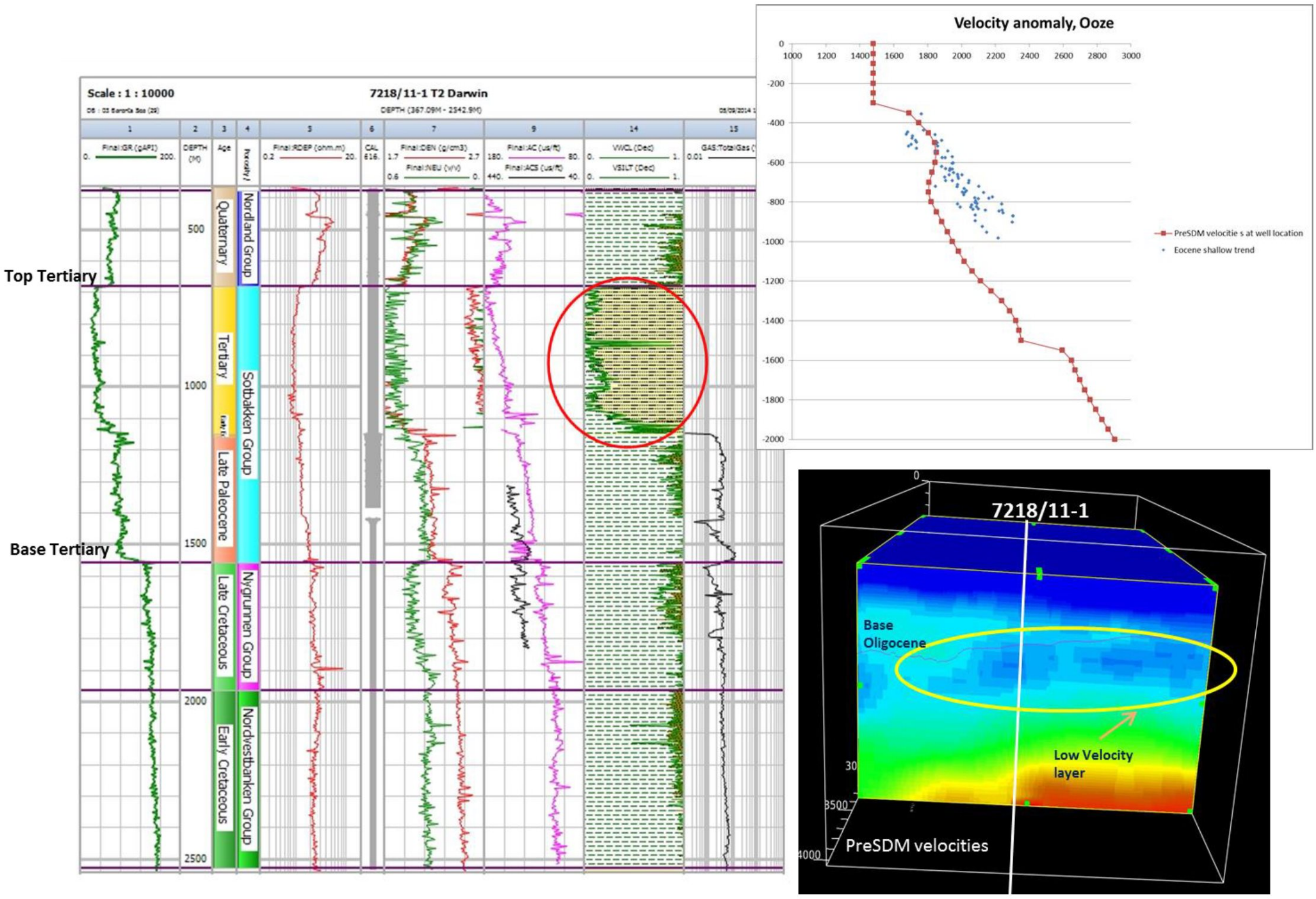
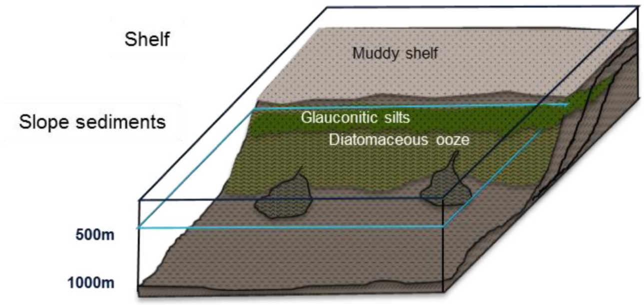
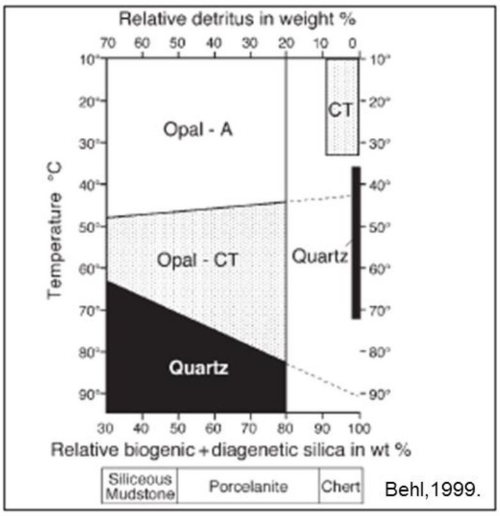


Figure 4.5 CPI Darwin well and low velocity layer (Ooze)

The Ooze are biosiliceous sediments (diatoms, silicoflagelates, radiolarians, etc.) deposited under acid conditions in a slope to upper slope environment with upwelling currents. They are characterised by high productivity and are deposited by suspension, traction and gravity flows. To be present they need clean waters with no siliciclastic input. Once the Ooze is buried, the amorphous silica precipitates and the ooze recrystallize from Opal A to Opal CT and then to Quartz. The depth at which these transformation takes place depends on temperature and purity of the sediments in such a way that, the less pure the sediments are, the deeper they recristillize into the Opal CT and the quicker they transform into the Quartz (see figure 4.6). The Ooze, Opal CT and Quartz are characterised by high porosities but very low permeability. In well 7218/11-1 there were 10 unsuccessful attempts to acquire pressure samples with the MDT tool in the 12 ¼“ section (Quartz Paloecene in age) proving that permeability was non-existent. Same was confirmed by the results of CMR measurement which showed no free fluid.





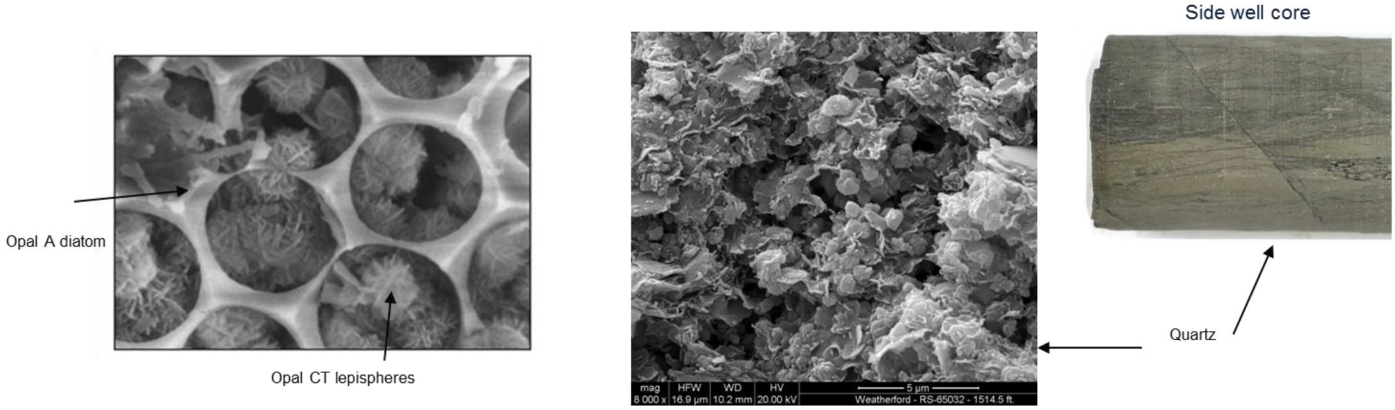


Figure 4.6 Biosiliceous sediments characteristics

Based on the Density-Neutron crossplot and in the 7117/9-1 log response (which also penetrated siliceous deposits), the operator estimated the different intervals of the Opal A, Opal CT and Quartz (see figure 4.7). The data was calibrated with the XRD data from the side well cores (12 ¼" section).

Figure 4.8 shows the lower most part of Paloecene section in well 7218/11-1. Along this section the GR is stable, there is a slight increase in the gas readings (note the scale), and a cross over between the neutron and density log curves. In addition there is an increase of Vs velocity while the VP velocity drops. In the Cretaceous section there is a shale type log response.

Based on the crossplot between P-Impedance and Vp/Vs ratio (figure 4.8) there is a clear differentiation between three intervals: the Cretaceous sediments (high P-Impedance ad Vp/Vs ratio), the Quartz and the anomalous Quartz where there is a big drop in the P-Impedance and Vp/Vs ratio. Our interpretation is that, in such porous sediments just a small saturation of gas produces a drop in the Vp/Vs ratio and that is what is causing the amplitude anomaly that we observed in Darwin.

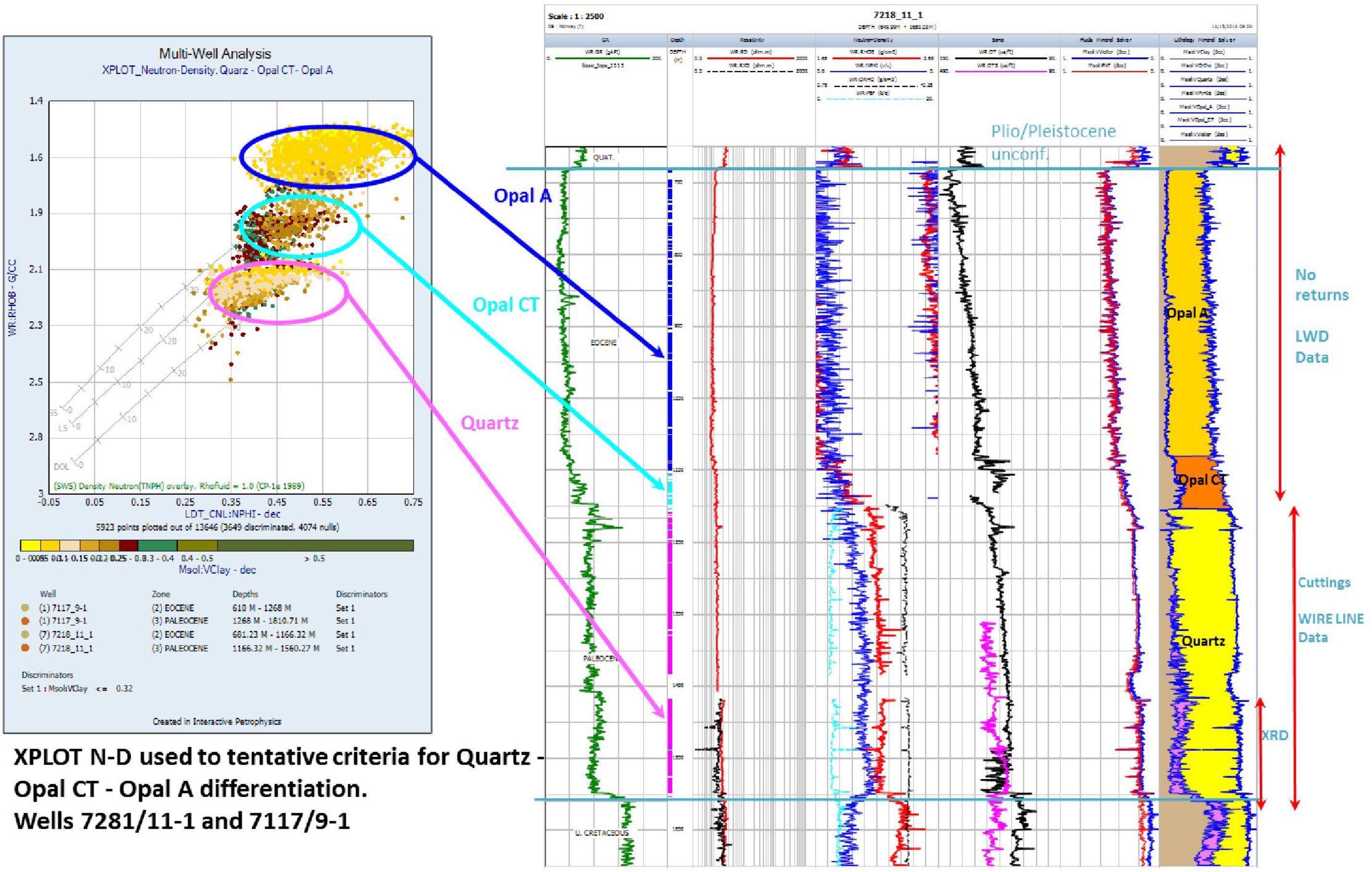


Figure 4.7 Opal A, Opal-CT and Quartz intervals in 7218/11-1

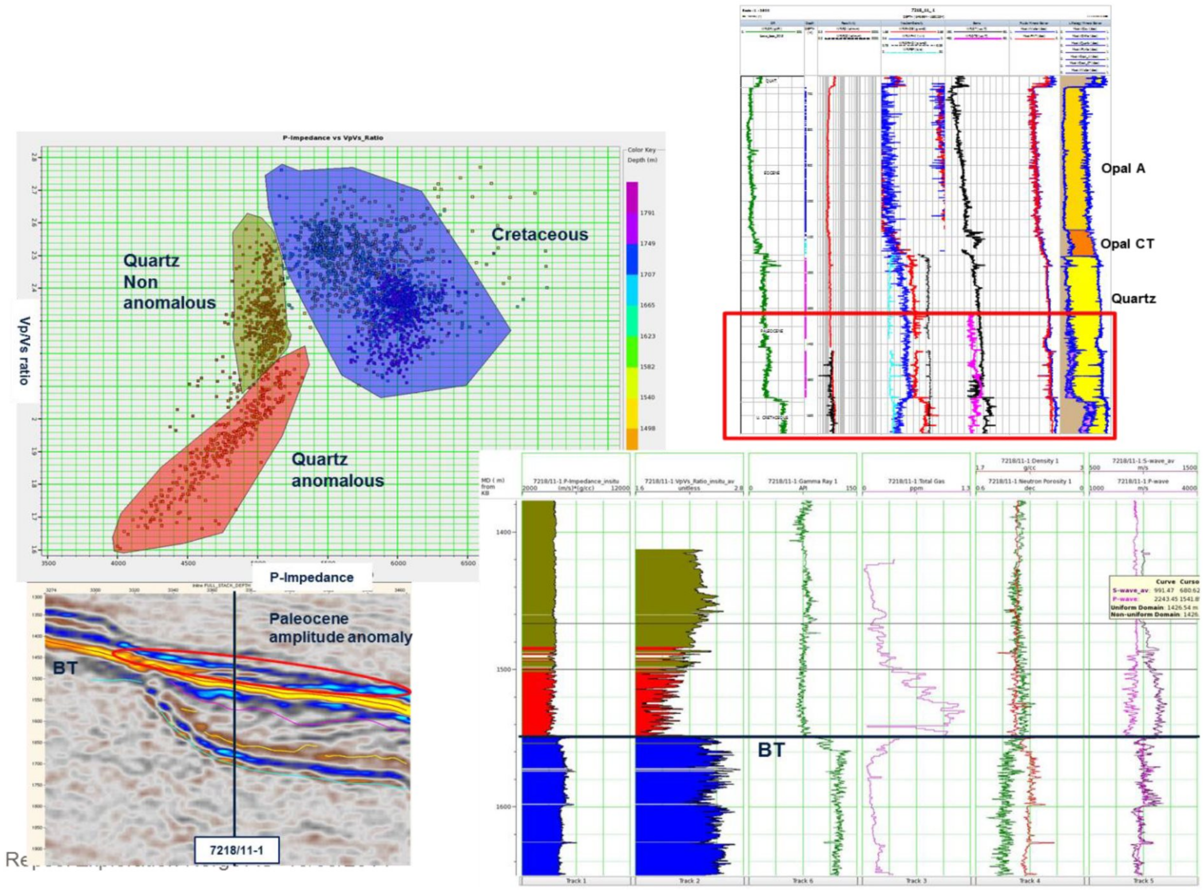


Figure 4.8 Rock physics over Darwin

Cretaceous section

Prior to the drilling of 7218/11-1, as the tie with nearby wells was very bad, there were several uncertainties about the pre-Tertiary sediments in Darwin prospect. There were even some theories indicating that the faulted blocks beneath the Base Tertiary were Jurassic in age. The youngest Cretaceous sediments penetrated are Late Turonian in age. The well TD is in the Late Albian. Based in the fossils records all the Cretaceous section is interpreted to be deposited in an Outer Shelf/Upper slope environment (see figure 4.9).

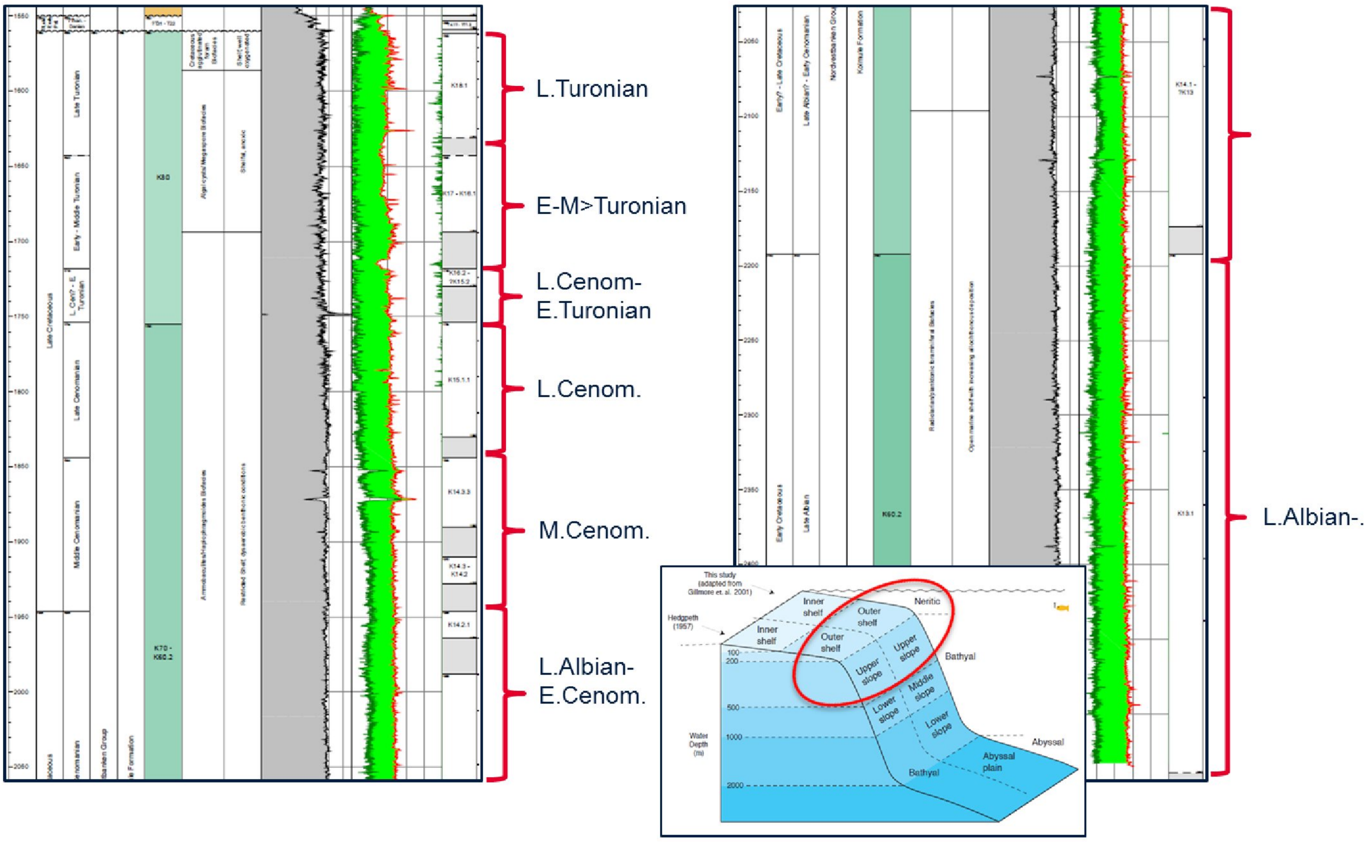


Figure 4.9 Cretaceous Stratigraphy 7218/11-1

In the Upper Cretaceous a relatively high-TOC Zone (2.02 – 3.44; av. 2.70 %) can be recognised by a ca. 150 m thick interval in the Turonian Kolmule Formation based on rock eval analysis from predominantly cuttings samples. As also HI values are relatively elevated (see figure 4.10), this interval represents a new potential source rock but immature at the well location according to the vitrinate reflectance (see figure 4.11). This sequence presents mixed Type II/III kerogen (oil-gas prone) where the Type II (marine organic matter) represents the main contribution (70-80%) (See figure 4.12).

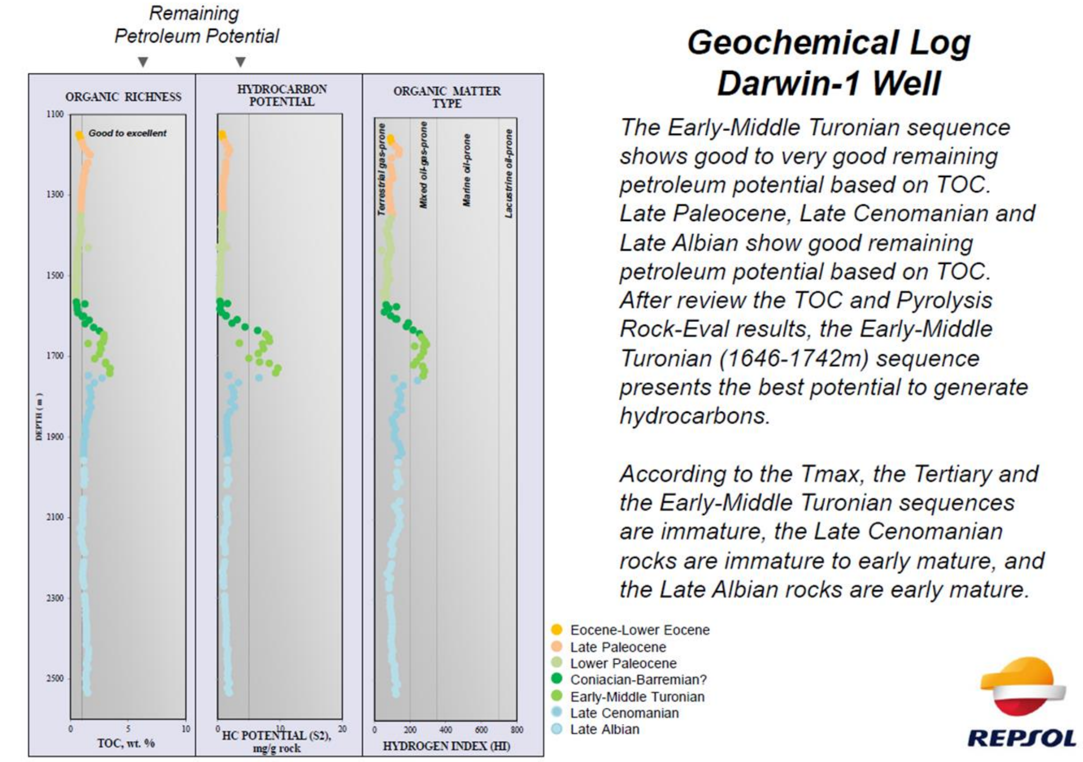


Figure 4.10 Source rock potential 7218/11-1

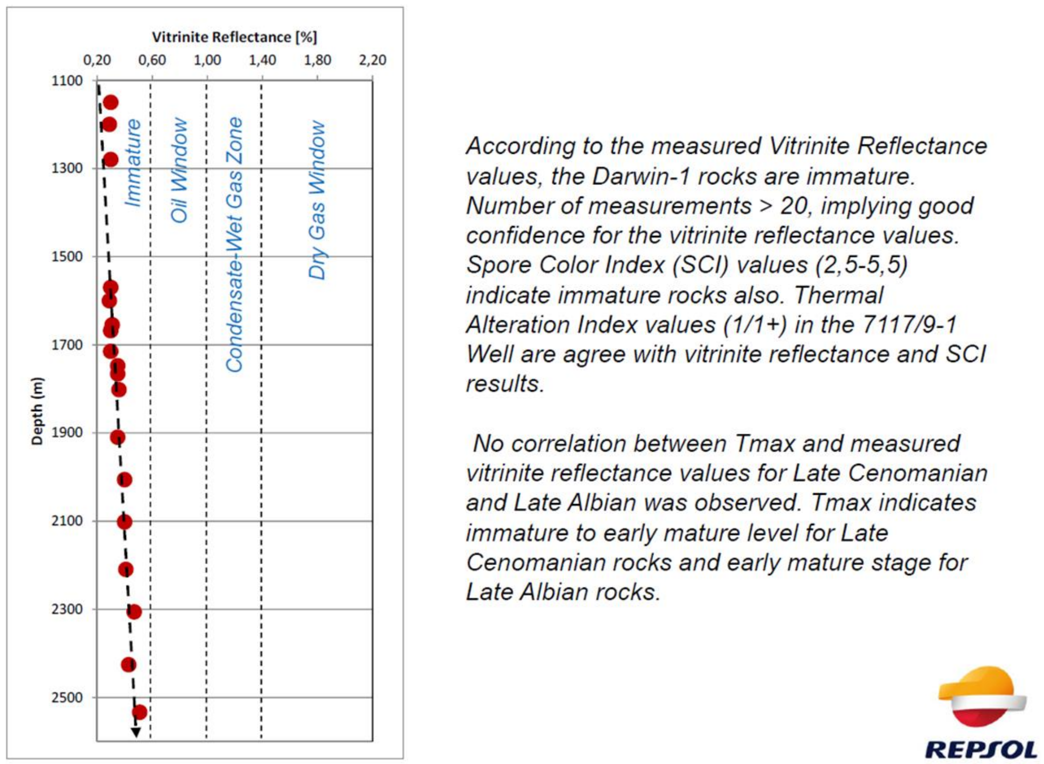


Figure 4.11 Maturity 7218/11-1

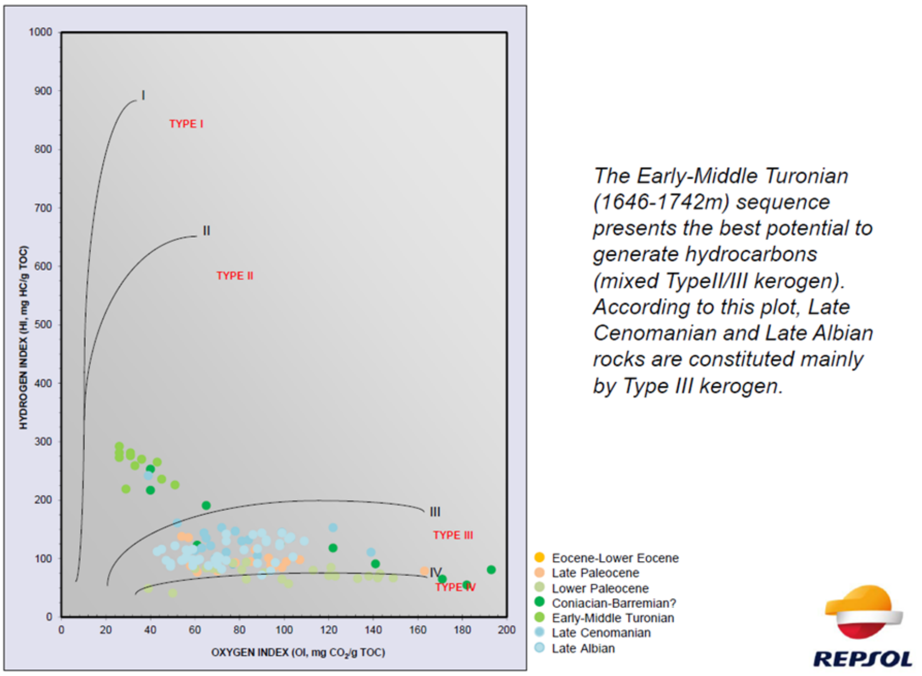


Figure 4.12 Source rock types 7218/11-1

Geochemical analysis of gas from isotubes and headspace gas from cuttings have been carried out. The results indicate the following:

- Gas fractionation (carbon isotope values of methane and ethane) is observed in the cutting gas samples (headspace gas).
- Isotube Darwin-1 gases are of thermogenic origin of an apparent Single Gas Family. The carbon isotopic composition indicates "marine sourced" gases (see figure 4.13). The headgas and the isotubes both show as well that no biodegradation has occurred.
- It appears that the Rc~1.1% better reflects the maximun thermal maturity of the source rock that has generated in the isotube gases. Isotube gases are likely to be condensate associated gas, or gases which result from the mixing of deep dry gases with associated gases. The 13C isotopes of C1, C2 and C3 of headspace gases and the isotubes show reversal with depth that suggests input from different sources and maturity.

Based on the geochemistry interpretation, the compositional analysis of the gas implies that an over mature marine source rock e.g. Hekkingen (Upper Jurassic) or Knurr (Lower Cretaceous) has been generating hydrocarbons in this area.

5 Technical evaluations

For this evaluation, the operator ran a scenario of oil with a 20% gas cap. This scenario assumed the production of oil and the associated gas through a FPSO system, commercialisation of the oil and re-injection of the gas. For the different volumetric estimations, different production profiles were generated with the same MBAL model.

Fluid Properties

To build the production profiles Material balance tool (MBAL) from Petroleum Experts software suite was used. The reservoir was considered as a single layer tank with the OOIP input from the reserves estimation analysis. From the analogous fields and the geological description of the objective from G&G, moderate properties for the sandstones were assumed.

The fluid considered is black oil with fair viscosity and no CO_2 content. The following table shows the PVT characteristics input in the model matched for a bubble point of 2200 psi at 129ºF.

Reservoir Fluid	oil	Oil FVF	1,2 rb/stb
Separator	Single-Stage	Mole percent H2S	0 (%)
Solution GOR	370 (scf/STB	Mole percent C02	0 (%)
Oil gravity	35 (API)	Mole percent N2	0 (%)
Gas Gravity	0,67 (sp Gravitiy)	Pb, Rs, Bo correlation	Glas
Water salinity	70000 (ppm)	Oil viscosity correlation :	Beal et al

Table 5.1. Fluid Characteristics

PVT matched data for Bubble point 2200 psi at 129ºF:

Pressure	Gas Oil Ratio	Oil FVF	Oil Viscosity	Z Factor	Gas FVF	Gas Viscosity	Oil Density	Gas Density	Water FVF	Water Viscosity	Water Density
(psig)	(scf/STB)	(RB/STB)	(cp)		(ft3/scf)	(cp)	(lb/ft3)	(lb/ft3)	(RB/STB)	(cp)	(lb/ft3)
1000	147,726	1,08073	2,14464	0,8735	0,014342	0,0135232	50,34	3,56927	1,00963	0,647138	64,8168
1133,33	170,28	1,09165	2,03356	0,85971	0,012476	0,0138587	50,0249	4,10304	1,00924	0,647138	64,8418
1266,67	193,322	1,10314	1,9296	0,84703	0,011013	0,0142255	49,6942	4,64811	1,00885	0,647138	64,8668
1400	216,876	1,11521	1,83206	0,83562	0,009841	0,0146233	49,3489	5,20189	1,00846	0,647138	64,8919
1533,33	240,964	1,12787	1,74039	0,8256	0,0088852	0,0150514	48,99	5,76126	1,00807	0,647138	64,9169
1666,67	265,603	1,14111	1,65409	0,81708	0,0080961	0,0155082	48,6184	6,32272	1,00768	0,647138	64,942
1800	290,812	1,15494	1,57275	0,81014	0,0074375	0,0159914	48,2353	6,88256	1,00729	0,647138	64,9671
1933,33	316,605	1,16937	1,49602	0,80482	0,0068829	0,0164984	47,8416	7,4371	1,0069	0,647138	64,9922
2066,67	342,996	1,18438	1,42359	0,80111	0,0064123	0,0170259	47,4382	7,98294	1,00652	0,647138	65,0174
2200	370	1,2	1,35518	0,79896	0,0060102	0,0175704	47,0262	8,51709	1,00613	0,647138	65,0426
2333,33	370	1,19844	1,36639	0,79832	0,0056643	0,0181287	47,0873	9,03709	1,00574	0,647138	65,0677
2466,67	370	1,19705	1,3776	0,79909	0,0053651	0,0186972	47,1419	9,54107	1,00535	0,647138	65,0929
2600	370	1,19581	1,38881	0,80117	0,0051048	0,0192729	47,191	10,0277	1,00496	0,647138	65,1182
2733,33	370	1,19468	1,40002	0,80444	0,0048769	0,0198529	47,2354	10,4962	1,00457	0,647138	65,1434
2866,67	370	1,19367	1,41123	0,8088	0,0046764	0,0204348	47,2757	10,9462	1,00418	0,647138	65,1686
3000	370	1,19274	1,42244	0,81414	0,0044991	0,0210164	47,3124	11,3775	1,00379	0,647138	65,1939

Table 5.2. PVT

To define the tank for the Material Balance Tool (MBAL) the following parameters were used as input. The size of the gas cap was calculated to achieve the RA gas production quantities.

Reservoir Temperature	129 (deg F)
Reservoir Pressure	2200 (psia)
Reservoir Porosity	0,21 (fraction)
Connate Water Saturation	0,32 (fraction)
Water Compressibility	Use Corr (1/psi)
Initial gas cap	0.258

Table 5.3. Peter Rose parameters

No active aquifer drive was considered so a water injection project was envisaged to develop the field and enhance oil recovery. Seawater is considered to supply the required water.

Relative permeability curves were estimated for an average sandstone reservoir.

	Residual Saturation (fraction)	End Point (fraction)	Corey Exponent
Krw:	0,32	0,6	3
Kro	0,25	1	2
Krg	0,1	0,5	3

Table 5.1. Relative permeability parameters

For the initial reservoir pressure, we have considered standard gradients and followed them to the prognosis depth for the reservoir 1460 m.

Wells productivity

The individual wells productivities were estimated using the specified characteristics given by G&G and the analogous data from Draugen Field .

Torsk reservoir (Paleocene)

A well model was constructed with a slanted geometry and the following characteristics resulted in a Productivity Index of 15 stb/d/psi with skin value of two.

Reservoir permeability	300 mD
Reservoir thickness	30 m
Drainage area	1200 acres
Skin	2
Total MD	1700 m
Total TVD	1500 m
Max deviation angle	66 º

Table 2.5. Productivity Index parameters Torsk

It was considered that all the wells producing from this reservoir would be completed with gas lift systems at a maximum depth of 1300 m.

Cretaceous reservoir

A well model was constructed with a slanted geometry and the following characteristics that resulted in a productivity Index of 13 stb/d/psi with skin value of two.

Reservoir permeability	200 mD
Reservoir thickness	40 m
Drainage area	1200 acres
Skin	2
Total MD	1500 m
Total TVD	14600 m
Max deviation angle	32 º

Table 5.6. Productivity Index parameters Kolmulle

It was considered that all the wells producing from this reservoir would be completed with gas lift systems at a maximum depth of 1300 m

Paleocene and Cretaceous commingled production prospects: Production profiles

P MEAN TRUNCATED: 453 MBO

With the production profiles a MEFS of 148 MBO was estimated. Resources were truncated with the MEFS resulting in a new distribution with a P_{mean} of 453 MBO (truncated).

The general characteristics of the profile are:

- Production profile duration 20 years with 3 years plateau duration
- A recovery factor of 31%
- Plateau production rate 115000 bopd with maximum water rate at the end of the production profile of 80000 bwpd
- Maximum water injection rate 165000 bwpd and GLR for gas lift 300 scf/stb
- The produced gas is used for gas lift and the remaining injected in a disposal well.

In table 5.7 are shown the details of the different production profiles.

year	Tank Pressure Torsk (psig)	Tank Pressure Kolmule (psig)	Avg.Oil Rate added (STB/day)	Avg.Gas Rate (MMscf/day)	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Avg.Water Inj Rate (STB/day)	Avg.Gas Lift Rate (MMscf/day)	Cum Oil Produced (MMSTB)	Cum Gas Produced (MMscf)	Cum Wat. Produced (MMSTB)	Cum Wat. Injected (MMSTB)	Number of	Number of
1	2200	2200	95718	58,3	0	95719	59719	28,7	35,0	21348	0,0	12,7	16	13
2	2141	2117	115000	93,7	16	115016	104039	34,5	77,0	55543	0,0	34,4	29	20
3	2067	2035	115000	121,5	146	115146	133594	34,5	119,0	99891	0,1	65,1	35	23
4	1978	1960	114477	148,5	689	115166	149421	34,5	160,8	154097	0,3	99,3	35	23
5	1871	1875	109512	164,7	2210	111722	163159	33,5	200,8	214373	1,1	137,0	35	23
6	1768	1781	100148	164,6	5306	105454	165000	31,6	237,4	274452	3,1	175,4	35	23
7	1684	1681	78368	125,8	9004	87372	165000	26,2	266,0	320362	6,3	213,7	35	23
8	1653	1614	58733	72,8	12597	71330	165000	21,4	287,4	346940	10,9	252,0	35	23
9	1673	1606	48527	37,6	17022	65550	165000	19,7	305,2	360715	17,2	290,4	35	23
10	1725	1640	45452	20,9	23547	68999	165000	20,7	321,8	368347	25,8	328,8	35	23
11	1792	1697	44853	14,7	31910	76762	165000	23,0	338,2	373697	37,4	367,1	35	23
12	1865	1763	44155	13,3	41181	85336	162672	25,6	354,3	378542	52,4	405,4	35	23
13	1932	1831	42921	13,3	50346	93267	154486	28,0	370,0	383398	70,9	442,2	35	23
14	1986	1892	40668	13,0	58021	98689	144943	29,6	384,8	388134	92,0	476,6	35	23
15	2027	1940	37851	12,4	64014	101865	137407	30,6	398,7	392654	115,4	509,1	35	23
16	2059	1978	35036	11,7	68825	103860	131501	31,2	411,4	396919	140,5	540,0	35	23
17	2083	2008	32306	10,9	72573	104879	126867	31,5	423,3	400921	167,1	569,9	35	23
18	2102	2032	29734	10,2	75406	105141	123166	31,5	434,1	404639	194,6	598,7	35	23
19	2117	2052	27391	9,5	77586	104977	120147	31,5	444,1	408096	222,9	626,8	35	23
20	2130	2068	25266	8,8	79229	104494	117606	31,3	**453,3**	411311	251,9	654,2	35	23

Table 5.7. Production profile table for Pmean truncated case 453 Mbo

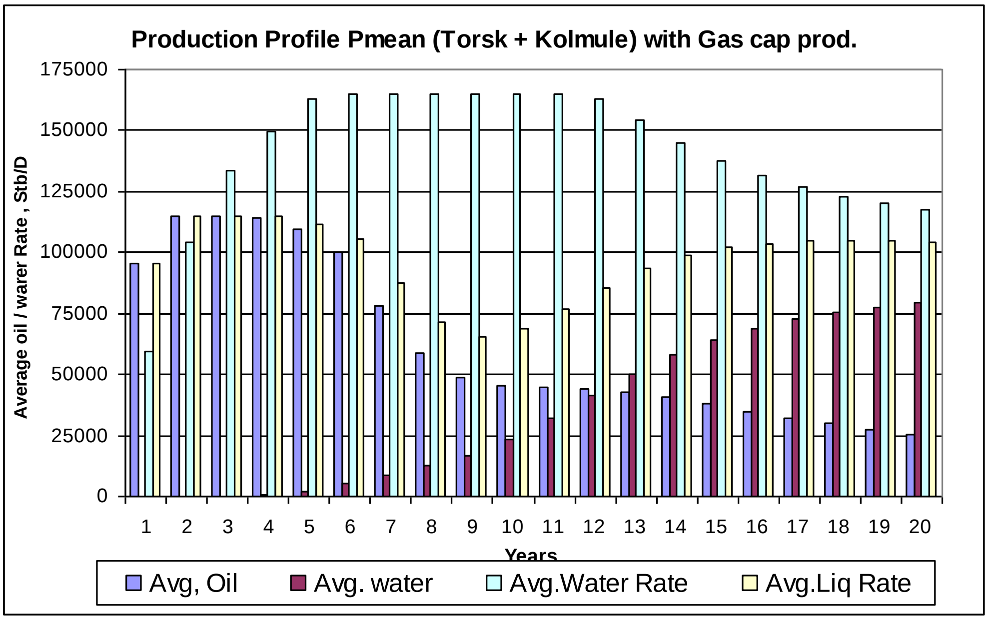


Figure 5.1. Production profile case Pmean truncated case

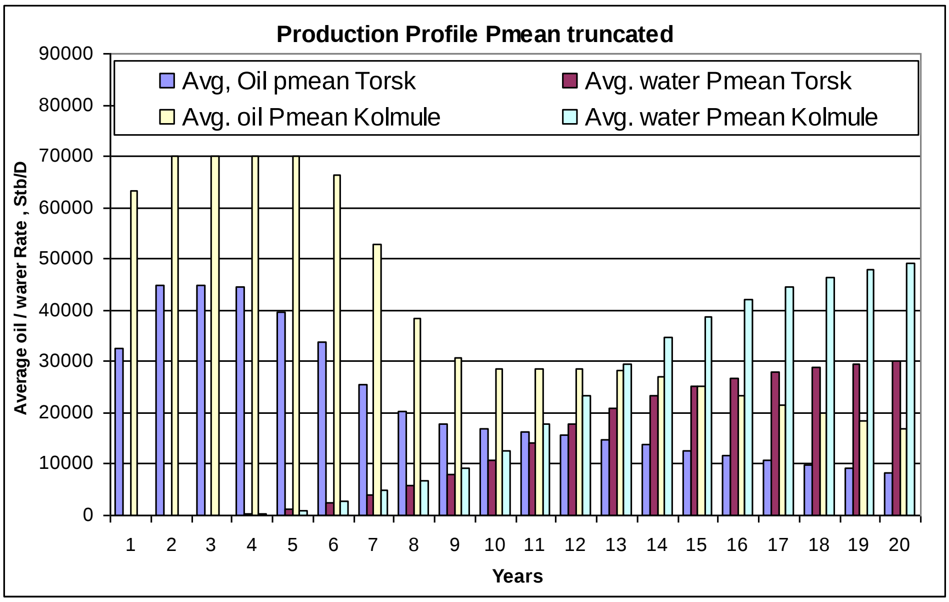


Figure 5.2. Production profile case Pmean truncated case

Development Concept

One development concept was used for all the cases, P_{mean} case is shown as an example:

FPSO would be used for production and processing and the development would be subsea:

Oil will be produced via gas lift and then exported via tanker. Sea water and produced water will be re-injected to reservoir pressure maintenance. The remaining gas will be re-injected into the reservoir.

As said before, the development for the 80% Oil and 20% Gas is similar.

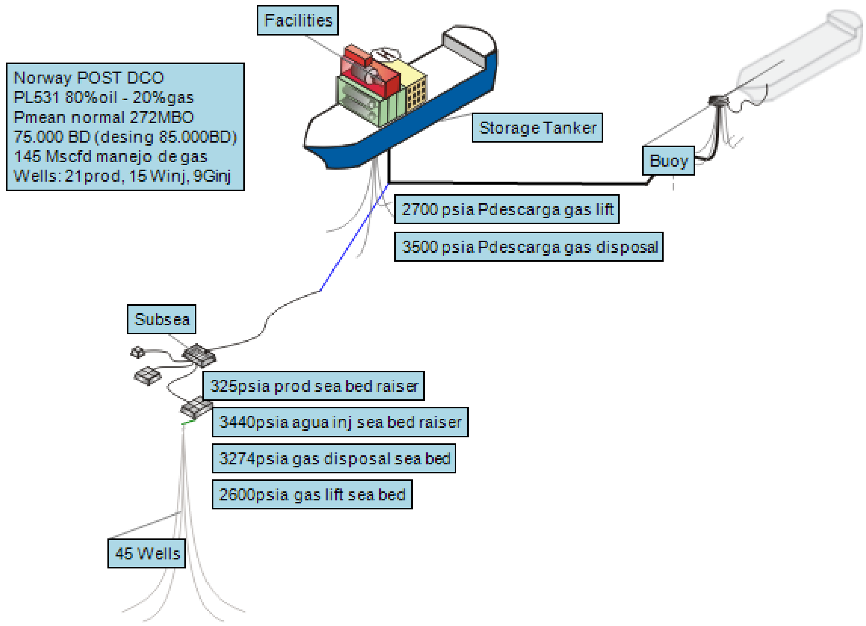


Figure 5.3. Field Development for Torsk and Kolmulle

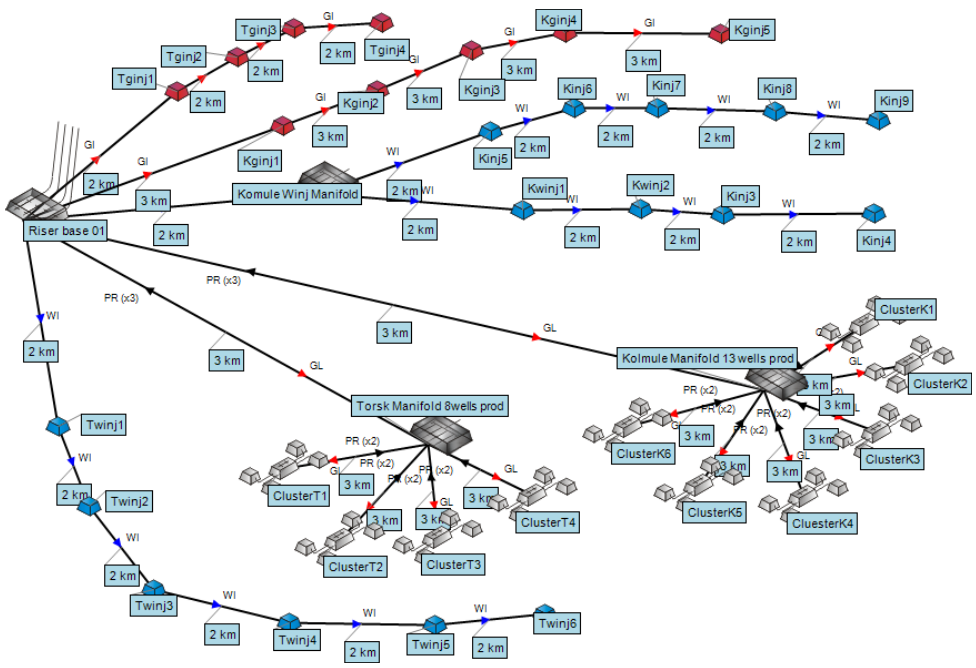


Figure 5.4. Subsea Field Development for Torsk and Kolmulle

Schedule & CAPE/OPEX

Figure 5.5 shows the proposed schedule for the development project of the gas case.

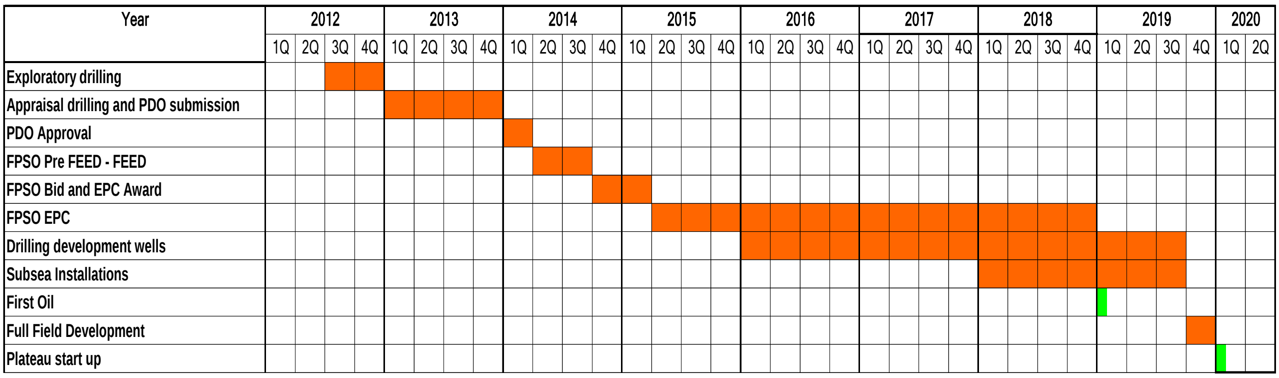


Figure 5.5. Development Schedule

	Cases with gas cap production - Post DCO			Cases with gas cap production - Post DCO		
	MEFS 96 MBO		Truncated T + K	MEFS 143 MBO		Truncated T + K
	Torsk + Komule			Torsk + Komule		
	P90 38 MBO	Pmean 275 MBO	Mean 383 MBO	P90 37 MBO	Pmean 272 MBO	Mean 453 MBO
Reserves (M Boe)	**38**	**275**	**383**	**37**	**272**	**453**
Gas Reserves (Sales) (Bscf)	0	0	0	0	0	0
Liquids Reserves (Sales) (MBbls)	37,8	274,8	383,0	36,7	271,6	453,3
Production						
Concept Development	**Subsea + Tie back to FPSO**	**Subsea + Tie back to FPSO**	**Subsea + Tie back to FPSO**	**Subsea + Tie back to FPSO**	**Subsea + Tie back to FPSO**	**Subsea + Tie back to FPSO**
Gas Rate (Peak Production) (Mscfd)	6 + 4,8	25 + 20,4	34,7 + 30	16,7 + 4,8	106,7 + 25,2	165 - 35
Oil Rate (Production Plateau) (BPD)	16.000	70.000	100.000	17.000	75.000	115.000
Oil Facilties design (BPD)	17.600	77.000	110.000	18.700	83.000	125.000
Liquid Rate (Maximum) (BPD)	17.500	74.500	105.500	17.100	75.500	115.000
First Oil (Date)	2021	2021	2021	2021	2021	2021
Plateau duration (yr)	2	4	4	2	3	3
Field Life (yr)	10	20	20	10	20	20
EXPLORATION PHASE						
Exploration expenditure (M$)	217	360	612	217	360	612
Studies (M$)						
CAPEX (M$)						
Development Drilling & Completion Wells	490	1832	2625	542	2690	4318
Subsea	488	1658	1850	425	1440	2304
FPSO Topsides + Tanker	526	1757	1944	544	1810	2090
Owner's Cost	61	341	360	48	163	340
Studies	5	5	5	5	5	5
TOTAL CAPEX	**1570**	**5593**	**6784**	**1564**	**6107**	**9057**
OPEX (M$)						
Operating personnel costs	300	1460	1640	300	1460	2000
Inspection, maintenance and Insurance costs & Logistics and consumables costs	552	3120	3500	570	3320	4560
Field project costs	322	620	760	322	620	848
TOTAL OPEX	**1173**	**5200**	**5900**	**1191**	**5400**	**7408**
Abandonment Costs (M$)	**336**	**1202**	**1692**	**369**	**1647**	**2504**
Well Count	Appraisal no converted	Appraisal no converted	Appraisal no converted	Appraisal no converted	Appraisal no converted	Appraisal no converted
Exploration	1	1	1	1	1	1
Appraissal	2	4	8	2	4	8
Production wells	4	17	25	4	21	35
Water injection wells	3	11	14	4	15	23
Gas injection wells	1	2	4	1	9	14
UNIT EXPLO CAPEX ($/bbl)	5,75	1,31	1,60	5,92	1,32	1,35
UNIT CAPEX ($/bbl)	41,54	20,35	17,71	42,63	22,49	19,98
UNIT OPEX ($/bbl)	31,03	18,92	15,40	32,46	19,88	16,34
ABANDONMENT COST ($/bbl)	8,89	4,38	4,42	10,04	6,06	5,52
TOTAL COST ($/bbl)	**87,21**	**44,96**	**39,13**	**91,06**	**49,75**	**43,19**

Table 5.8

6 Conclusions

The lack of reservoirs in 7218/11-1S (Darwin) has a clear negative impact in PL531 and limits the prospectivity of the licence for the Cretaceous and the Palaeocene play. Additionally, well 7218/8-1 (Byrkje, drilled on March 2014 north of PL531) with main objective in Cretaceous sediments, had similar results as Darwin. The well didn't encounter a competent reservoir in the Cretaceous, just only a shallow siltstone layer in the Kviting formation with elevated gas readings in a gross interval of about 35 metres. The well was classified as dry, with traces of gas.

Based on the well results the conclusions about the Cretaceous and Tertiary play are:

- *Tertiary play*: The Tertiary sequence is composed by biogenic siliceous sediments, deposited in an upper slope environment with minor siliciclastic input. Amplitude anomalies most likely are related to diagenetic processes (such as Opal A-Opal CT-Quartz transitions) with some small gas saturations.
- *Cretaceous play*: The Turonian/Albian sediments in PL531 are likely to be far from sand fairways and therefore, there is a limited chance to find Cretaceous reservoirs in the licence.

The remaining prospectivity in the licence might be in the Jurassic play, not tested by the Darwin well. However, there are several uncertainties related to this play:

- Depth: As there is not a clear correlation with nearby wells, there is a big uncertainty of where the Jurassic is. In fact, the licence has currently two possible interpretations (see figure 6.1 and 6.2).

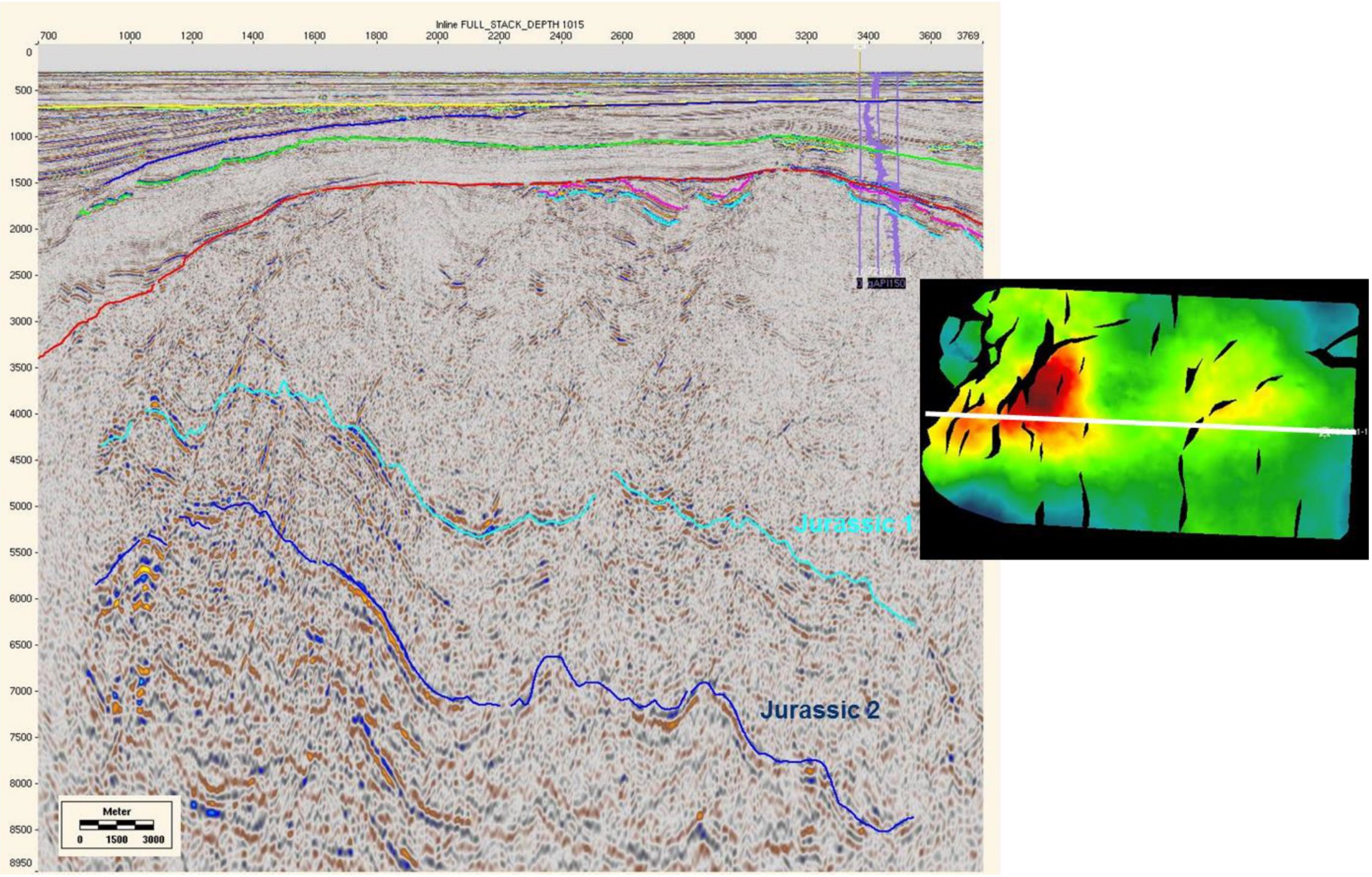


Figure 6.1 Two Top Jurassic (Stø Fm.) Interpretations

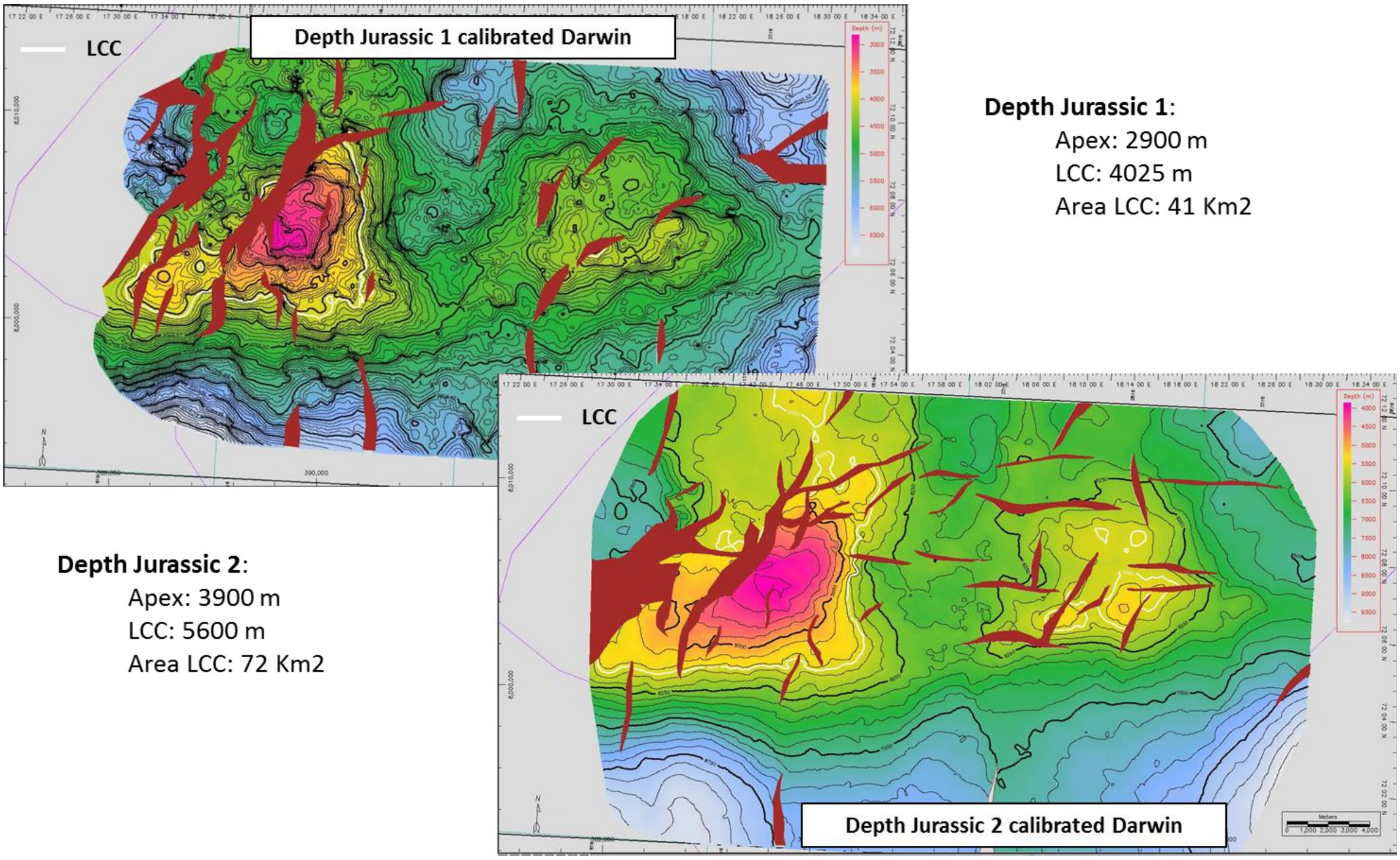


Figure 6.2 Depth maps of the two interpretations of the Top Jurassic

- Reservoir quality: The main reservoir is considered to be the Stø Fm. The current depth of the apex of the prospect is estimated to be between 3000-4000 m. Considering an uplift between 500 m-1000 m, the minimum burial depth would have been of 3500 m – 4500 m. There are factors that may prevent the porosity destruction and therefore preserve the reservoir quality (see figure 6.3):
    - The cementation and therefore, the porosity destruction, can be minimised by the migration of hydrocarbons into the reservoir before the maximum burial depth is reached (early migration). Figure 6.3 shows the effect of the presence of HC in the Halten Bank wells (Norwegian Sea). There is an increase of 1 porosity unit due to the presence of HC.
    - Overpressure: Figure 6.4 show the spatial distribution of the overpressured wells. The overpressured wells are deep wells (for the Stø Fm) located in the western flank of the Loppa High (close to Veslemøy High) and the Hammerfest Basin. Data indicates that the Veslemøy High area is likely to be overpressured. Based on the Halten Bank wells (figure 6.3) the overpressure may increase the porosity up to 3-4 units. Figure 6.3 shows the variation of porosity with depth for Stø Fm. Considering the most optimistic case (maximum burial depth of 3400 m and overpressure) porosity could be as much as 9-10%.

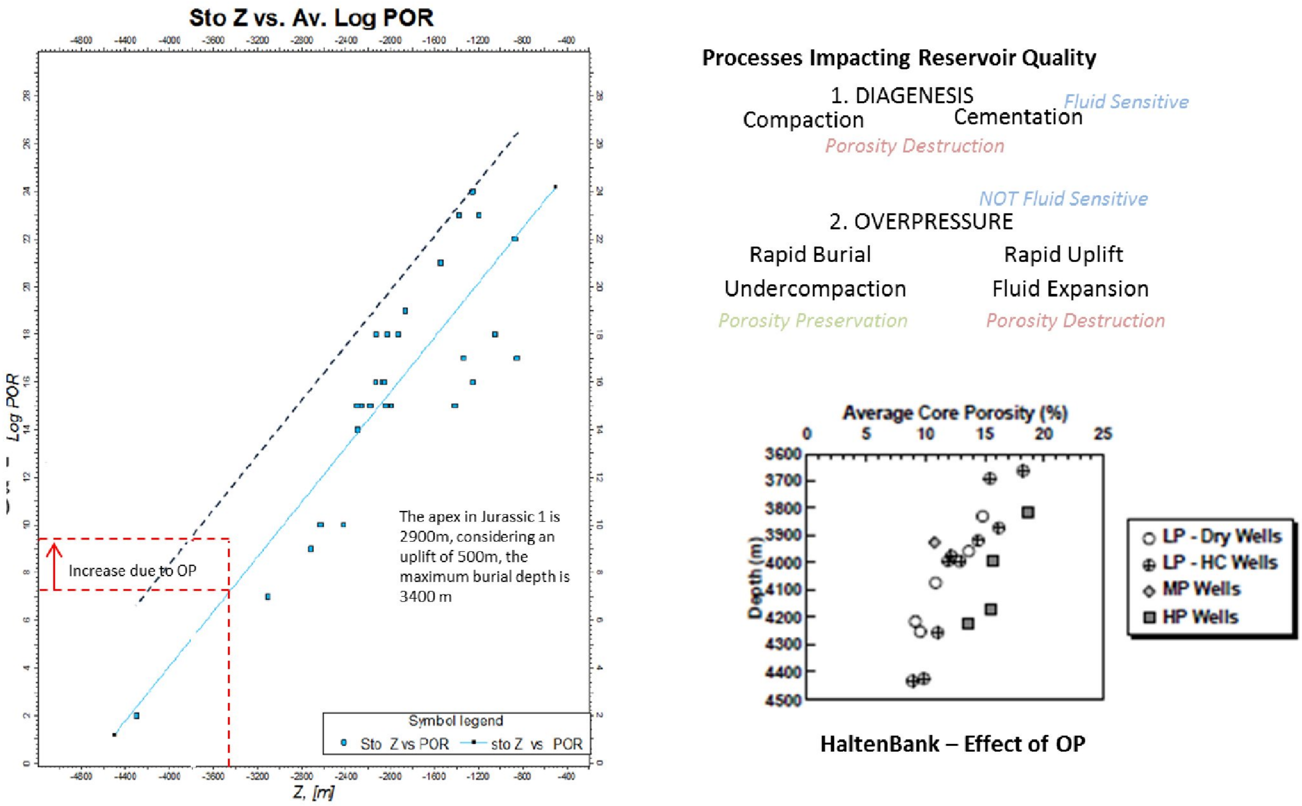


Figure 6.3 Porosity vs Depth for the Stø Fm.

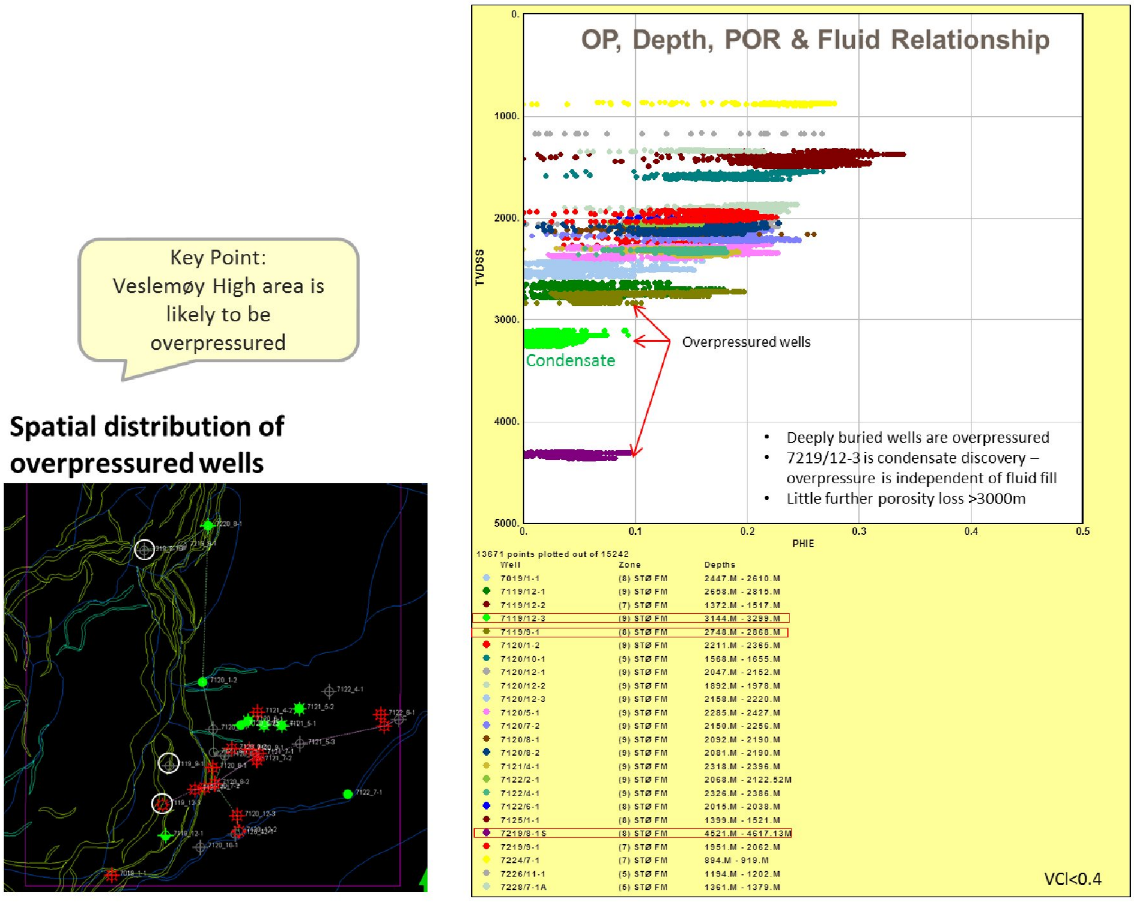


Figure 6.4 Spacial distribution of overpressured wells in Barents Sea

Figure 6.5 shows the resources for the Jurassic prospect and their risk. The Jurassic prospect is a high risk prospect (Pg of 12%) with sub commercial reserves.

Simulation Current	Original In Place		Prospective Undiscovered Recoverable Resources				
			Liquids		Sales Gas		Total Geologic Pre-Drill
	Oil	Raw Gas	Oil	Total Cond	Non-Assoc	Soln	
	MMBO	BCF	MMBO	MMBO	BCF	BCF	BCFE
P99	0,00	83,34	0,00	1,04	50,23	0,00	56,44
P90	0,00	179,69	0,00	2,29	109,20	0,00	122,96
Mode	0,00	262,88	0,00	2,72	162,15	0,00	180,75
P50	0,00	427,47	0,00	4,58	262,95	0,00	290,43
Mean (P99->P01)	0,00	500,27	0,00	6,20	306,67	0,00	343,85
P10	0,00	937,50	0,00	12,47	575,85	0,00	650,65
P01	0,00	1734,75	0,00	24,91	1074,18	0,00	1223,62

Current settings...
Estimating method:
VOLUMETRIC (Area X Net Pay X HC Yield)
Intermediate Simulation: 5000 Iterations
Resources Simulation: 5000 Iterations
Truncations:
Input= 0,00/1,00
Output= 0,00/1,00
Area-Net Pay Correlation = 0%
Raw Gas Surface Loss:
1,13%/2,00%/LOGNORMAL
Percentile Sorting: Only HC Equiv is sorted.
(Warning...resource components are not sorted but are linked to the HC Equiv volume.)

Chance of Success >> Pg-Chance of Geologic Success (>=Ab Min resource) 12,1%

EXPLORATION PROSPECT Chance Success	Ratings (0.00-1.00)
SOURCE COMPONENTS	Confidence of P99 Resources: 56,44 BCF
Quantity/Volume (include Monetizable Product)	0,80
Quality/Richness	0,80
Maturation	1,00
MINIMUM FACTOR	0,80
MING/ MIGRATION/PRESERVATION COMPONEN	Confidence of P99 Resources: 56,44 BCF
Timing of Closure / Trap	0,80
Timing of Expulsion	0,80
Effective Migration Pathway	0,80
Preservation (Spillage or degradation)	0,70
MINIMUM FACTOR	0,70
RESERVOIR COMPONENTS	Confidence of P90 NetPay: 29,12 Metres
Presence	0,80
Quality	0,40
Reservoir Performance	0,50
MINIMUM FACTOR	0,40
TRAP GEOMETRY (CLOSURE) COMPONENTS	Confidence of P90 Area: 6,55 SqKm
Map Reliability & Control	0,60
Presence	0,60
Data Quality	0,60
MINIMUM FACTOR	0,60
SEAL COMPONENTS	Confidence of P99 Resources: 56,44 BCF
Top Seal Effectiveness	0,90
Lateral Seal Effectiveness	0,90
Base Seal Effectiveness	
0	
MINIMUM FACTOR	0,90
EXPLORATION PROSPECT Chance of Success (calculated)	12,1%
EXPLORATION PROSPECT Chance of Success OVERRIDE	
FINAL Chance of Success	12,1%

Figure 6.5 Jurassic prospect estimated reserves and risks

Based on the above exposed, the licence group has agreed to relinquish the PL531 licence due to:

- Limited prospectivity of the Cretaceous & Tertiary play.
- Sub commercial resources estimated for the remaining Jurassic prospect.