RELINQUISHMENT REPORT

PL 601

PL 601 Relinquishment Report

Prepared by Wintershall Norge AS

November 2015

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1 Key License History

Production License 601 was awarded to Wintershall Norge AS (40%, operator). Additional partners at the time of award were: Rocksource ASA (20%), North Energy ASA (20%) and Edison International Norway Branch (20%). The PL 601 License became effective on 13 May 2011, it covers blocks 6609/3, and 6610-1 in the Mid Norwegian Sea with a total area of 814,988 sqkm Fig. 1.1). The PL 601 License Current license partnership is: Wintershall Norge AS (40%, operator), North Energy ASA (20%), Edison Norge AS (20%), PURE E&P Norway AS (10%) and Atlantic Petroleum Norge AS (10).

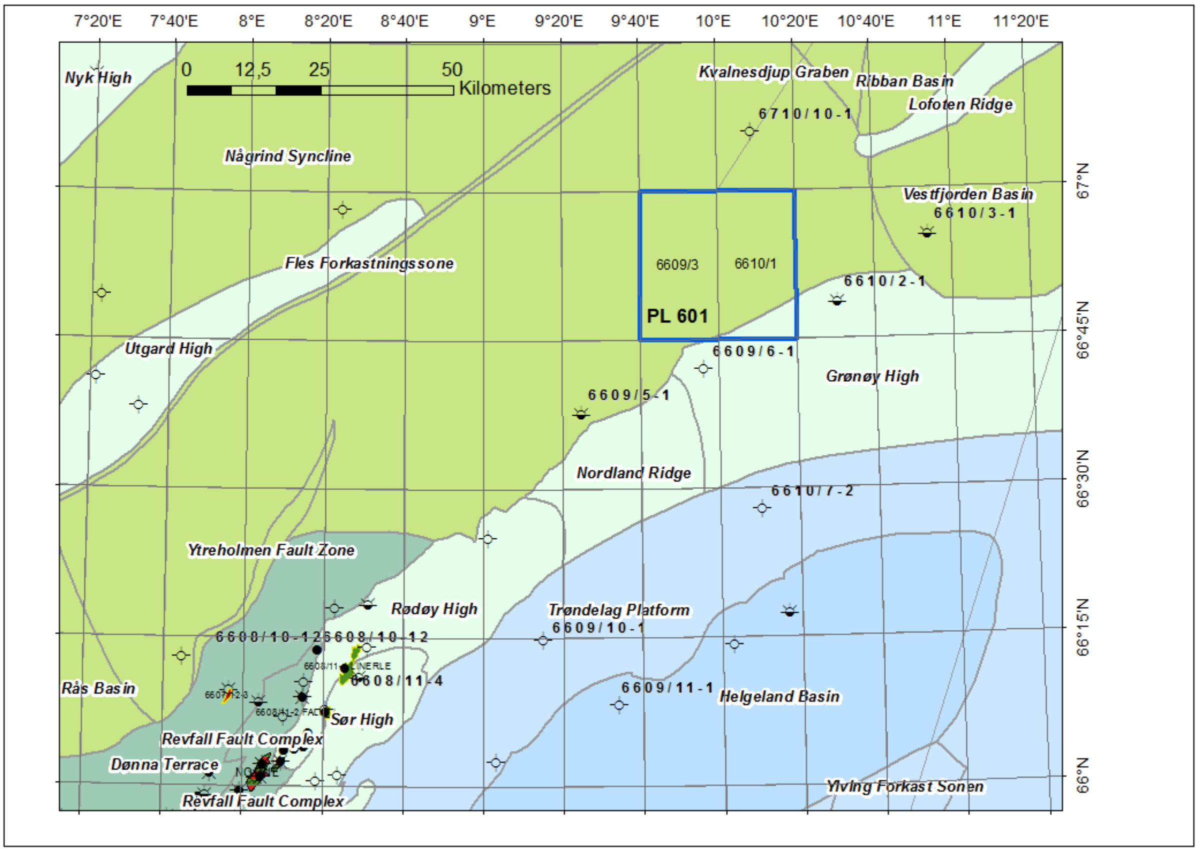


Fig. 1.1 PL 601. Regional Province map

The work commitment of the license included Re-processing of existing 3D seismic in the area of the production license for improved imaging at all prospective levels. Also 250 sqkm of new 3D seismic was to be acquired, in addition to carry out G&G studies, and if deemed useful, acquire CSEM data. The work commitment has been fulfilled.

The partners in PL 601 acquired 554 sqkm of new seismic 3D data (WIN12002), which was merged with existing 3D datasets, covering the license area. The interpretation of the resulting dataset made the partnership realize that there was too much imaging uncertainty to take a drilling decision on any of the identified prospects. The partnership therefore initiated re-processing of a swath of the existing data, located within the license area, in order to assess the potential for data improvement. This was done after MPE had granted the PL 601 license an 18 months extension to the license, with a new DoD date of 13th of November 2015.

The swath re-processing was a success, but did not improve the view of prospectivity in the license. In particular the swath data over the Blekksprut prospect led to an increase of the top seal risk. In addition the resulting volumes of the Blekksprut prospect (Fig. 1.2 were deemed too low for an economic development. An AVO screening exercise was carried out on the existing seismic 3D volume, and concluded that also the large stratigraphic trap (Nori), located down flank from well 6710/10-1, was likely water bearing. A study of success factors for stratigraphic traps applied to this trap came out negative, In the success case most of the hydrocarbon volumes appear to be located outside the PL 601 license area. All other identified prospects in the license are too small to justify an exploration well.

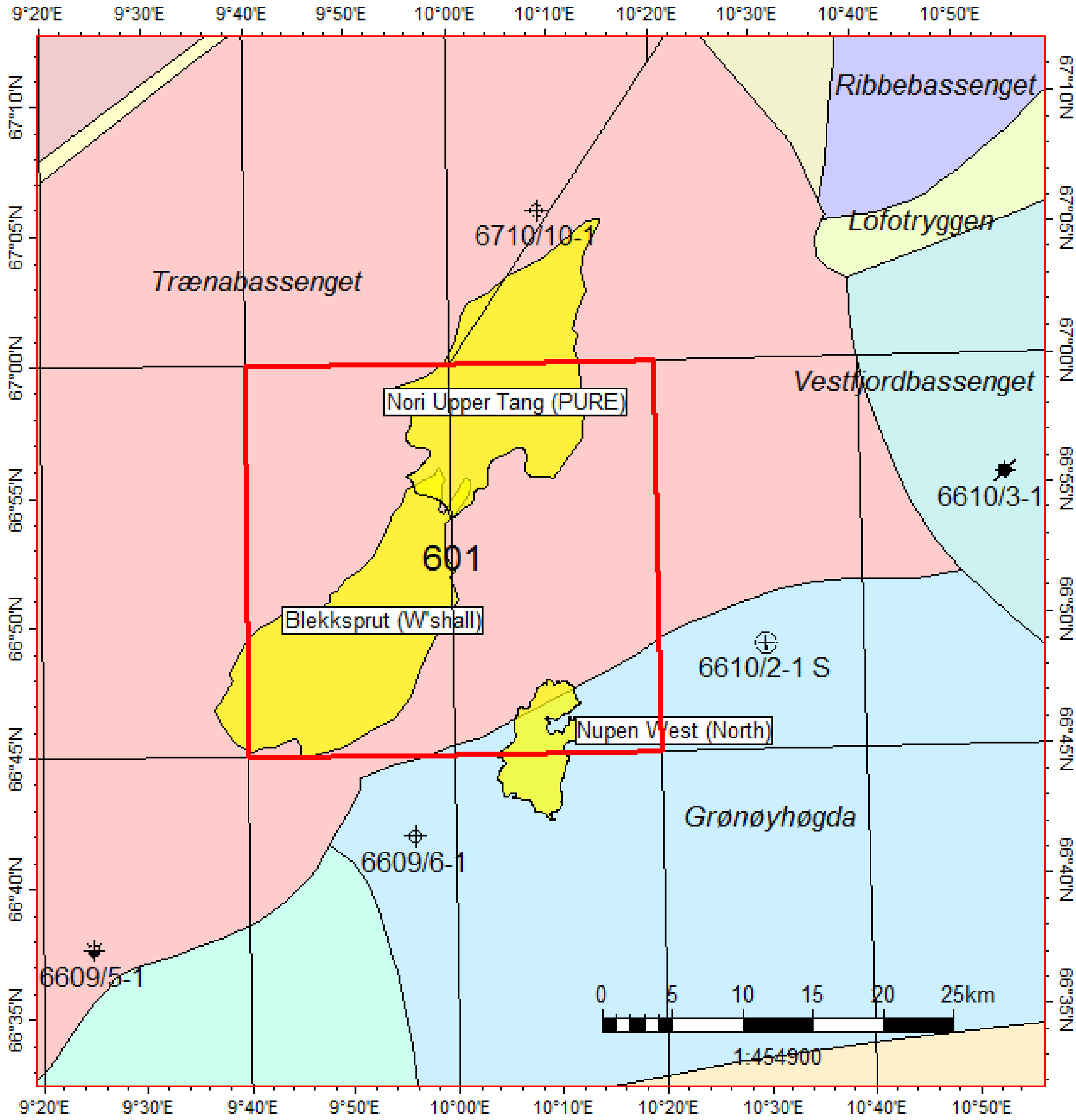


Fig. 1.2 PL601 Location Map

PL601 Location Map, highlighting the key prospects identified in the license

2 Database

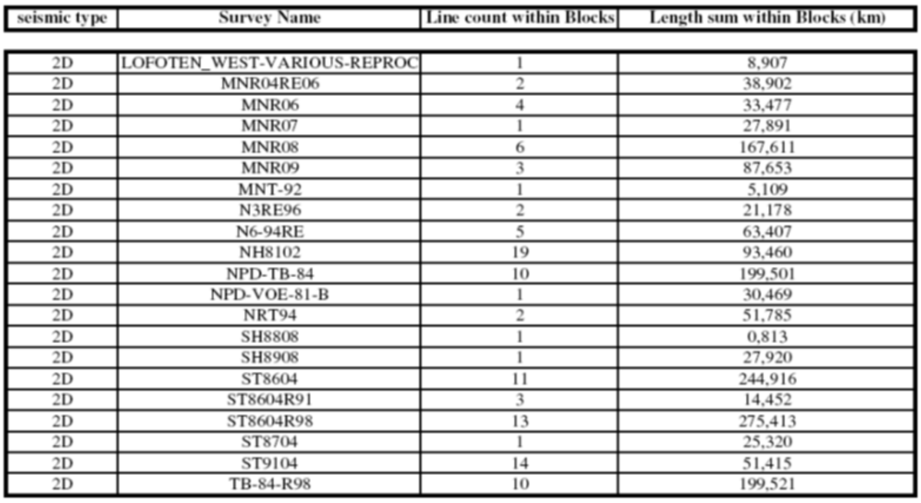
2.1 Seismic

The Common seismic database of the PL 601 license consisted originally of both 2D and 3D seismic data (Listing in Table 2.1 , Table 2.2 , maps Fig. 2.1, Fig. 2.2). The final outline of the 3D seismic database, after the WIN12002 data was acquired and merged with existing 3D surveys is shown in Fig. 2.3

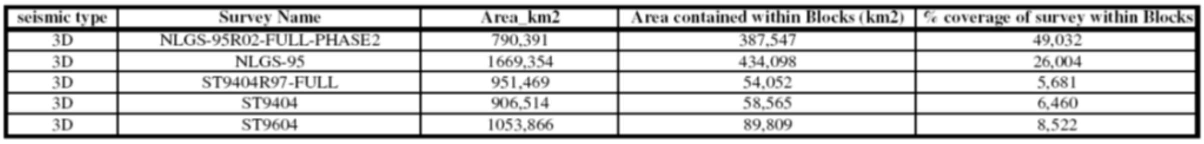
Table 2.1 PL 601 2D Seismic Database Listing

MNT-92-08-2	NH8102-449	ST9104-206	ST8604R98-482
	NH8102-450	ST9104-207	ST8604R98-484
N3RE96-ST8604-456	NH8102-451	ST9104-208	
N3RE96-ST8604-460	NH8102-452	ST9104-209	TB-84-R98-13
	NH8102-452A	ST9104-211	TB-84-R98-14
N6-94RE-101	NPD-TB-84-04	ST9104-401	TB-84-R98-15
N6-94RE-102	NPD-TB-84-05	ST9104-402	TB-84-R98-16
N6-94RE-103	NPD-TB-84-07	ST9104-403	TB-84-R98-17
N6-94RE-201	NPD-TB-84-08	ST9104-404	TB-84-R98-04
N6-94RE-202	NPD-TB-84-09	ST9104-405	TB-84-R98-05
	NPD-TB-84-09A	ST9104-406	TB-84-R98-07
NH8102-203	NPD-TB-84-13	ST9104-407	TB-84-R98-08
NH8102-203A	NPD-TB-84-14	ST9104-408	TB-84-R98-09
NH8102-204	NPD-TB-84-15	ST9104-409	
NH8102-205	NPD-TB-84-16	NRT94-001	LOFOTEN_WEST-VARIOUS-REPROC_1989-B-16-77B_GC
NH8102-206	NPD-TB-84-17	NTR94-002	
NH8102-206A	NPD-TB-84-17A		ST8604-246
NH8102-207		ST8604R91-464	ST8604-456
NH8102-207A	NPD-VOE-81-B-6-A-B__1	ST8604R91-472	ST8604-460
NH8102-207B	NPD-VOE-81-B-6-A-B	ST8604R91-476	ST8604-464
NH8102-208	NPD-VOE-81-B-6-B-C		ST8604-466
NH8102-208A		ST8604R98-240	ST8604-470
NH8102-208B	SH8808-270	ST8604R98-242	ST8604-472
NH8102-442		ST8604R98-246	ST8604-476
NH8102-442A	SH8908-101	ST8604R98-454	ST8604-478
NH8102-443	SH8908-101A	ST8604R98-456	ST8604-482
NH8102-443A		ST8604R98-460	ST8604-484
NH8102-444	ST8704-250	ST8604R98-464	
NH8102-445		ST8604R98-466	
NH8102-446	ST9104-203	ST8604R98-470	
NH8102-447	ST9104-204	ST8604R98-472	
NH8102-447A	ST9104-205	ST8604R98-476	
NH8102-448		ST8604R98-478	

Table 2.2 PL 601 2D and 3D Seismic Database Listing



seismic type	Survey Name	Line count within Blocks	Length sum within Blocks (km)
2D	LOFOTEN_WEST-VARIOUS-REPROC	1	8,907
2D	MNR04RE06	2	38,902
2D	MNR06	4	33,477
2D	MNR07	1	27,891
2D	MNR08	6	167,611
2D	MNR09	3	87,653
2D	MNT-92	1	5,109
2D	N3RE96	2	21,178
2D	N6-94RE	5	63,407
2D	NH8102	19	93,460
2D	NPD-TB-84	10	199,501
2D	NPD-VOE-81-B	1	30,469
2D	NRT94	2	51,785
2D	SH8808	1	0,813
2D	SH8908	1	27,920
2D	ST8604	11	244,916
2D	ST8604R91	3	14,452
2D	ST8604R98	13	275,413
2D	ST8704	1	25,320
2D	ST9104	14	51,415
2D	TB-84-R98	10	199,521



seismic type	Survey Name	Area_km2	Area contained within Blocks (km2)	% coverage of survey within Blocks
3D	NLGS-95R02-FULL-PHASE2	790,391	387,547	49,032
3D	NLGS-95	1669,354	434,098	26,004
3D	ST9404R97-FULL	951,469	54,052	5,681
3D	ST9404	906,514	58,565	6,460
3D	ST9604	1053,866	89,809	8,522

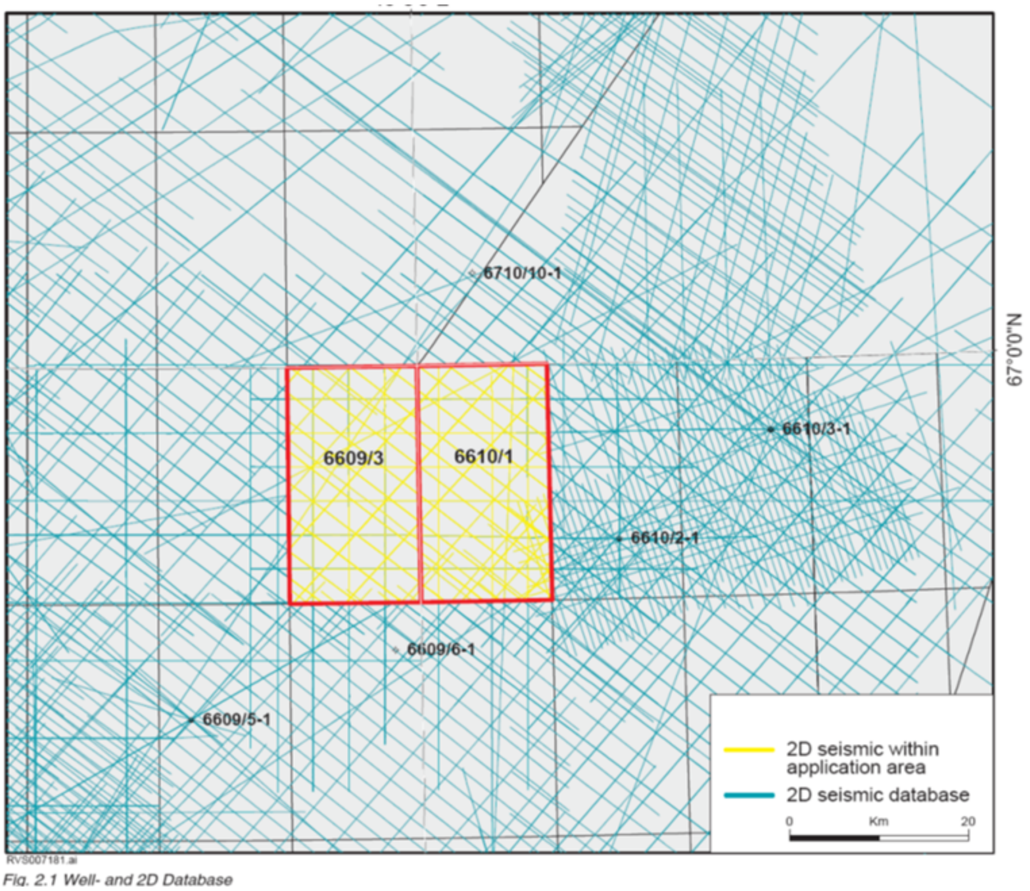


Fig. 2.1 Well- and 2D Database

Fig. 2.1 PL 601 2D Seismic Database Map

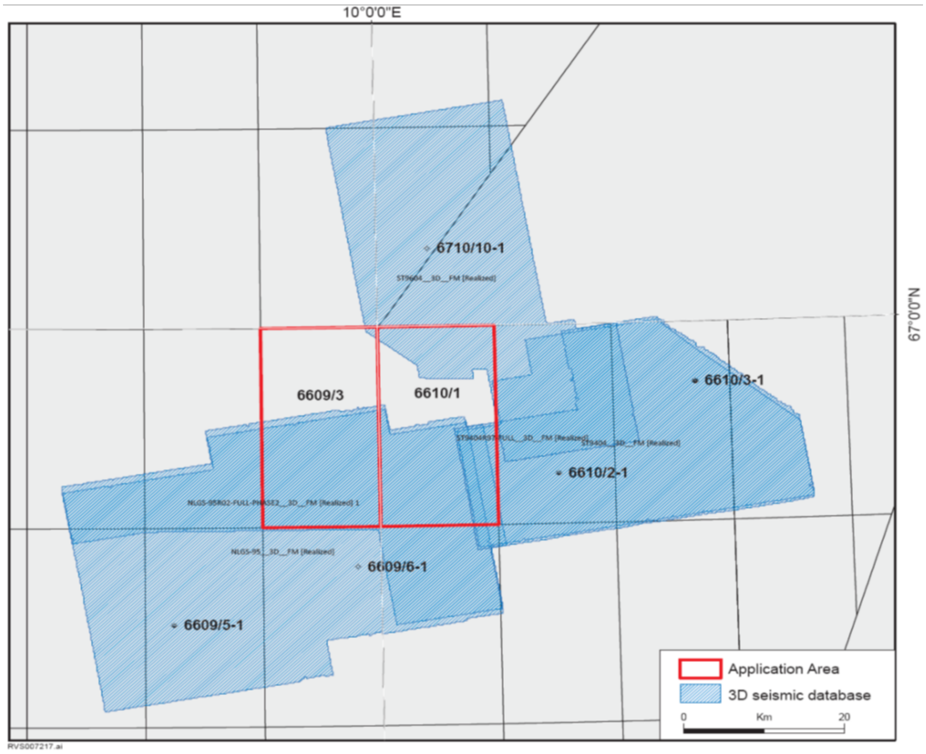


Fig. 2.2 3D Seismic Data base

Fig. 2.2 PL 601 3D Seismic Database Map

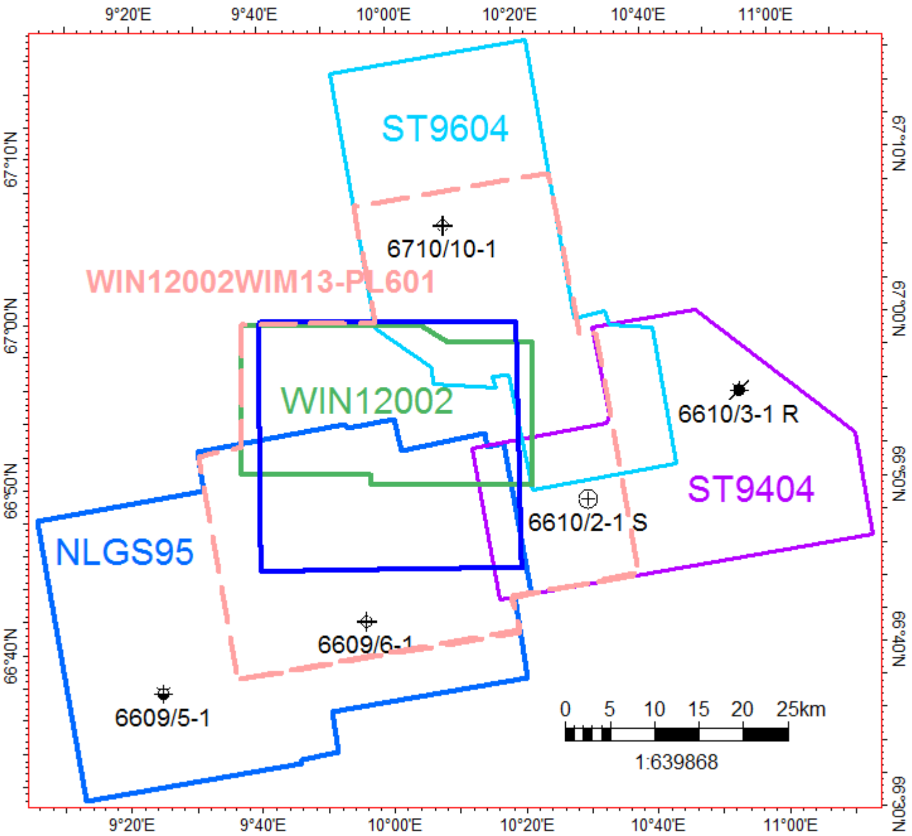


Fig. 2.3 PL 601 Final Outline of Common 3D Database

2.2 Wells

The common well database in PL 601 license comprise the five nearest offset wells, as illustrated in Fig. 2.4

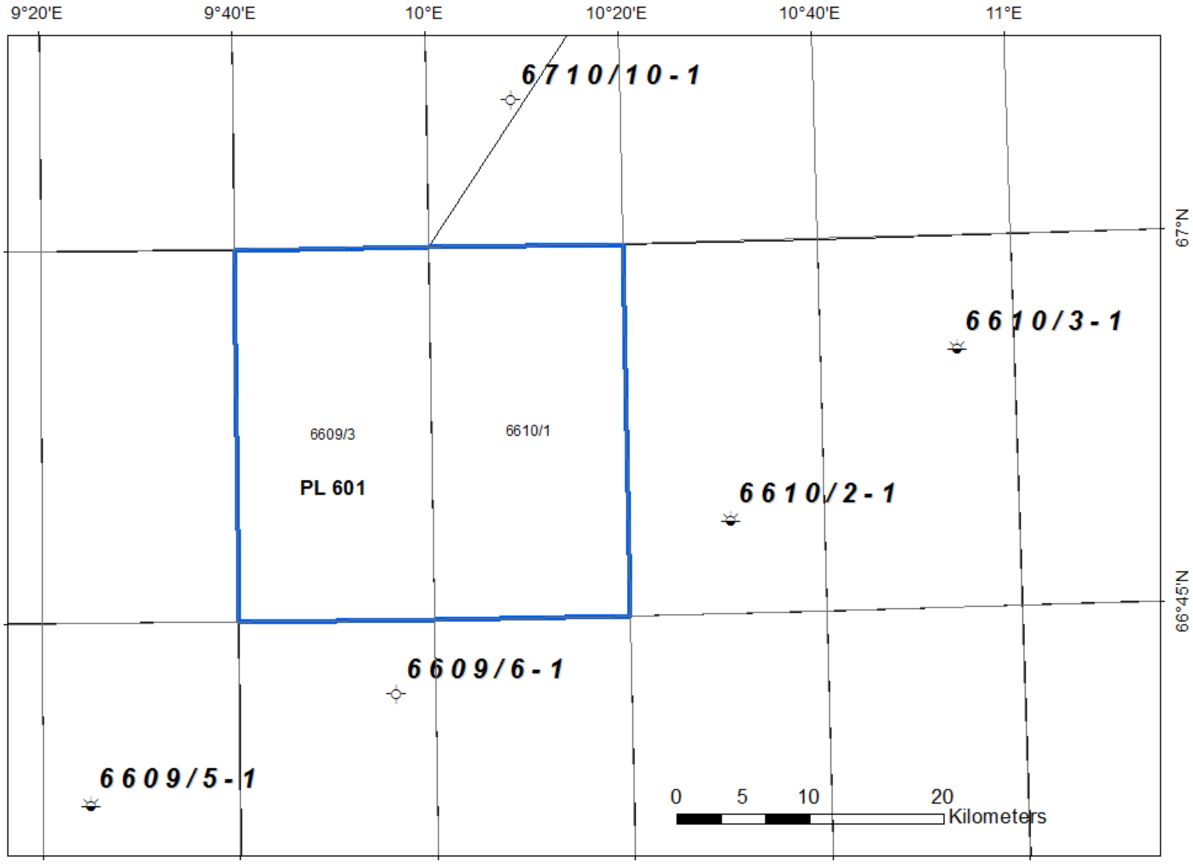


Fig. 2.4 PL 601 Well database

2.3 Studies

Key studies making up the PL 601 common database are listed in table 2.3.

Table 2.3 PL 601 Study database

StudyCompany	Company
Nordland Stratigraphic DB	Icron
FIS Outer Flanks Norwegian Sea	FIT

3 Geological petroleum overview

3.1 Seismic Mapping

Seismic Tie and Marker Interpretation

Synthetic seismograms were generated for the wells in the greater application area. The purpose was to tie and calibrate the key seismic horizons to the stratigraphic well tops. More details of the interpretation work is provided in Chapter 4.1. Well to seismic tie have subsequently been generated and the key seismic horizons have been correlated across the area of interest. The main focus of the Interpretation Work in PL 601 has been focussed on the Tertiary events, as the highest prospect potential is at these stratigraphic levels.

Below is a summary of the seismic markers that have been interpreted and used in the evaluation work of the PL 601 License Area Table 3.1 . The markers are described in some detail in Chapter 4.1.

Table 3.1 PL601 Interpreted seismic markers

Horizon	***Marker Quality***	***Comments***
Base Kai	Medium	Easy/ Medium marker to follow
Base Naust/ Top Brygge	Medium	Easy/ Medium marker to follow
Base Tertiary	Good	Easy Marker to follow
Near Top Tare (called "1")	Medium	Low amplitude event. In places conjectural
Near Top Tang (called "2")	Medium	Low amplitude event. In places conjectural
Intra Tang 3 ("3")	Good	High amplitude event, fairly consistent across the high
Intra Tang 4 ("4")	Good	High amplitude event, fairly consistent across the Grønøy high
Intra Tang 5 ("5")	Medium	Mixed amplitude response. In places conjectural
Top Springar	Medium/ Difficult	Low amplitude, "woolly" expression, improved in the swath re-processing
Top Lysing	Medium	Easy to pick close to boundary faults. Reprocessing has extended the interpretability further into the Træn Basin
Intra Lange	Medium	Easy to pick close to boundary faults. Reprocessing has extended the interpretability further into the Træn Basin
Base Cretaceous	Medium	Marker can be hard to follow across the Grønøy High area, due to varying acoustic contrast
Intra Coal Marker	Medium	The high amplitude coal events makes the intra Åre seismic pick reasonably confident

Time to Depth Conversion

Time to depth conversion has been carried out using the Aker Geo velocity cube, which gives a good correspondence to well marker depths.

3.2 Regional Geology

PL 601 is situated in an area where the major ingredients of a working petroleum system, namely presence of both reservoirs and migrated hydrocarbons, has been proven. In fact, the five wildcats in the area proved Cretaceous and Paleogene viable reservoirs with hydrocarbon shows at different stratigraphic levels (e.g., Well 6610/3-1, with oil shows in Paleocene and Cretaceous sediments). With only five penetrations, this area is virtually un-explored (Fig. 3.1). Key reservoir objective, the Paleocene sequence, is locally present with a large thickness, but shows significant thickness and quality variation (Fig. 3.2).

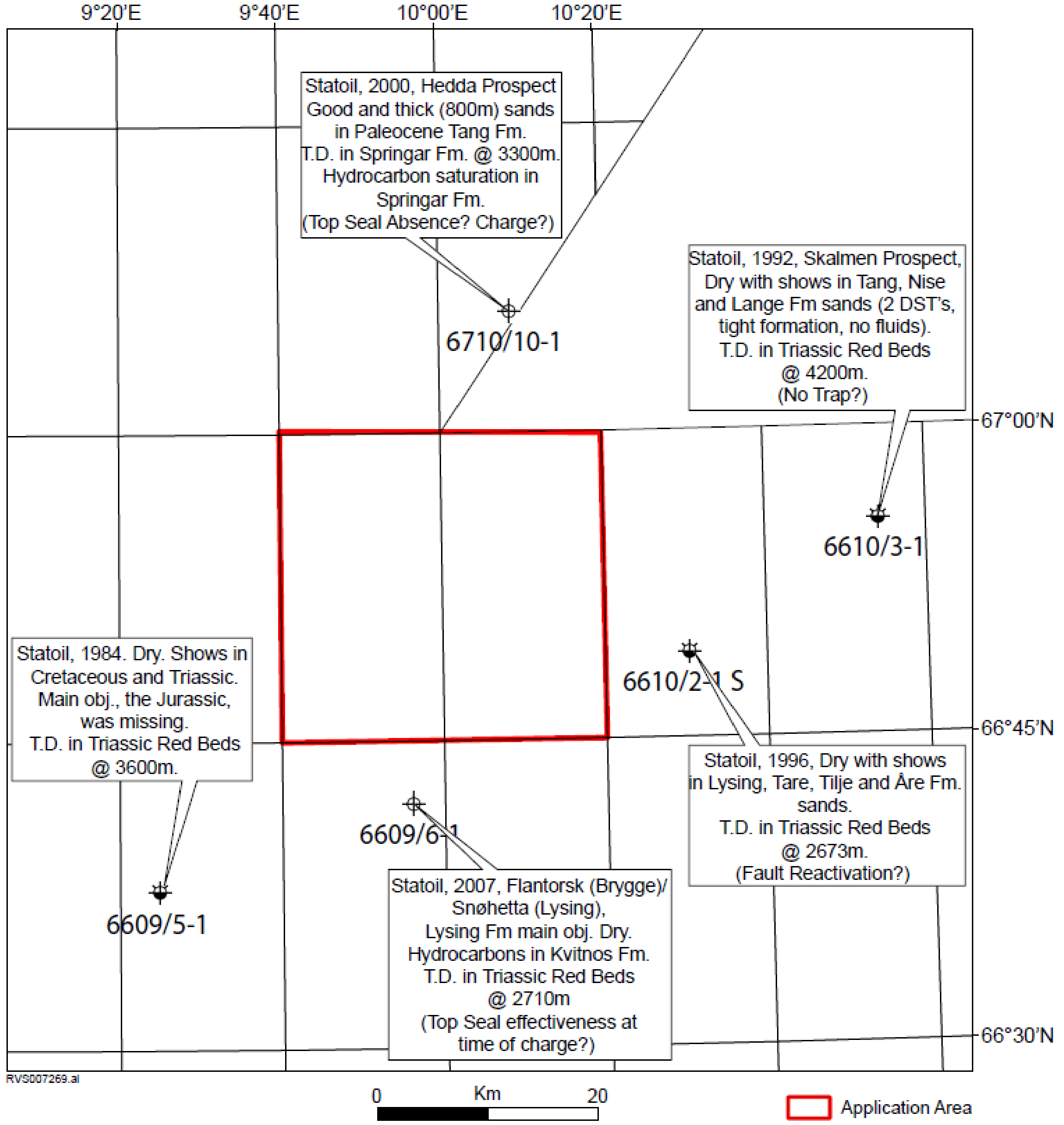


Fig. 2.3 Well Post Mortem, Nordland III

Fig. 3.1 PL 601 Summary results of offset wells

The key observation is that ample HC shows were encountered in the wells. The wells failed to find movable hydrocarbons for reasons of

a. Invalid trap (6610/2-1S, 6610/3-1R(?))

b. Poor reservoir (6609/5-1, 6609/6-1), and

c. Charge (6710/10-1)

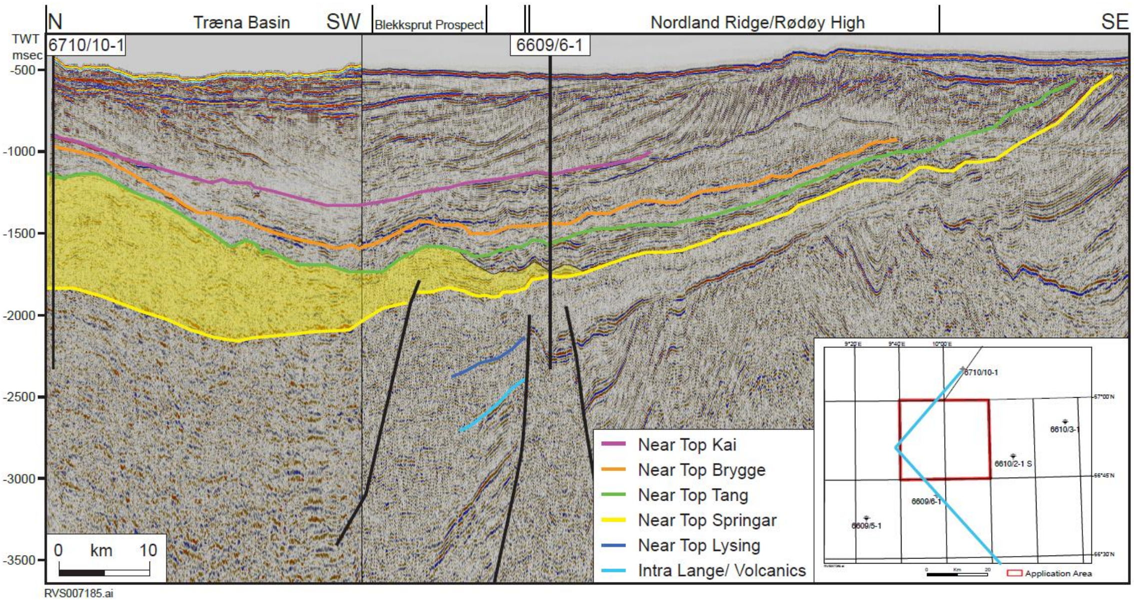


Fig. 3.2 Seismic Cross Section across the Træn Basin

The cross section illustrates the persistent location of sand accommodation area, resulting in a large thickness of Eocene/ Paleocene clastics package that quickly thins towards the area of well 6609/6-1

The key prospects are structural closures located within a domal structure, or coincide with gas-vent high, in addition to stratigraphic trap at the flan of the 6710/10-1 high. All prospects are favourably located with respect to hydrocarbon charge (Fig. 3.3).

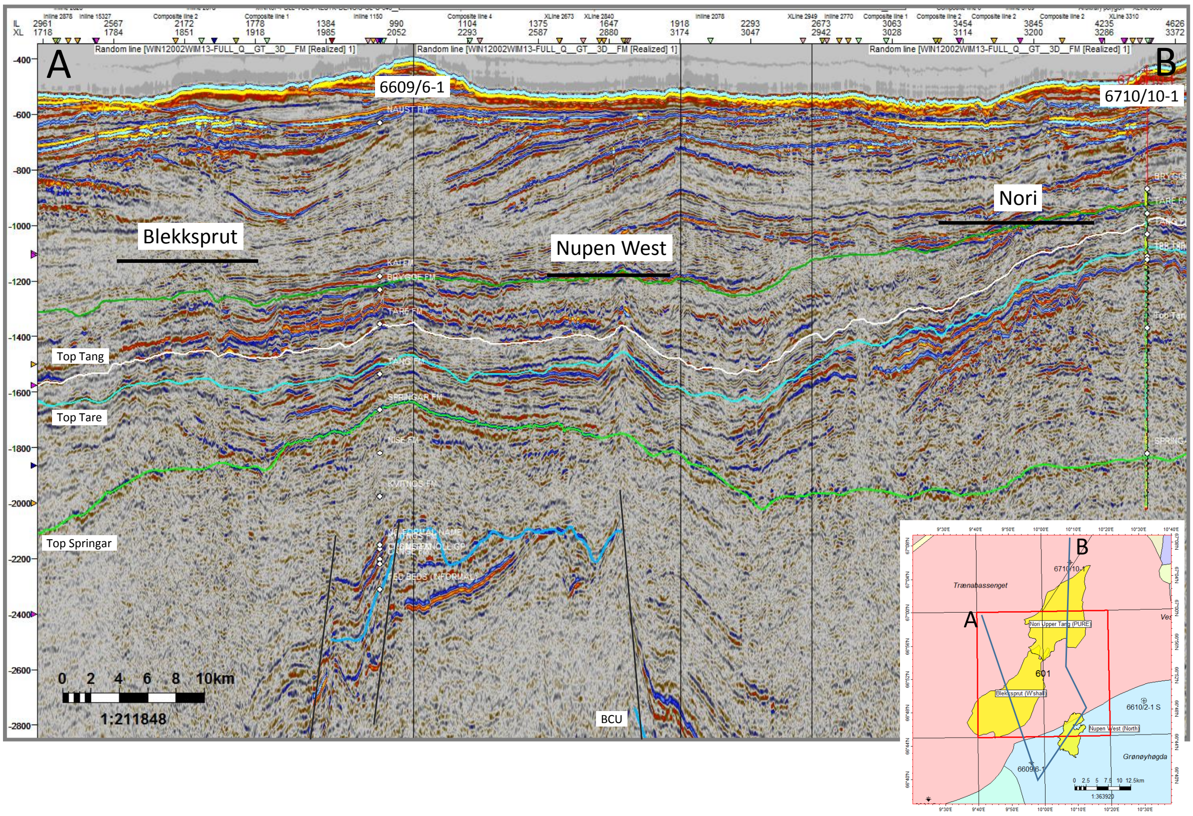
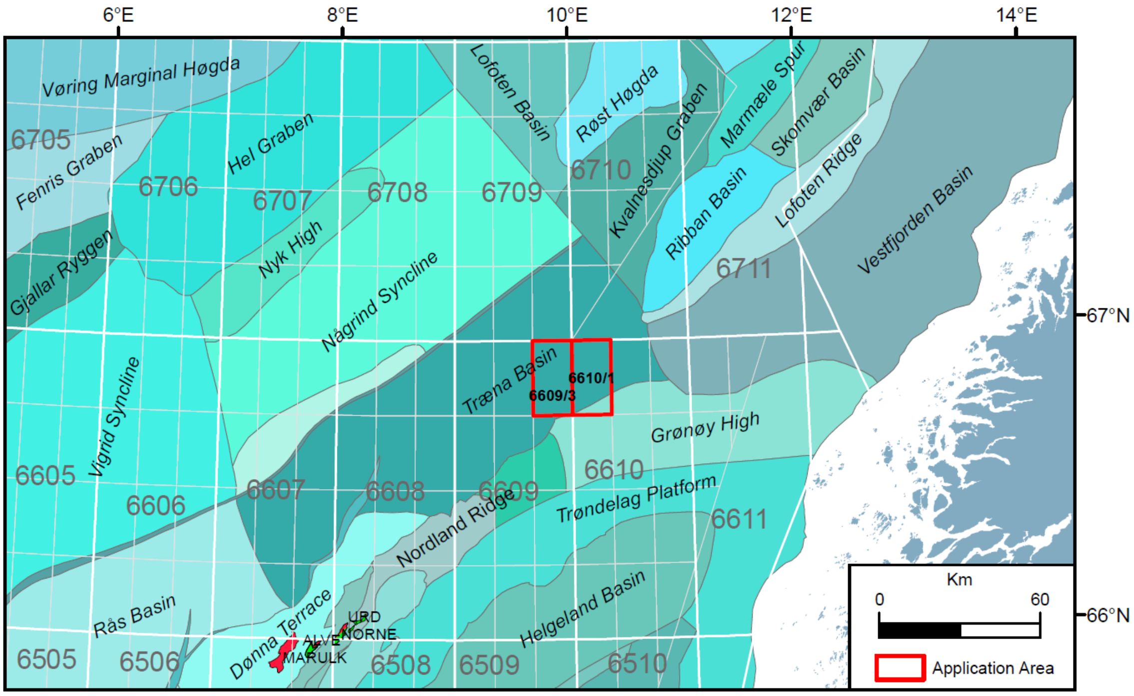


Fig. 3.3 Main Prospects PL 601 license

The transect shows the location of the key prospects in the PL 601 license. It also illustrates the thickness variation of the Eocene/ Paleocene section

The license sits in the Træna Basin, at the transition with the Vestfjorden Basin, and are situated between the Nordland Ridge/Rødøy High to the south and the Lofoten Ridge/Ribban Basin to the north (Fig. 3.4; Fig. 3.5). These two structural highs are important because they controlled, at the semi-regional scale, the deposition of reservoir, seals and source rocks.



RVS007168.mxd

Fig. 3.4 Major Strucutral Elements and Location of PL 601

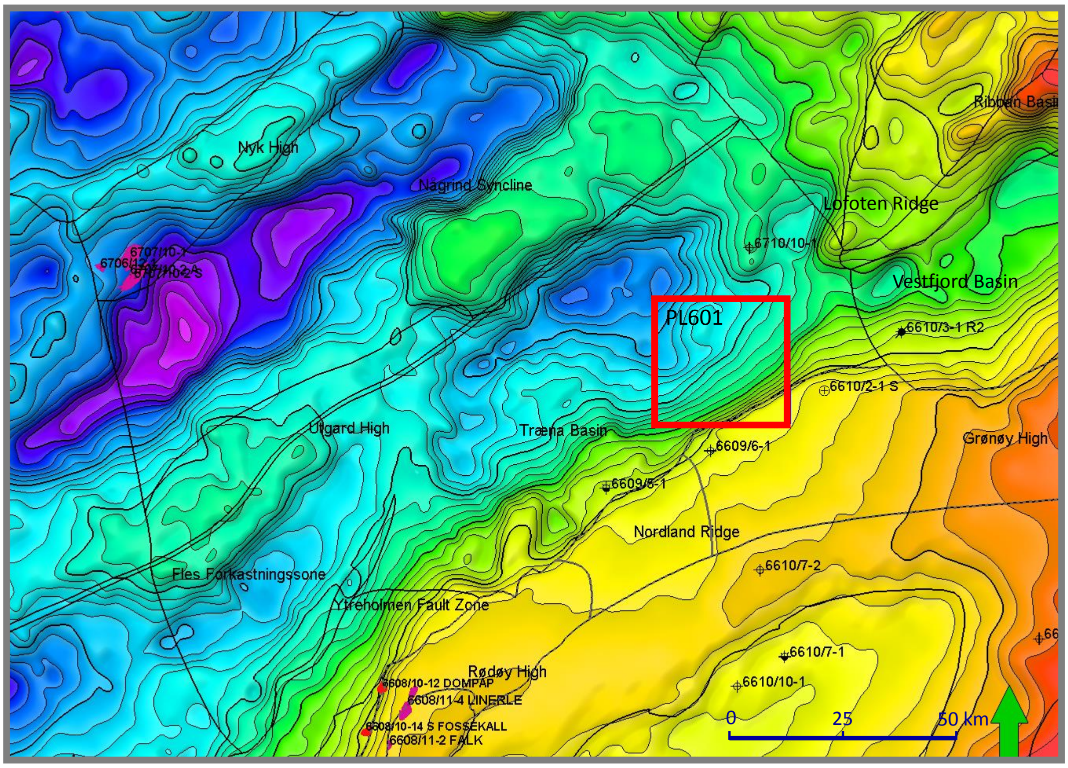


Fig. 3.5 View of Norwegian Sea Structural Elements

Trænabanken area regional structures Illustrated on a BCU 2wt map. The bulk of the PL 601 area is located in the Træna Basin

The Lofoten Ridge is part of the larger Lofoten-Vesterålen Margin and comprises the oldest basement rocks on the Norwegian Shelf and mainland, represented by magmatic gneisses and granulites (2700 Ma), granites (1380 Ma), and schistes (1140 Ma) (Griffin et al., 1978), and constitutes the predominant source area for Mesozoic (?) and Paleogene sands in the Træna- and Vestfjorden basins. Apatite Fission Track studies from Andøya and Vesterålen indicate Paleozoic, Jurassic, Cretaceous, Miocene and Pliocene phases of uplift and erosion.

The Nordland Ridge/Grønøy High comprises Permo-Triassic rocks, and represents the structural element buffer to the south for Paleogene turbidite systems sourced from the north (e.g., Lofoten Ridge). A sedimentary contribution from the Nordland Ridge/Grønøy High structural elements during the Paleogene is not excluded, although interpreted to be minimal in comparison to what derived from the Lofoten Ridge.

An important structural feature, the Bivrost fracture zone (or transfer system), runs NW - SE trough these blocks. The Bivrost Lineament separates the northern Vøring Basin and Vøring Marginal High to the south from the Lofoten-Vesterålen Margin to the north (Eldholm et al., 2002). It is interpreted to represent a dextral shift in the major structural elements and rejuvenated during several tectonic episodes (Blystad et al., 1995), likely reflecting a change in continental crust architecture and composition at depth (Kodaira et al., 1998), but also an original Caledonian zone of crustal weakness linked to the Nesna Detachment (shear) Zone on land, and a transfer zone during the Mesozoic and Tertiary (Ebbing et al., 2006). Although difficult to quantify, the re-activation of this zone during the various tectonic episodes is important for shaping/re-arranging of the Træna Basin, changing of the sediment source areas, opening/ closing of fracture systems and consequent hydrocarbon migration, and emplacement of volcanic sills.

At the larger scale, the tectono-sedimentary development of these basins and highs can be seen in relation to the plate tectonics movements and organisation during the Upper Paleozoic, Mesozoic and Tertiary. The following tectonic events are linked to the development of the key elements of the petroleum system:

Permo-Triassic extensional movements (Proto-Rift Phase) following the Caledonian orogeny, with continental deposition (Grey and Red Beds formations) of sandy reservoirs as well as of source rocks (Åre Formation). Jurassic Pre-Rift phase, with deposition of prevailing shallow marine sands and shales (Båt and Fangst Groups).

Late Jurassic - Early/ Middle Cretaceous stretching of the continental crust (Syn-Rift Phase), with subsequent development (Post-Rift Phase) of basin filled with marine shales and sandstones, representing both reservoirs (Lange and Lysing formations), as well as source rocks (Spekk Formation, and possibly Lower Cretaceous source intervals).

Late Cretaceous anticlockwise rotation of the Greenland Plate (following the opening of the Labrador Sea to the west), with faulting of Cretaceous units and uplift of the Vesterålen - Lofoten area. Abundant sediments were sourced from this area into the Træna Basin during the Latest Cretaceous and Paleogene, within submarine fan systems yielding mass gravity sandstones with reservoir potential (Springar and Tang Formations). Eocene Atlantic break up, subsequent formation of Atlantic oceanic crust, and with volcanic intrusions and associated hydrothermal vents in the area of PL 601 is very likely associated with reactivation of the Bivrost Lineament. These vents might have affected the petroleum system of the PL 601 area by forming pathways for fluid (including hydrocarbons) movement. During this period the locally sand rich Tare Formation was deposited, rich in volcanic ash layers.

Eocene-Oligocene change of direction of continental plates' movement and formation of oceanic crust along the western margin of the Barents Sea. Consequently, the Nordland area became a passive margin with deposition of shales and silica-oozes of the Brygge Formation.

Late Oligocene to Middle Miocene doming in the more westerly Atlantic areas, is also affecting, although at a minor scale, the Nordland area, with likely uplift of the of the basin flanks along the landward parts of the margin, and is linked to a general uplift of the Fennoscandian Shield. This event caused the deposition, during the Late Miocene - Early Pliocene, of the Molo/Kai Formations, the first represented by quartzose and glauconitic sands deposited by shelf progradation in a wave-dominated environment, with extensive long-shore drift (Eidvin et al., 2007). The Kai Formation represents the offshore coeval marine shales. In the PL 601 area the Eocene/ Oligocene doming is responsible for the overall trap styles as well as for affecting the hydrocarbon charge system, causing (re-)migration of hydrocarbons along newly open fracture pathways.

Pliocene - Pleistocene is characterized by westward-prograding siliciclastic systems (Naust Formation), likely related to a tectonic episode and overall climatic deterioration culminating in glacial episodes (Rasmussen et al., 2008). Late uplift and subsequent erosion of 200 - 500 m (Mid Miocene - Pliocene), as inferred by modelling of AFTA and vitrinite data, is documented in the Study Area but outside the PL 601 area.

The major Play Model in the PL601 area is Paleogene marine mass gravity flow sandstones of the Tang Formation, sourced by the marine shales of the Upper Jurassic Spekk Formations and/or by Cretaceous marine shales (Lange/Lysing/Nise formations).

Additional plays are the Eocene Tare Formation sandstones, the Cretaceous sandstones of the Lysing, Lange, Nise and Springar formations as well as the facies linked to the Paleogene volcanic intrusions within the Cretaceous sedimentary package. Critical to Cretaceous (and older) play models is the reservoir quality in the PL 601 area as a consequence of primary facies, mineralogy and depth of burial.

Reservoir Development and Quality

This chapter will mostly deal with the Paleogene Tang Formation and the Cretaceous Springar Formation, as these are the expected main reservoirs within the mapped prospects Fig. 3.6. The Paleogene Tang Formation in the area of interest consists of mass-gravity flow sandstones and associated marine shales. Where these sandstones are cored (e.g., Wells 6710/10-1 and 6610/3-1), they show sedimentary features indicative of deposition by debris- and turbidite flows as well as by associated slumping and sandy injections (Fig. 3.7). These sandy deposits were likely sourced from the Lofoten Ridge to the north, and organised in one major fan system (or more associated), some 100 km wide in the west-east direction (Fig. 3.8). This depositional system typically abutts and onlaps, in the offered Blocks, onto the Grønøy High/Nordland Ridge to the south. Wells located on the prominent Nordland Ridge (e.g., 6609/6-1) do not yield (Paleocene) sandstones of interesting thickness and reservoir quality. Similarly, sandy intervals within the Tang Formation package seem to diminish further to the southwest (e.g., well 6609/5-1) (Fig. 3.9). This has been interpreted to be indicative of either areally-limited depositional system and/or presence of structural control (i.e., the Nordland Ridge). Illumination of the seismic data (Geoteric) at Lower Tare/ Upper Tang level indicates a sand source located to the north of the PL 601 license area. Lofoten Ridge appears to be a strong candidate. Some sinuous patterns in the south may point towards a southern source as well (Fig. 3.10). The associated marine shales represent depositional stillstands within the sandy pulses. These possibly laterally extensive shales act as both intra-formational baffles and top seals.

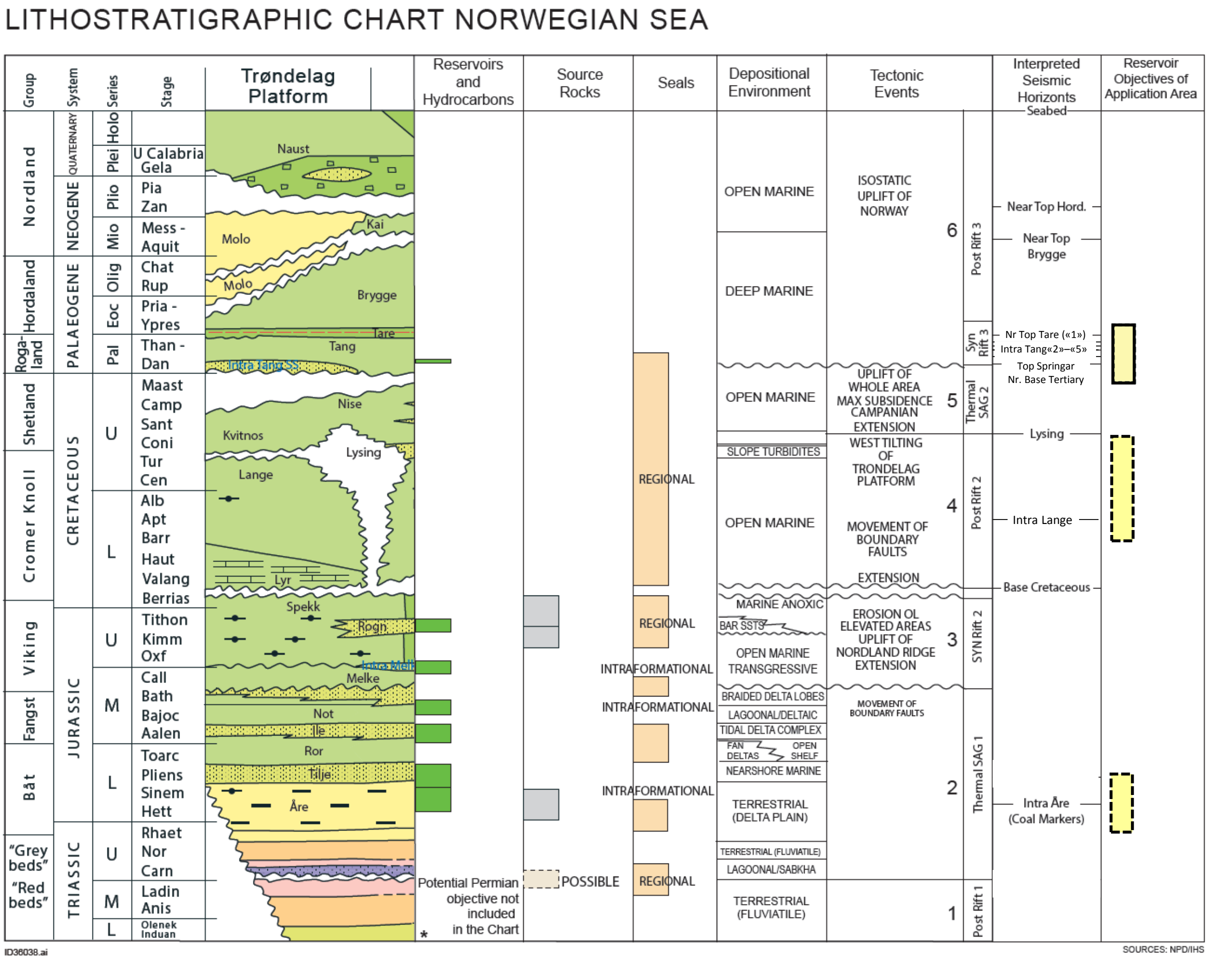


Fig. 3.6 Stratigraphic Framework Norwegian Sea

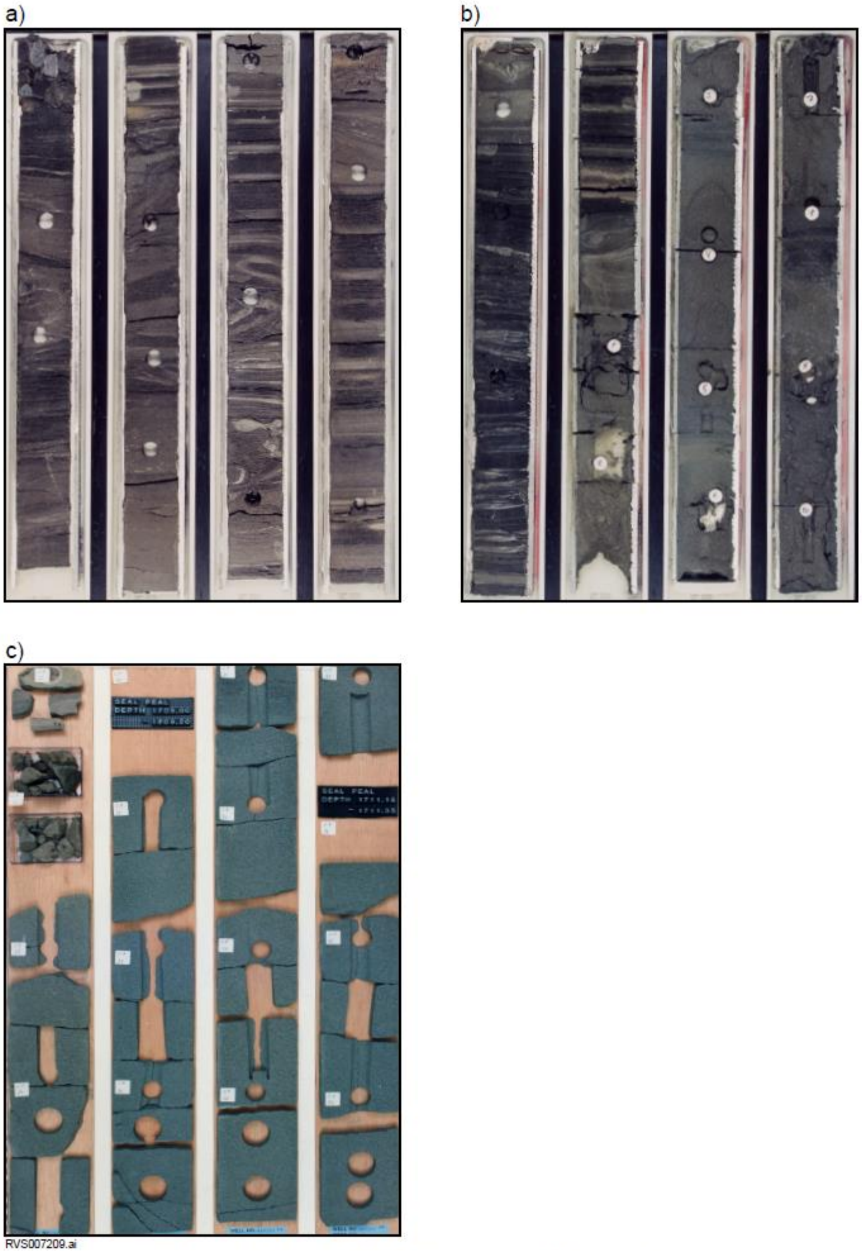


Fig. 3.7 Tang Formation, Cores from Wells 6710/10-1 and 6610/10-3
Sedimentary features are indicative of deposition by sandy debris flow and high/ low density turbidite flow, also including syn/post depositional slumps and injectites. Cores a) and b) are from well 6710/10-1, and core c) is from well 6610/3-1

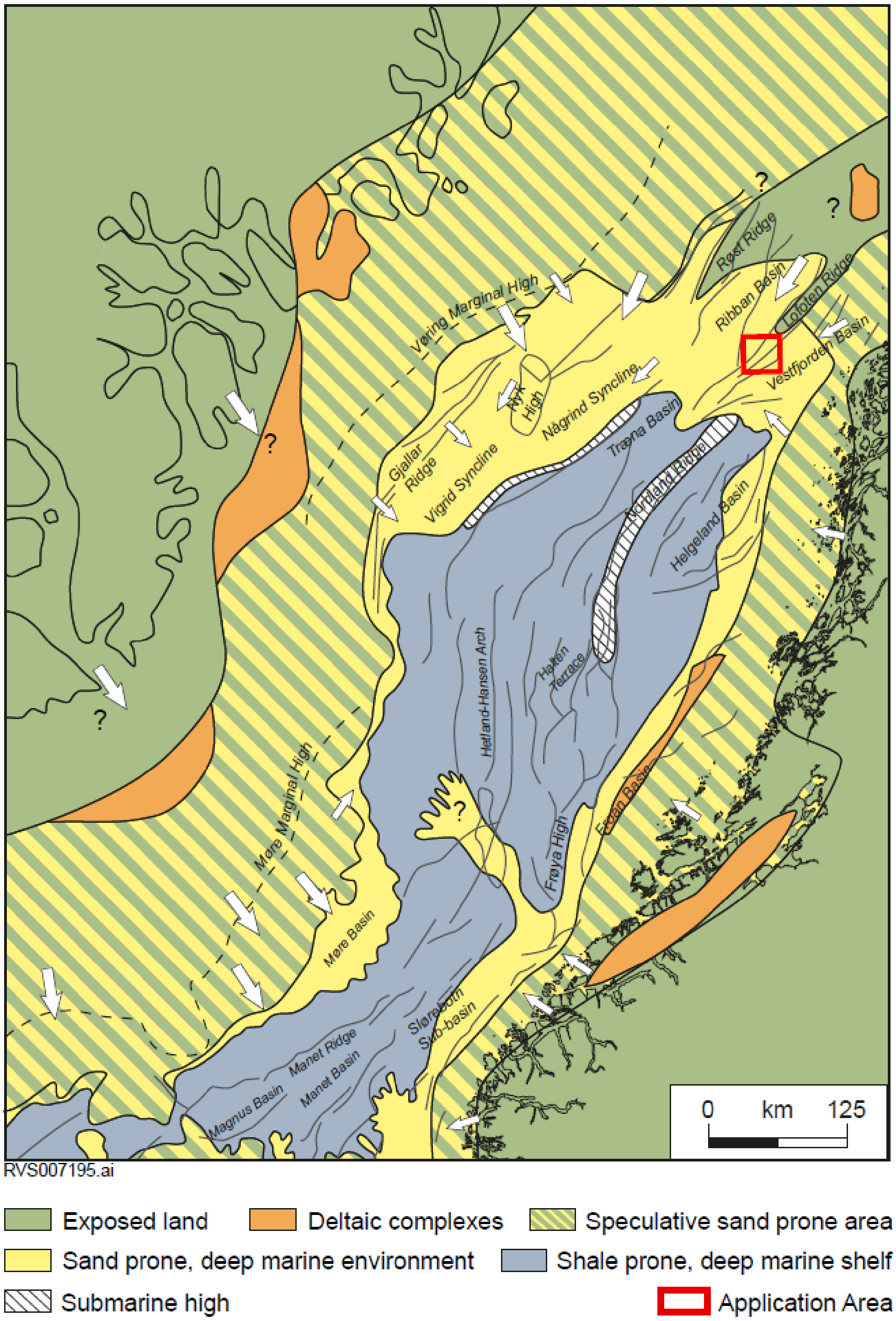


Fig. 3.8 Paleogene Paleogeography of the Norwegian Sea

Main sand fairways are shown. PL 601 sits in an area characterized by a sand fairway during the Paleogene. White arrows indicate sediment transport direction

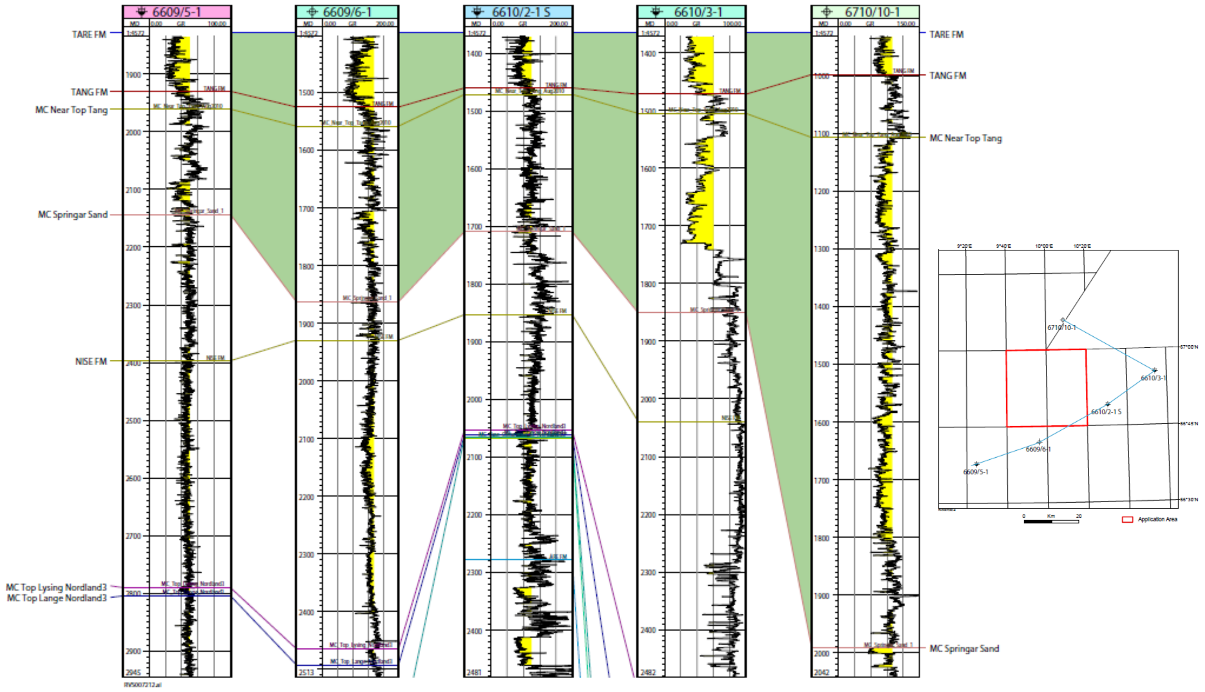


Fig. 3.9 Well Correlation showing Thickness Increase

Shows the Paleocene package from SW to NE. Also note increase in Paleocene sandy intervals of the Tang Formation along the same direction

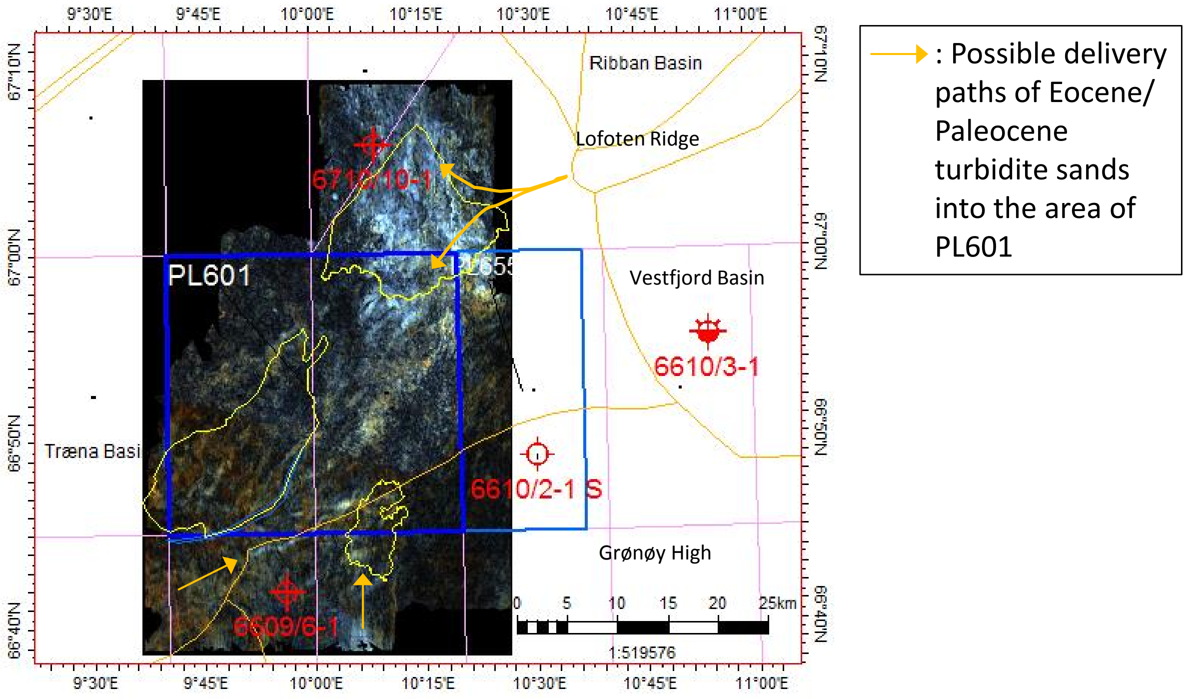


Fig. 3.10 PL 601 Lower Tare/ Upper Tang Geoteric Illuimination Map

The display illustrates that the main accommodation space at this time was straddling into the PL 601 area from the north. However, a possible southern source area can also be envisaged

The sandstone reservoir quality is commonly medium to good although variable within the study area, being dependent upon primary depositional facies and mineralogy. In-house CPI analyses of the five relevant wells in the area (e.g., Fig. 3.11, well 6710/10-1). indicate porosity of 18% to 26% (and associated permeability of tens to hundreds of mD) for the Tang Formation sandstones. Depth of mapped prospects in Blocks 6609/3 and 6610/1 is 1500 - 2000 m. This would corresponds to porosities in the 16 - 30% range, with corresponding permeabilities of 100 mD plus (Lien et al., 2006) in the best depositional facies. By analogy with the North Sea Paleocene fields, it is assumed that turbidite channel and lobe facies (or massive sandy debrite bodies) would yield the best reservoir quality. Yet, core well data points (as well as seismic data coverage and quality) in the study area are too limited to define the 3D facies organisation and associated reservoir properties of the main fan system(s). Depth of burial is not considered to be of importance with regards to reservoir quality degradation in the PL 601 area, since the maximum depth to target is 2000 m MSL (1600 m overburden thickness).

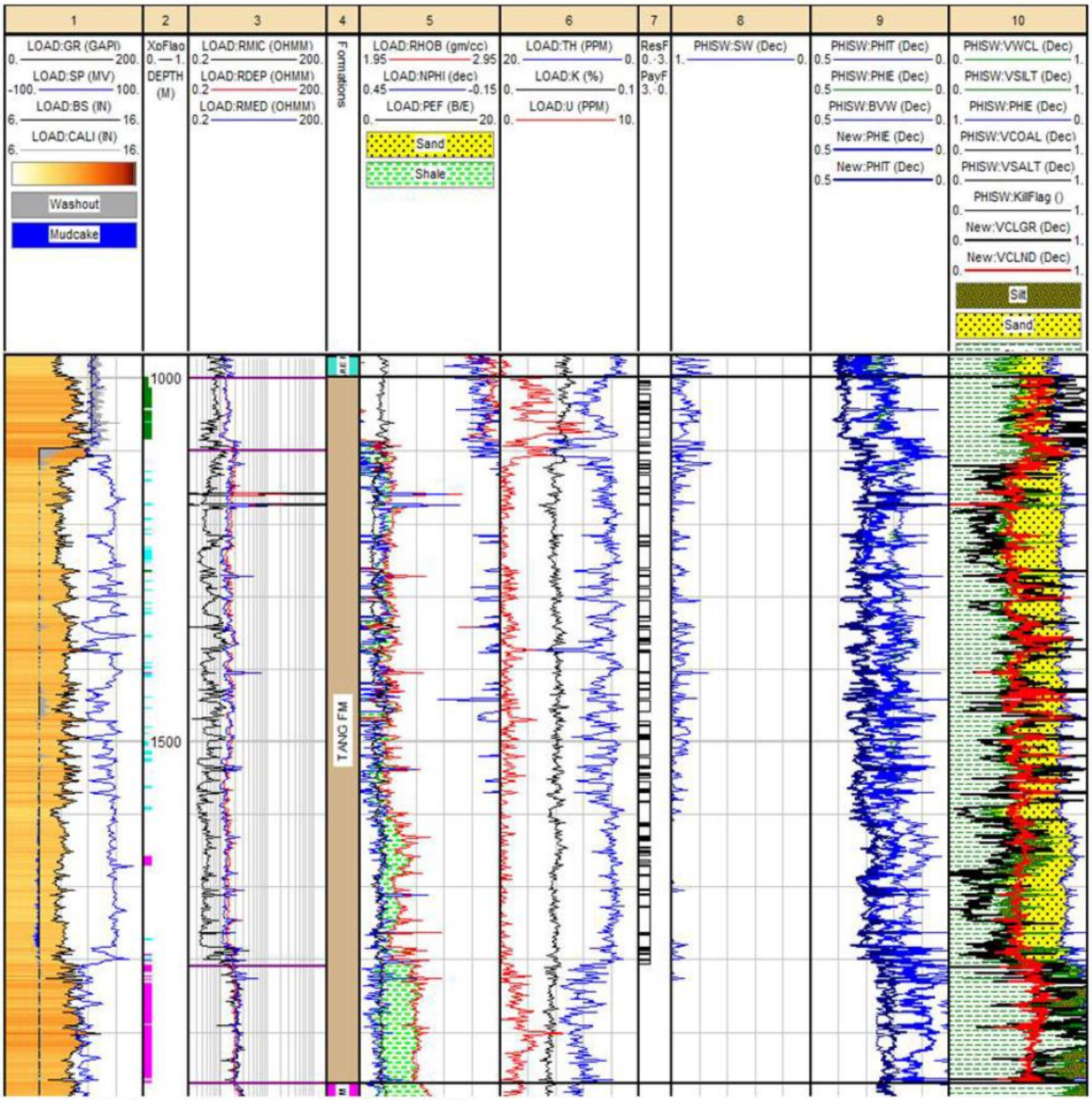


Fig. 3.11 CPI Analysis of the Tang Formation, Well 6710/10-1

Marine sandstones of the Springar Formation, likely deposited by mass gravity flows, have also been penetrated in the offset wells (6610/2-1S; 6610/3-1(R); 6710/10-1). Their relative thickness and measured reservoir quality is moderate (e.g. in well 6610/2-1S, Springar sands have porosity of 16%, but N/G of 11%). These sands represent an additional upside, if facies with better reservoir properties are developed. Typical of these mass gravity flow systems is their three-dimensional facies organisation of sandstones and shales, with rapidly changing lateral and vertical facies (often with injectites) and hence the associated porosity and permeability data. The understanding of this spatial organisation is crucial to well planning and field development purposes for optimizing production and recovery efficiency (see e.g., Hempton et al., 2005).

The facies organisation and reservoir quality of these sandstones is expected to be similar to what was reported by Møller et al., 2004; Lien et al., 2006; Martinsen et al., 1999 and Martinsen et al., 2005, in other parts of the Norwegian Sea, as well as from age-equivalent deposits of the North Sea (Bergslien et a., 2005; Hempton et al., 2005). The available data points within in the study area are however still too few and far apart to allow for firm conclusions on this matter.

3.3 Basin Development

Source Rock Presencce and Quality

The source rocks in the Norwegian Sea have historically been considered to be mainly of Jurassic age. The Upper Jurassic Spekk Formation is the principal source rock for the petroleum system at the Halten and Dønna terraces. Additional contribution from Melke Formation and the Lower Jurassic Åre Formation is found in petroleum discoveries on Dønna - Halten terraces and Frøya High (Cohen & Dunn, 1987; Ellenor & Mozetic, 1986; Elvsborg, Hagevang & Throndsen, 1985; Hvoslef, Larter & Leythaeuser, 1988; Karlsen et al., 1995; Khorasani, 1989; Odden et al., 1998; Whitley, 1992). The main source rocks, Spekk, and Melke and Åre formations are extensively described in Karlsen et al., 1995. Richness and quality of Jurassic SR intervals are summarised in Fig. 3.12, SR richness in Table 3.2 and depositional environment in Fig. 3.13. The data highlights the marine characteristics of Spekk, with very high TOC values, often exceeding 8 wt% (Table 3.2).

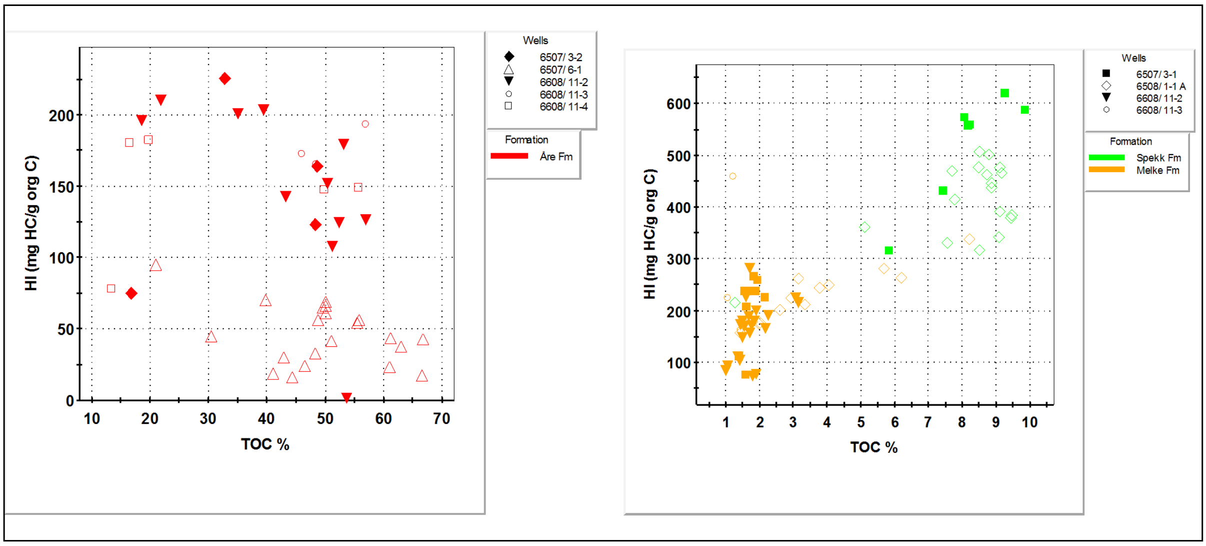


Fig. 3.12 Jurassic Source Rocks Richness and Quality
The data shows that in the area of PL 601 Spekk is the dominant SR for oil

Table 3.2 SR thickness

6507/3-1	3088	34	3122	486	3976	781
6507/3-2		0		0	1274	506
6507/3-3	3013	80	3093	271	3680	150
6507/3-3 A	3098	60	3158	631		0
6507/3-3 A		0	4147	381		0
6507/3-3 B	3098	60	3158	634		0
6507/3-4	3161	24	3185	540	4047	45
6507/3-5 S	3566	4	3570	390	4216	49
6507/3-6		0		0	1422	228
6507/3-7	3344	19	3363	182	3785	70
6507/3-8	2534	51	2585	108		0
6508/1-1 A	2573	165	2738	123		0
6508/1-1 S	2130	17	2147	204	2714	36
6608/10-1	2920	8	2937	124	3218	219
6608/10-1	2934	3		0		0
6608/10-10	2365	11	2376	29	2567	233
6608/10-11 S	3107	46	3153	327		0
6608/10-12	2674	3	2677	11	2770	290
6608/10-12 A	2768	9	2777	21	2934	141
6608/10-13		0		0	1281	161
6608/10-14 S	2375	6	2381	52	2592	288
6608/10-2	2347	18	2365	213	2819	859
6608/10-3	2407	6	2413	161	2791	130
6608/10-3 R	2407	6	2413	161	2791	130
6608/10-4	2328	44	2372	112	2697	103
6608/10-4		0	2533	34		0
6608/10-5	2634	3	2637	114	2791	409
6608/10-6		0	1794	20	1873	242
6608/10-6		0	1850	9		0
6608/10-6 R2		0	1789	20	1868	240
6608/10-6 R2		0	1845	9		0
6608/10-7		0	1902	46	2018	301
6608/10-8	2222	2	2224	70	2403	249
6608/10-8		0	2341	7		0
6608/10-8 A	2323	22	2345	89		0
6608/10-8 A		0	2520	11		0
6608/10-9	2047	8	2055	78	2228	172
6608/11-1		0		0	1233	85
6608/11-2		0	1614	91	1736	328
6608/11-3		0	1444	33	1530	410
6608/11-4		0		0	1668	485
6608/11-5		0		0	1550	91
6608/11-6		0	1500	51	1630	220
6610/2-1 S		0		0	2278	263
6610/3-1 R	3534	80	3614	91	3935	212

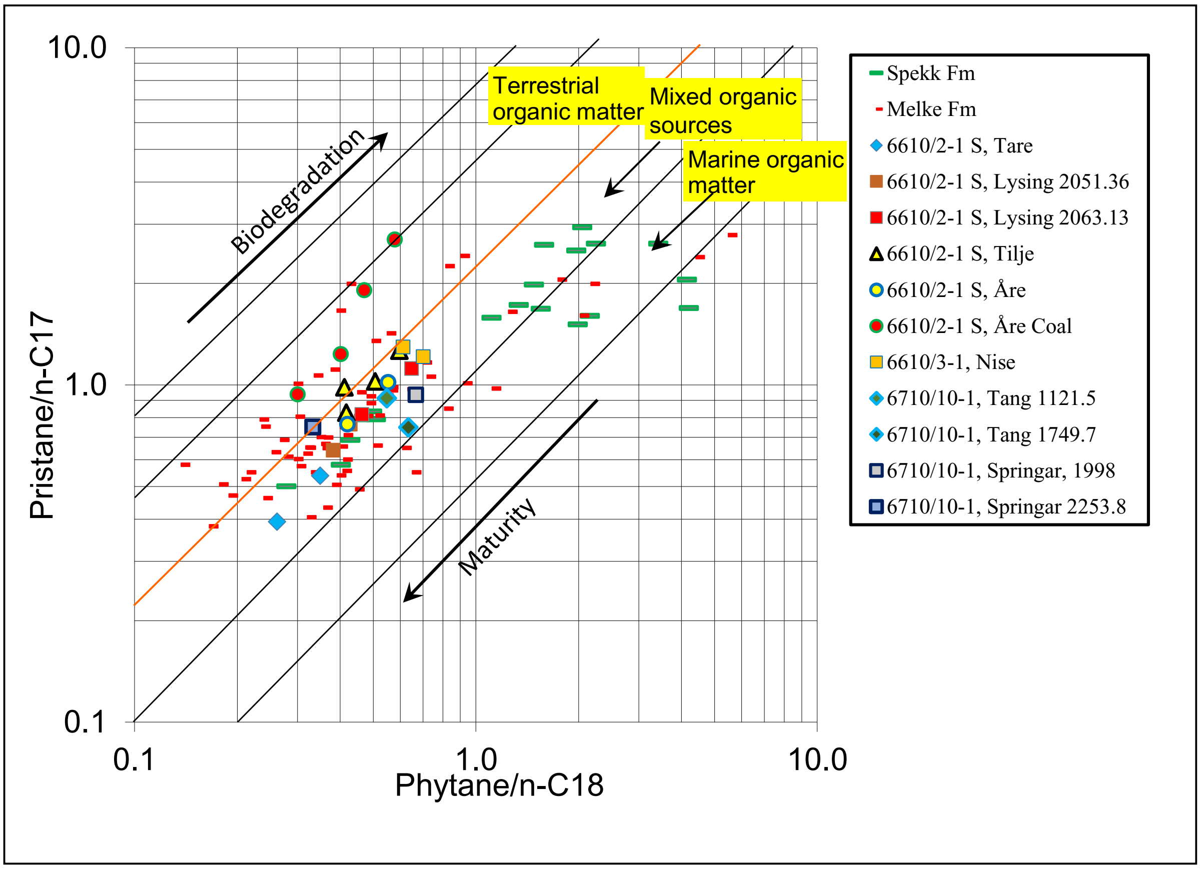


Fig. 3.13 Source rock characteristic Biomarkers
Spekk Formation is a marine to mixed organis source (oil prone), while Åre Formation is dominantly a terrestrial source (i.e.gas prone)

Charge contribution is also possible from Cretaceous SR intervals. However, these SR intervals are significantly leaner than the Jurassic intervals mentioned above. TOC rarely exceeds 1 wt%, and HI is in the low hundreds, indicative of primarily gas potential.

The Jurassic source rocks in the relevant wells for the petroleum system on Dønna Terrace and Nordland Ridge have rather low maturity and have not been exposed to very high temperature in the past, and the measured hydrogen index (HI) and total organic carbon (TOC) represent probably close to initial values, . Tabulated average TOC and HI for the source rocks are listed in Table 3.2.

Table 3.3 Measured HI and TOC in Jurassic Source Rocks.

Formation	**TOC Measured**	**HI Measured**	**Number samples**
Spekk	8.8	325	17
Melke	2.3	150	56
Åre	30	210	88

The thickness of the Spekk Fm is 80m in Well 6610/3-1 R. This well is located within the mature source rock area for the prospects, and is expected to be representative for the SR thickness in the basin. The Melke Formation source rock is estimated to about 100 m in this area. For simplicity the thickness for net source rock potential in Åre Fm is set to 15 m.

Maturity

Due to the Pliocene/Quaternary sedimentation the temperature is at maximum at present day in the main source rock areas. Temperatures from drill stem tests (DST) are recognized to be most reliable, and are plotted against depth below seabed for relevant wells near the drainage area for the prospects, (Fig. 3.14).

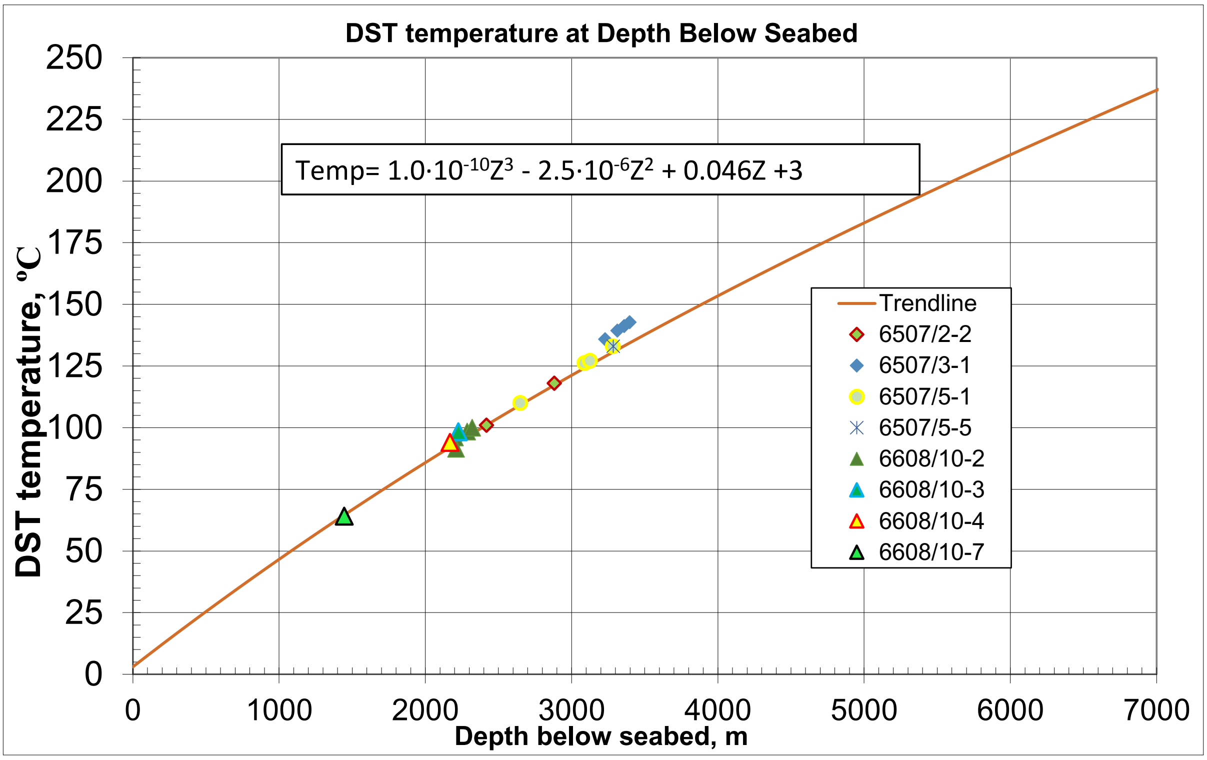


Fig. 3.14 DST Temperature at Depth below Seabed

The temperature trendline, together with the burial history, were used to predict the temperature history. The input to the burial history modelling consisted of seven depth maps as shown in Table 3.3.

Table 3.4 Depth Maps used in Basin Modelling.

Interpreted horizons	Age (mybp)
Seabed	0
Kai Fm	4
Top Brygge	34
Base Tertiary	65.5
Base Cretaceous Unconformity	142
Top Melke Fm (BCU+100m)	161
Near Top Åre (coal marker)	189

The maturity parameter Vitrinite Reflectance (VR) has been examined in wells in the area to establish the level of maturity of the source rocks, and then compared to the modelled maturity for calibration of the thermal history. The data indicates no major erosion and uplift in the area (Fig. 3.15). The modelled transformation ratio of the kerogen to petroleum at BCU/Top Spekk Formation level, shows that the transformation ratio of 0.2, which is near start expulsion of petroleum, is reached at about 2850 m MSL. This is about the as for the VR data, which increase the level of confidence in the thermal history model. Cumulative oil and gas expelled from the SR intervals for the Blekksprut Prospect is shown in Fig. 3.16. Similarly the cumulative oil and gas expelled from the three Jurassic SR intervals in the drainage area for the Triassic leads is shown in Fig. 3.17.

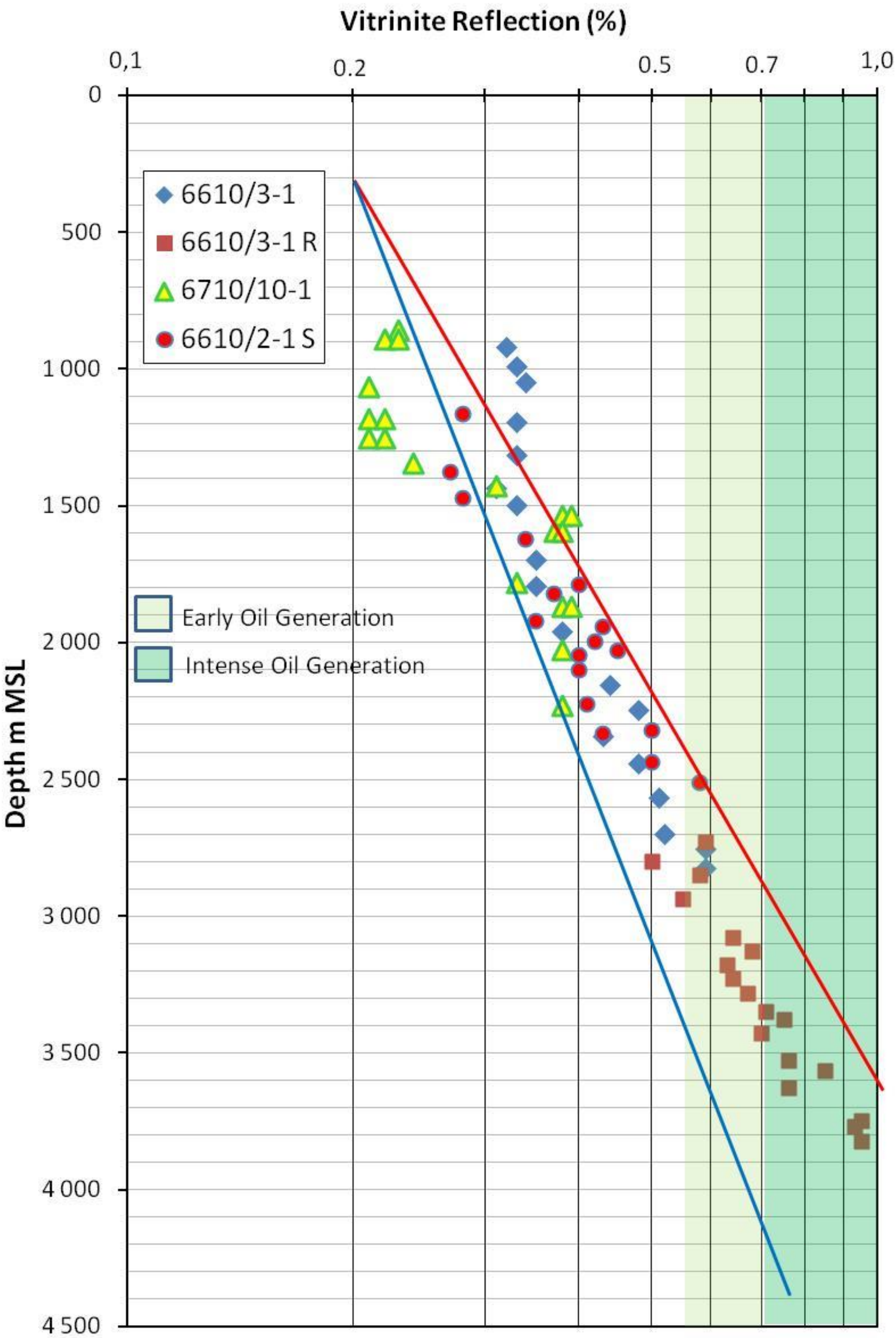


Fig. 3.15 Vitrinite Reflectance versus Depth

For kerogen deposited as marine siliclastics, sediments will start expulsion at about 0,55-0.6% Ro, which in this area is at about 2900m-3000m MSL. Immature samples have VR of 0.18 - 0.20 Ro. No sign of major erosion and uplift.

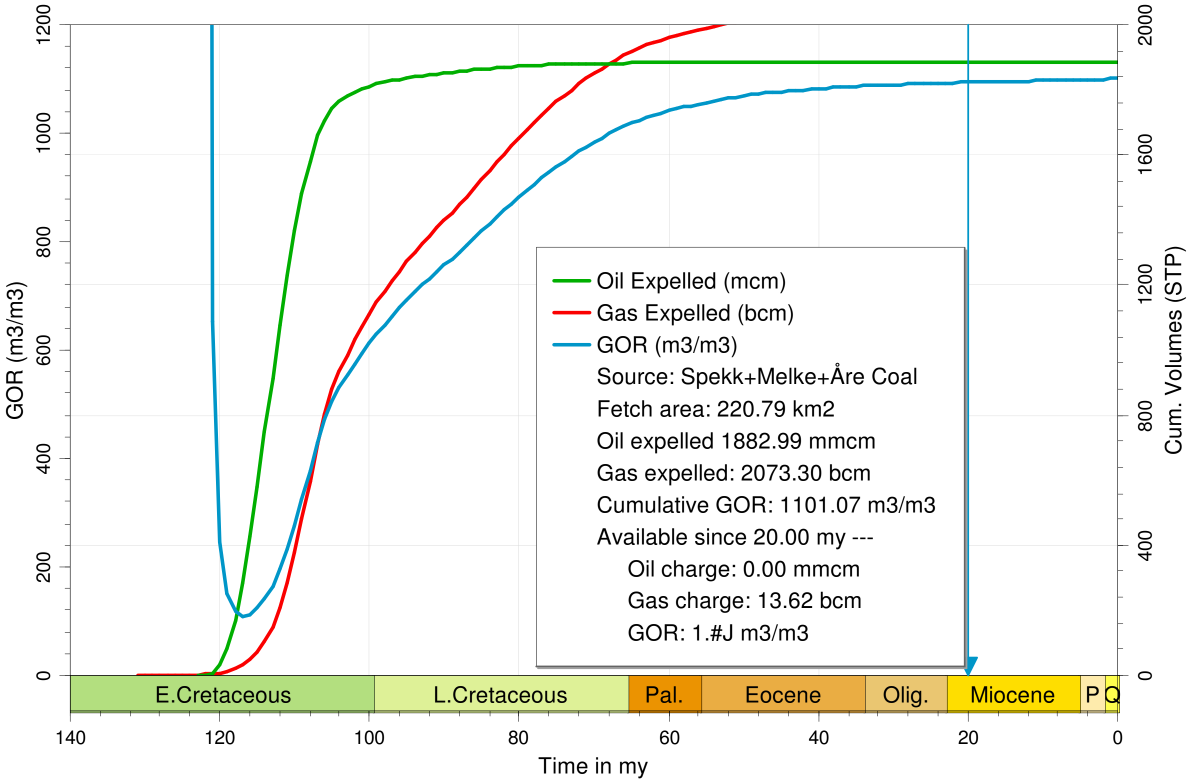


Fig. 3.16 Charge Volume History for Blekksprut Prospect

The cumulative charge volume history shows that in recent times gas is the dominant HC type available to the prospect

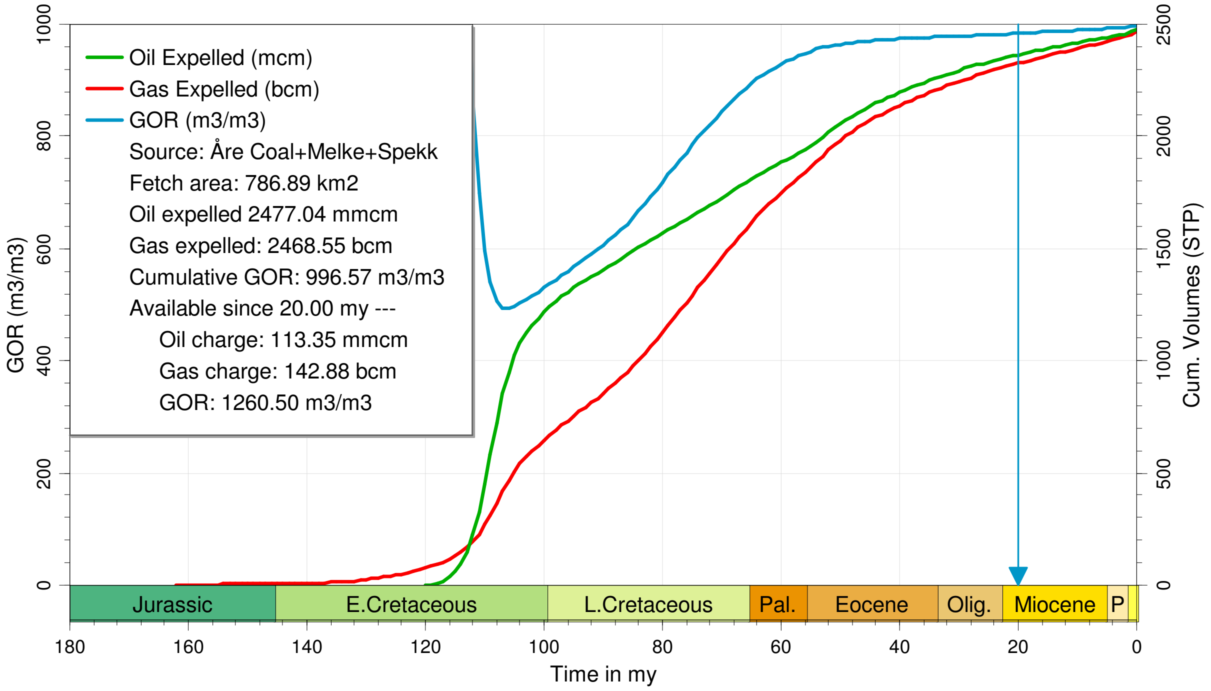


Fig. 3.17 Charge Volume History for Triassic Leads

Compared to Blekksprut the Triassic leads located at the platform edge has a higher likelyhood of being oil filled

Migration

The drainage areas for the prospects Blekksprut and the Triassic Prospects located at the edge og the Grønøy High Platform area are shown in Fig. 3.18 and Fig. 3.19. The modelled migration into the prospects/leads is shown in Fig. 3.20, Fig. 3.21 and Fig. 3.22.

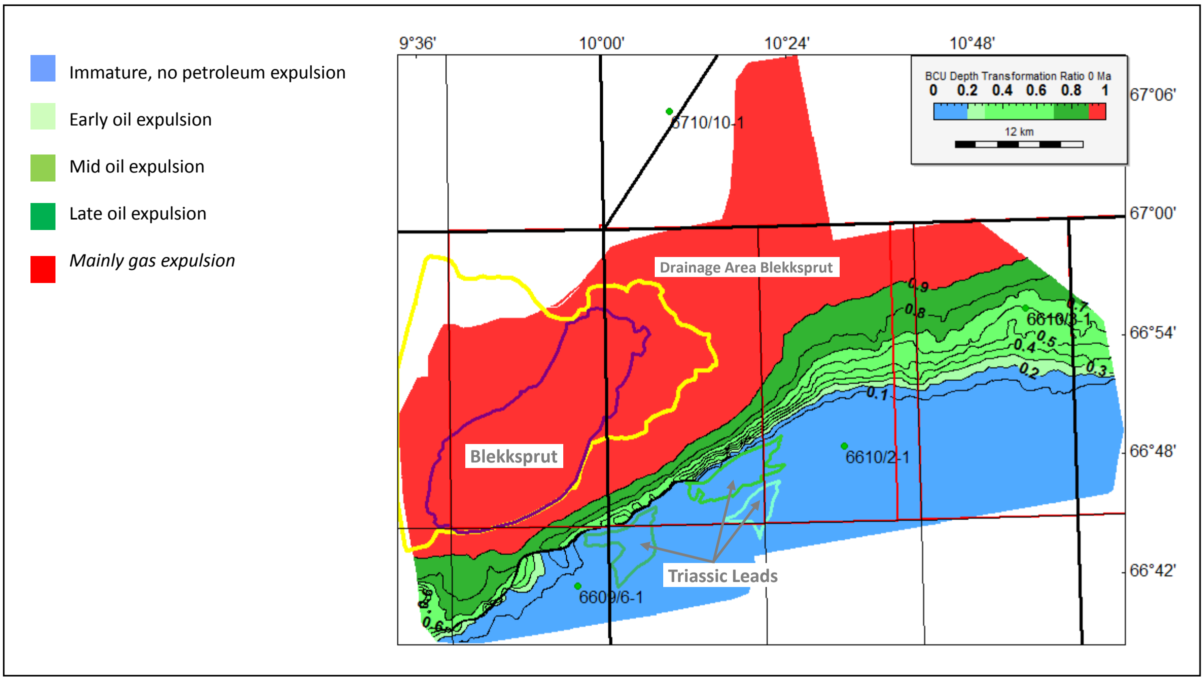


Fig. 3.18 Transformation of Kerogen to Petroleum at BCU level at present day

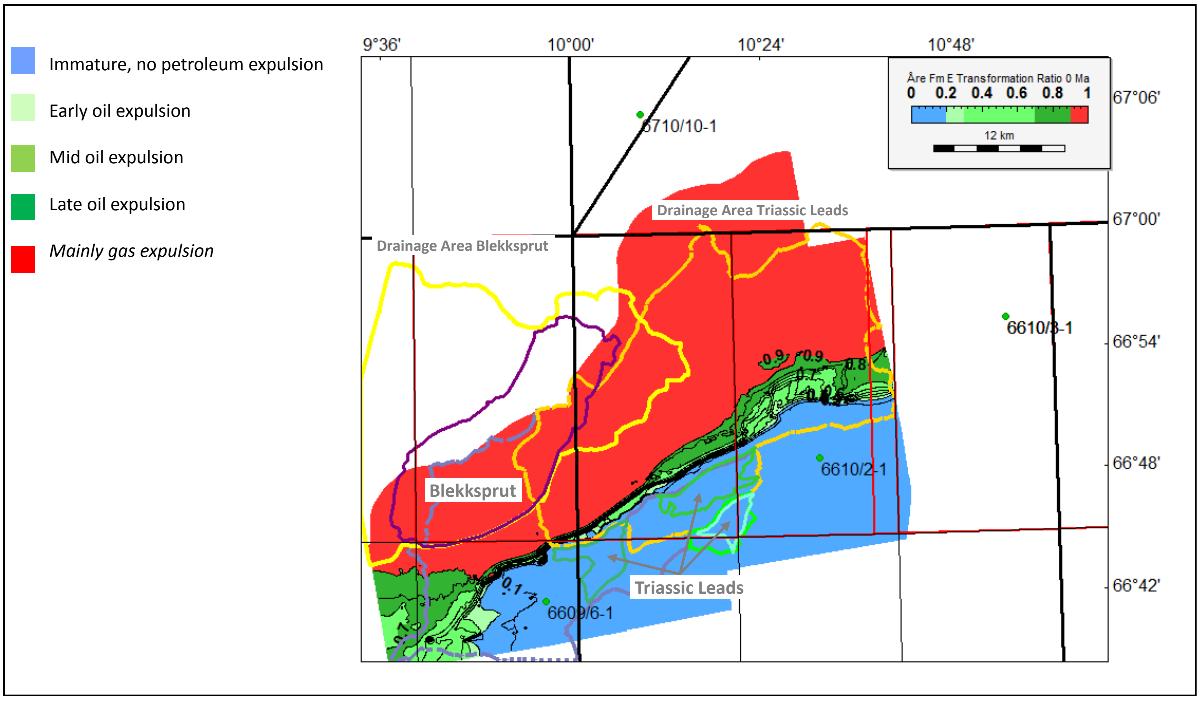


Fig. 3.19 Transformation of Kerogen to Petroleum at Åre Fm. level at present day

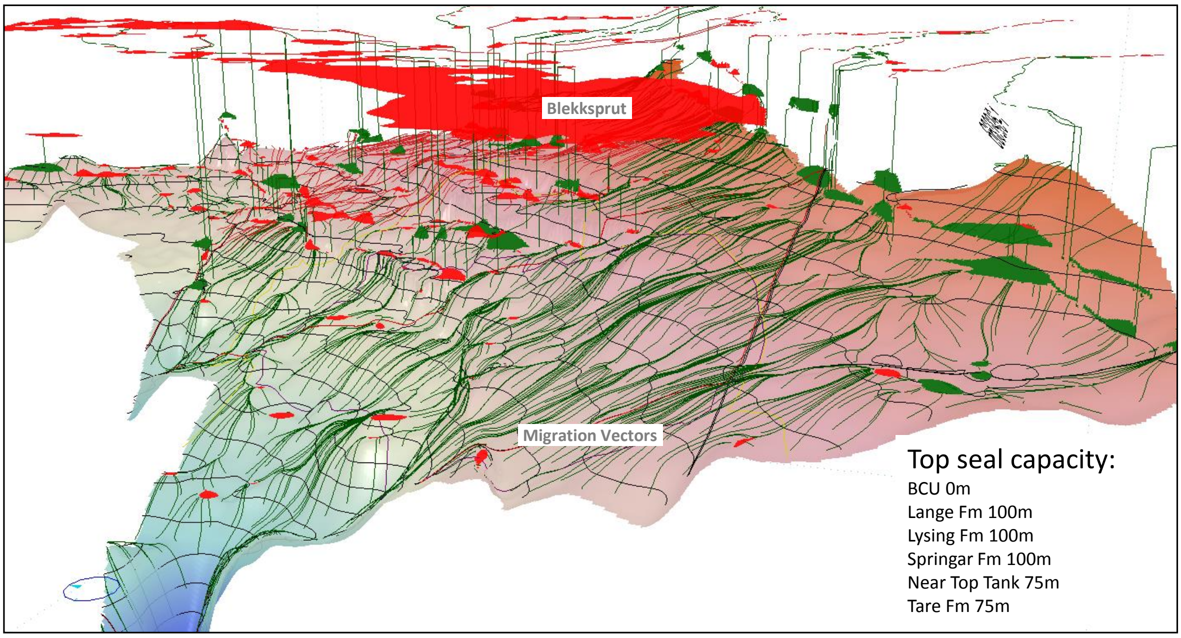


Fig. 3.20 Vertical and lateral Migration to Blekksprut Prospect

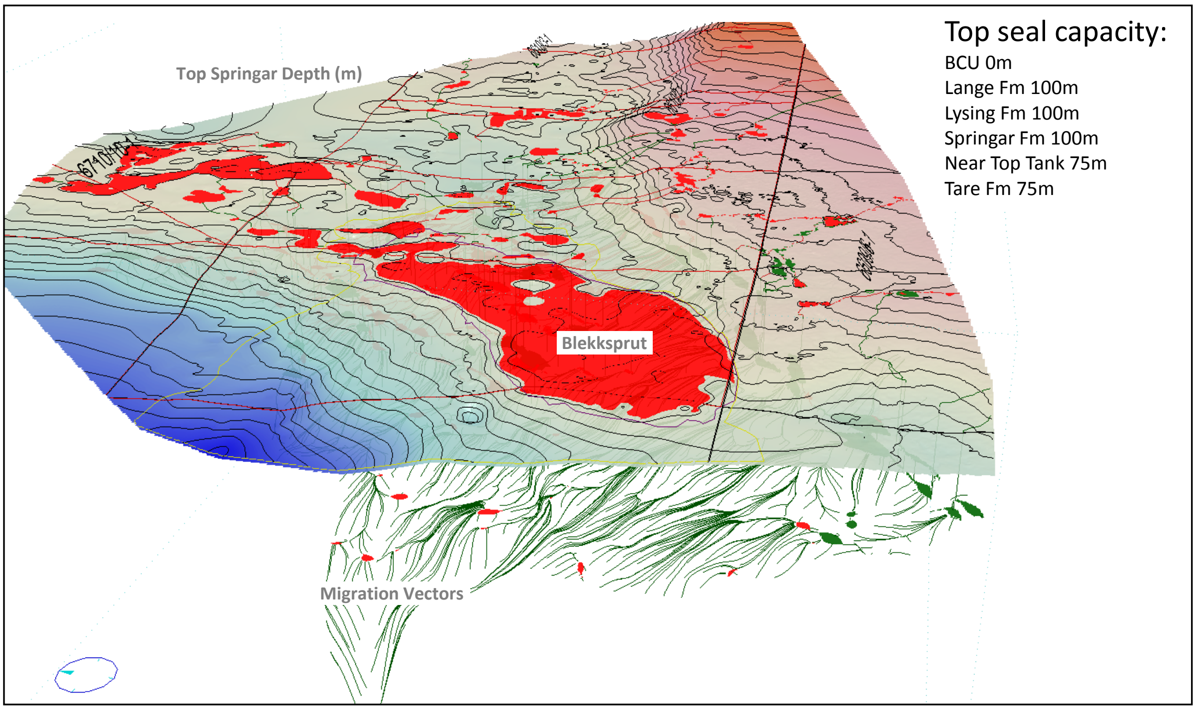


Fig. 3.21 Vertical and lateral Migration to Blekksprut Prospect (Tang/Springar)

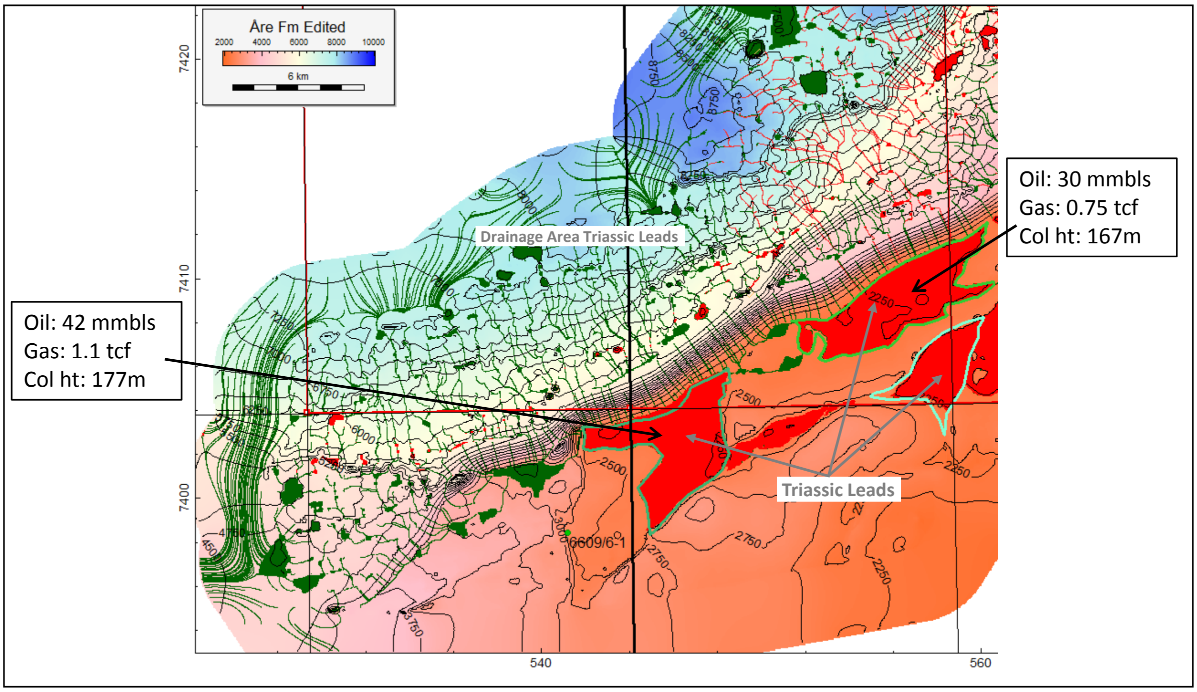


Fig. 3.22 Migration at Åre Fm. with all Faults open

The Prospect Blekksprut is dependent upon a vertical migration path from the Jurassic SR intervals, through a shale dominated Cretaceous section into the Tang main objective reservoir. In order to achieve that a connected permeability system needs to be present. The primary mechanism to achieve that are fractures, which could have been generated during the Miocene phase of doming. Additional avenues for vertical migration is expected to be hydrothermal venting of Late Paleogene age.

From Fig. 3.18and Fig. 3.19 it is observed that both Blekksprut and the Triassic leads are exposed to currently generating gas kitchens. That makes it likely that the prospects and leads will be gas filled, but the possibility also exists of differential top seal leakage of gas, in which case oil columns could be protected from leaving the traps. Overpressures have been recorded in the Cretaceous section in offset wells. The efficiency of vertical migration is expected to be hampered in areas with overpressured Cretaceous sands. In these areas, other convoluted migration routes are possible but invariantly associated with higher risk.

Wells drilled both south-west and south of the PL601 area display a potentially unfavorable pore pressure setting with regards to vertical fluid migration up in to the Paleogene sands. The Lysing and the Lange formations, startigraphically sandwiched between HC source and reservoir, regionally yield about 60 and 90 bar pore pressure above hydrostatic respectively, e.g. well 6609/5-1. It could therefore be assumed that hydrocarbons entering these Cretaceous sands will predominantly not be able to migrate vertically up in to the Paleogene age traps. However the Snøhetta well, 6609/6-1 encountered a much reduced level of overpressure (Nise 26 bar and Lange 19,5 bar), with pressures in Nise and Lange suggestive of vertical communication, thus possibly allowing for hydrocarbons to migrate up in to the Paleogene traps.

Another charge issue in the area is the timing of the main hydrocarbon expulsion pulse, which is modelled to take place in the Late Cretaceous, and the formation of the Tertiary traps, which took place significantly later, during the Miocene. In order for the early generated hydrocarbons not being lost to the prospects a process of slow migration through low permeability layers is one mechanism that could still make the hydrocarbons available to the Tertiary traps. Another mechanism is "hotelling", retention of the hydrocarbons in deeper traps, say of Cretaceous age, and later release of the hydrocarbons through doming and top seal breach (Fig. 3.23).

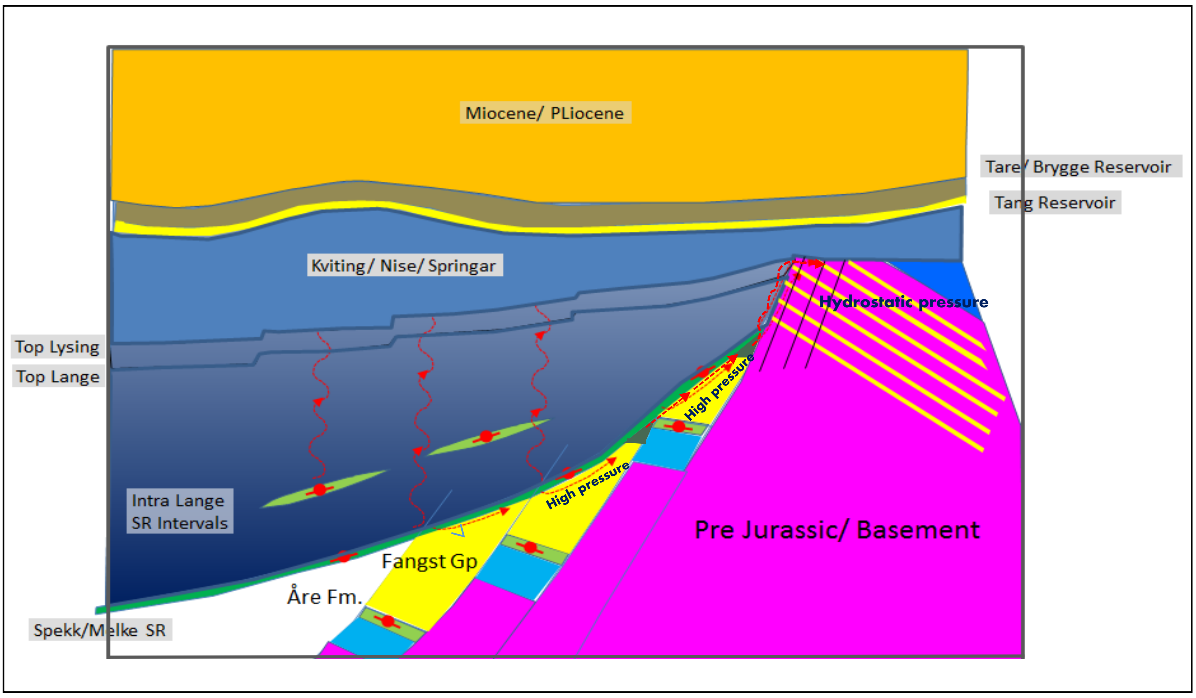


Fig. 3.23 PL 601 Conceptual Charge Cross Section
The cross section illustrates that both migration into Blekksprut and the Triassic leads, located at the Platform edge, requires a degree of tortuosity

Hydrocarbon Retention

In general, retention of hydrocarbons depends largely on the capillary entry pressures of the top seal lithologies. In the area of PL 601, burial is limited to 1000 - 1500 m (undercompacted), and consequently shales might still be porous thus limiting HC column heights. Pressure data indicate however, that shales (if present with the adequate lithofacies) would be able to sustain the oil columns expected in the mapped prospects (Fig. 3.24).

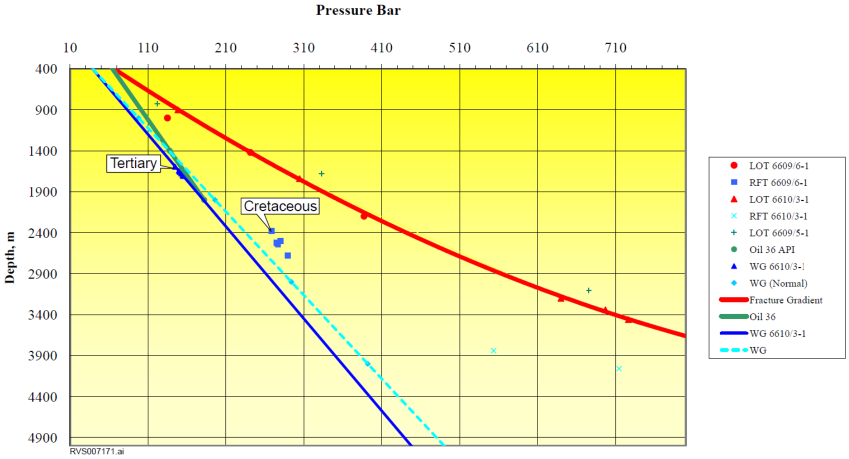


Fig. 3.24 Pressure Plot PL 601 Offset Wells
The plot illustrates that traps mapped at a depth of 1500m-2000m would be able to sustain hydrocarbon columns in excess of 500m , providing the reservoirs are close to hydrostatic pressure

3.4 Plays

Results of the PL601 offset wells are shown in Fig. 3.25. The identified plays in the license area are summarised in a cartoon drawing (Fig. 3.26). The cartoon has a notional horizontal and vertical scale to provide estimates of burial depth and size of fault blocks.

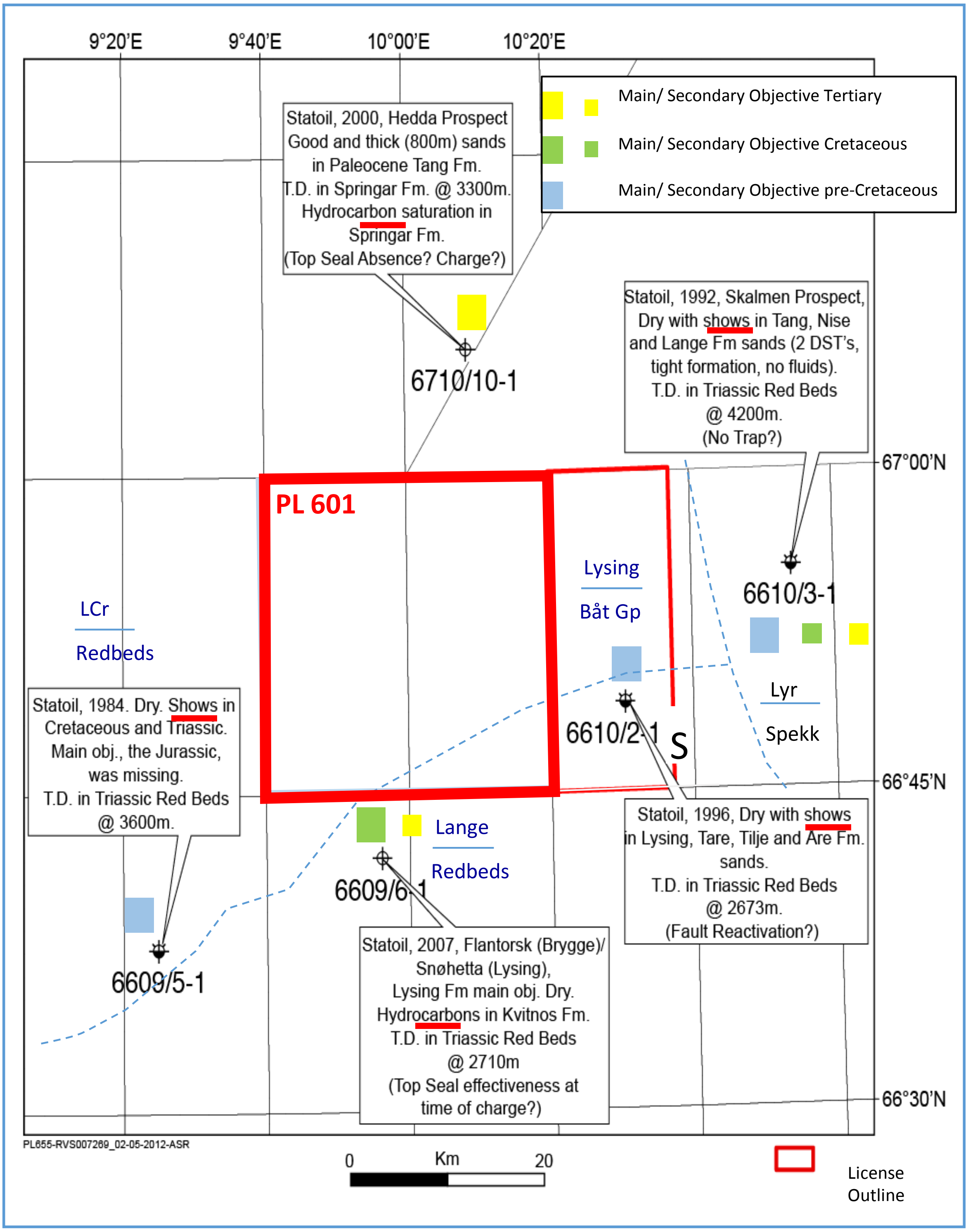
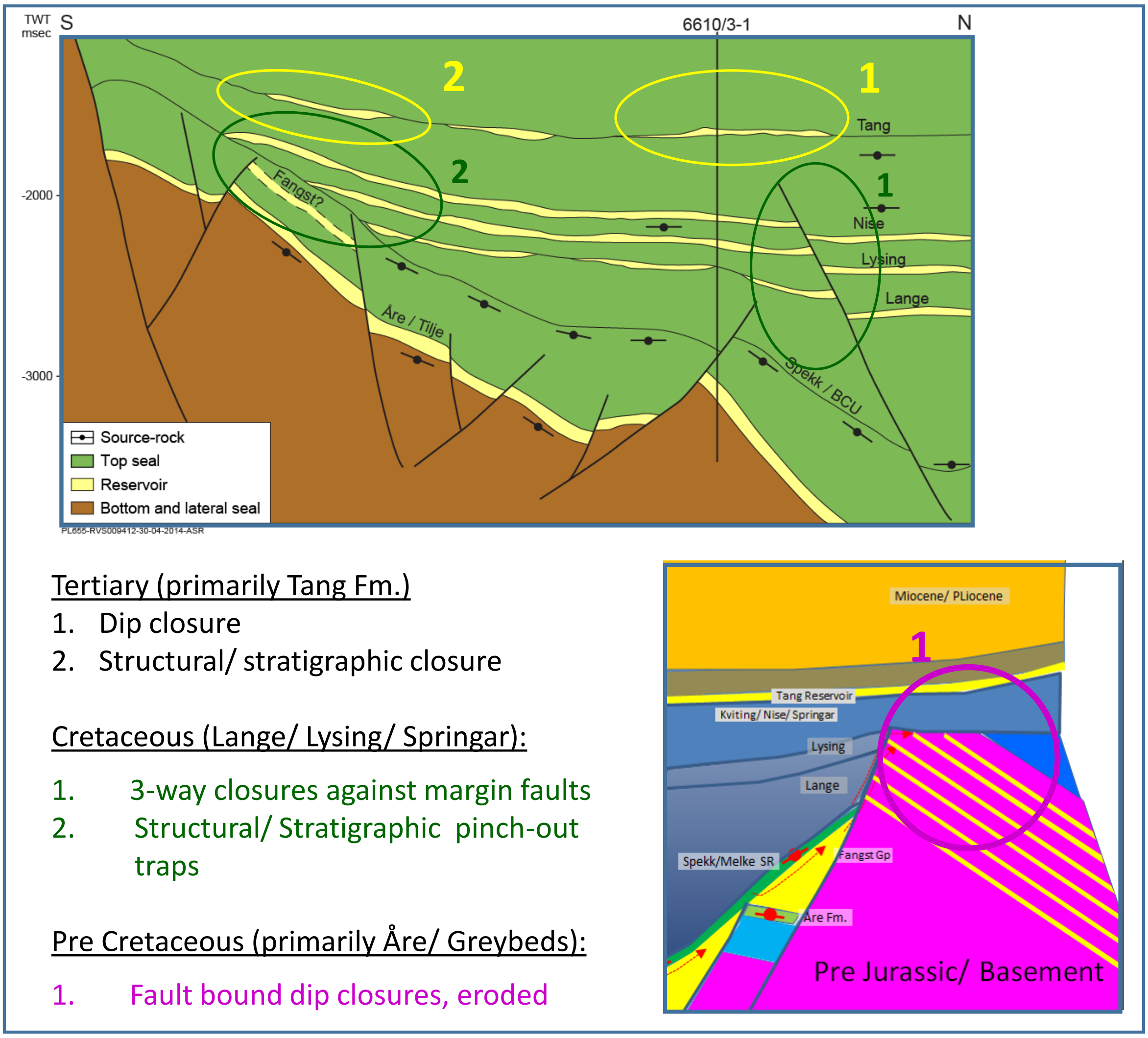


Fig. 3.25 PL 601 Area. Well Results

All PL 601 offset wells contained hydrocarbon shows (marked with red), but for various failure reasons they all encountered water bearing reservoirs



Tertiary (primarily Tang Fm.)
1. Dip closure
2. Structural/ stratigraphic closure

Cretaceous (Lange/ Lysing/ Springar):
1. 3-way closures against margin faults
2. Structural/ Stratigraphic pinch-out traps

Pre Cretaceous (primarily Åre/ Greybeds):
1. Fault bound dip closures, eroded

Fig. 3.26 PL601. Main Identified Plays

Primary Play:
Paleocene Tang, play 1 in Fig. 3.26

The main play in the PL 601 license area is the Paleocene Tang Play. Trap types identified in the PL 601 license area are structural dome shaped closures (Blekksprut and Nupen West as primary prospects) and stratigraphic traps (Nori as primary prospect). Reservoirs are turbiditic sands shed from the Lofoten High and Grønøy High areas. As mentioned in section 3.2 the sandstones reservoir quality is commonly medium to good although variable within the study area. The variability being dependent upon primary depositional facies and mineralogy. In-house CPI analyses of the five relevant wells in the area (e.g., Fig. 3.27, well 6710/10-1). indicate porosity of 18% to 26% (and associated permeability of tens to hundreds of mD) for the Tang Formation sandstones.

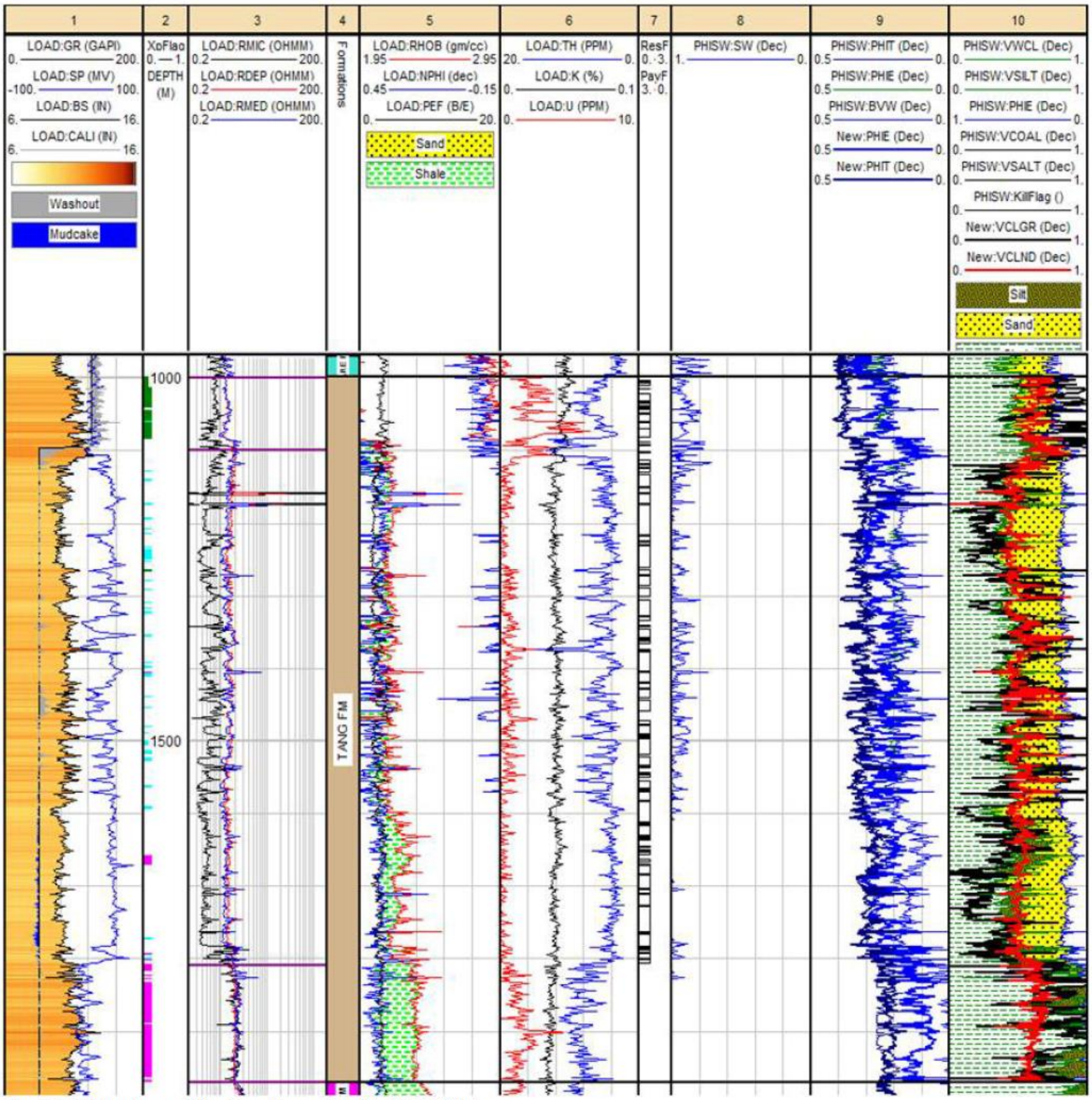


Fig. 3.5 CPI Analyses of the Tang Formation, Well 6710/10-1.

Fig. 3.27 CPI Analysis of the Tang Formation, Well 6710/10-1

As mentioned in section 3.2 the sandstones reservoir quality is commonly medium to good, although variable within the study area. The variability being dependent upon primary depositional facies and mineralogy. In-house CPI analyses of the five relevant wells in the area indicate porosity of 18% to 26% (and associated permeability of tens to hundreds of mD) can be expected for the Tang Formation sandstones. Depth of mapped prospects in Blocks 6609/3 and 6610/1 is 1500 - 2000 m. This would corresponds to porosities in the 16 - 30% range, with corresponding permeabilities of 100 mD plus (Lien et al., 2006) in the best depositional facies

Charge is provided from oil and gas generating Spekk Formation, with vertical migration paths through faults and fractures.

Secondary Plays:
<u>Cretaceous Springar and Lange sandstone play (Play 2).</u>

Lysing (and Lange) sandstones have been the target of some of the offset wells (e.g., 6609/6-1; 6610/3-1; 6609/5-1, Fig. 3.28), and they have been proven to consist of marine, mass-gravity flows. Sediment source area is likely in the south-west and west (Norwegian Mainland and/or Nordland Ridge/Rødøy High).

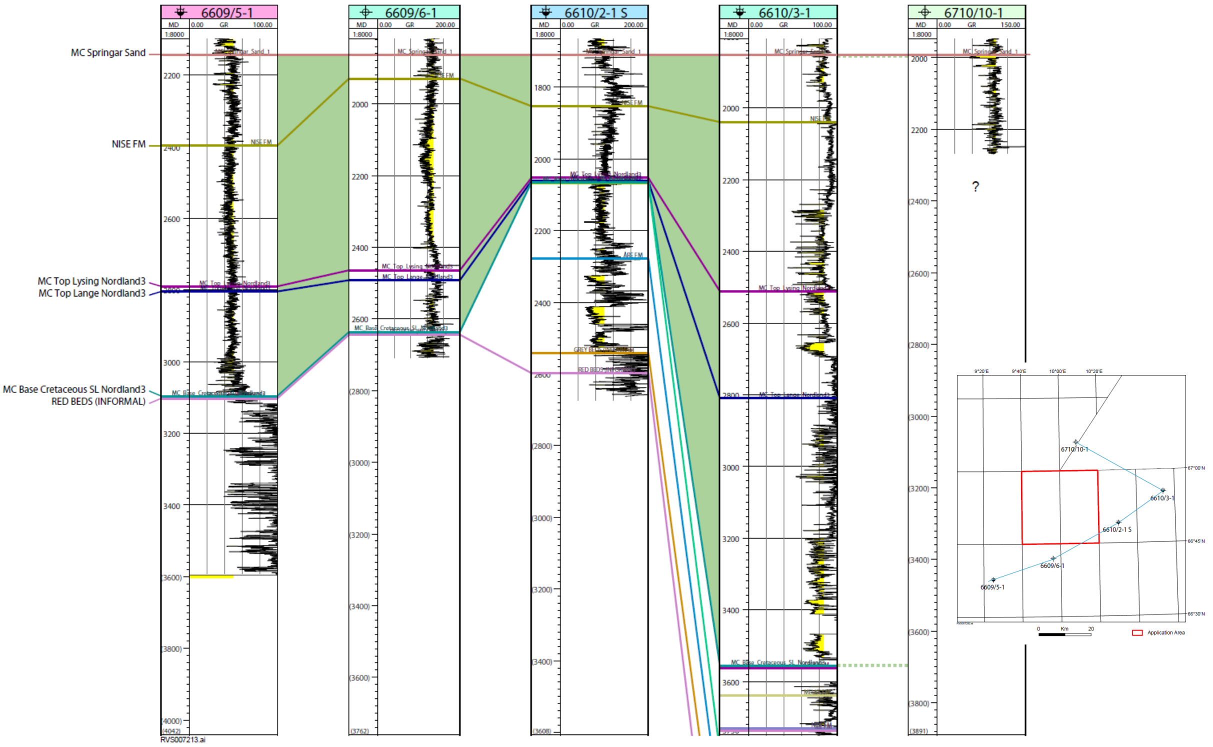


Fig. 3.28 Well Cross Section Cretaceous stratigraphic section

Their gross thickness is however limited and variable (e.g., between 10 and 40 m gross thickness and with low N/G's), as well as their reservoir properties (e.g., porosities between 8 and 20%, but with corresponding permeabilities of some of ten's of mD). In the PL601 area these units are buried deeper than in well 6610/6-1, expected at similar depths as in well 6610/3-1(R) (i. e., 2500 - 2700 m MSL). Therefore, similar or lower reservoir properties are expected in the PL601 area (depending upon primary depositional facies, mineralogy and charge). Trap mechanism would be of hanging-wall type, possibly in combination with a stratigraphic pinch out.

Lower Jurassic Båt and Triassic Play

The reservoirs for the prospects are the Lower Jurassic Åre Formation and the underlying Triassic age Grey Beds. Tilje Formation reservoir sandstones is a potential upside for the pre-Cretaceous prospects. Main Reservoir is expected to be the Åre Formation.

The thickest section of cored Åre Formation is found in well 6610/2-1S. The deposits are heterolithic, characterised by rooted claystones and pebbly, cross stratified clean sandstones. Palynological analysis of this well indicates a non-marine depositional setting. The sands are medium grained with well defined cross stratification, and with common nodules and/ or pebbles, and characterised by current ripple cross lamination with common fine carbonaceous debris.

The Åre Formation in well 6610/7-2 is composed of highly friable, fining upwards, fine to very fine grained sandstone. The coal layers seen on the cores are also recognised on logs by high GR reading and low density. The cored intervals in this well have been interpreted as a mixture of fluvial channels and lacustrine mud deposits. The facies elements have been interpreted to reflect a depositional environment with varying degree of tidal and marine influence. Porosity and permeability measurements from the cored section of offset wells, down to a depth of 2500m, results in the following averages:

Åre Formation. Porosity: 21,5%, Permeability 405 mD

Tilje Formation: Porosity: 24.4% Permeability 952 mD

The Greybeds are Ladinian-Rhaetian in age. The thickest penetration of the Triassic section is again found in well 6610/7-2. The cored section in well 6610/7-2 consist of grey-green, poorly to well sorted, fine to coarse grained, cross-stratified, clean sandstones, and have been interpreted as fluvial channel deposits. Sandstones are locally pebbly with siltstone and sandstone clasts.

The Tilje Formation has been interpreted as tidal sands/channels with fining upward successions representing tidally influenced distributary channel sediments. Highly bioturbated intervals, interpreted to be wave influenced shoreface deposits, can also be seen in the Tilje Formation.

The Lower Jurassic Båt and Triassic Play is considered to have a moderate potential in PL 601. The identified fault bounded closures are too small in size to be viable as drilling targets.

4 Prospect Evaluation

4.1 Prospect Mapping

As part of the work commitment in PL 601 the available seismic 3D data sets were reprocessed and merged in 2012. It turned out that the dataset was not of sufficient quality to bring any of the prospects in the license to drill-stage. It was therefore decided to carry out another attempt to extract more information from the available seismic data set, via reprocessing of a limited swath strip, oriented NW-SE, and containing well 6609/6-1 (Fig. 4.1). This work was carried out by CGG over a 7 month period. The final result was encouraging with respect to data quality. Specifically the imaged section at Springar level brought out details that shed new light on reservoir/ seal pairs at this level. The conclusion was that the mapped Springar level can not be used to represent a Tang (Egga Fm.) closure in Blekksprut, and, furthermore, that the reservoir sequences around the Springar level (Springar and Lower Tang) does not have a reliable top seal.

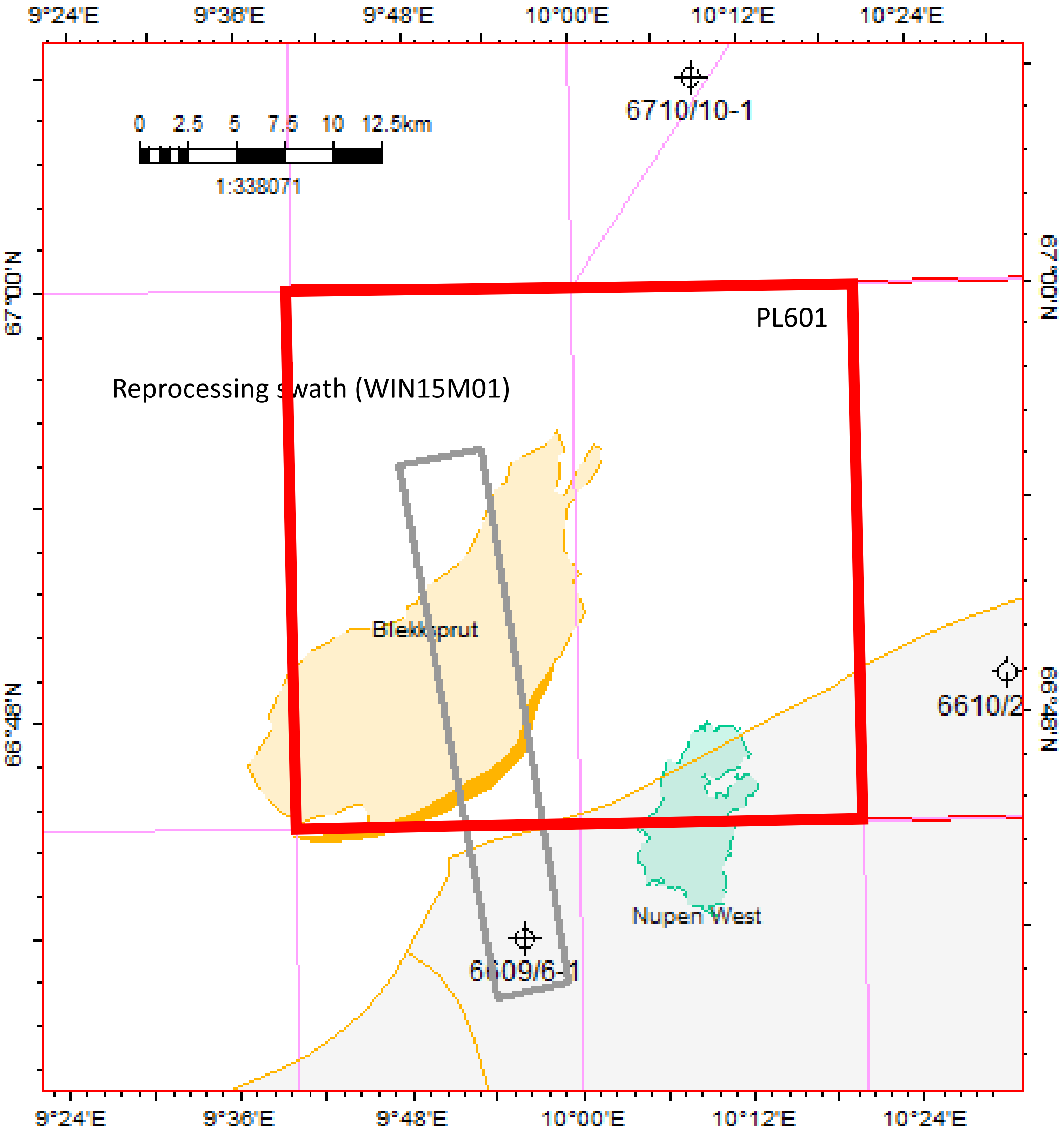


Fig. 4.1 PL 601 Location Swath Re-processed Volume

The swath outline highlights the fully migrated volume

Below is a short description of the three highest ranked prospects in PL 601, followed in the next sub-chapters of the latest volumetrics estimates and prospect risking.

Nori

Nori is mapped as a stratigraphic trap on the southern flank of the 6710/10-1 high. This is a prospect brought into the PL 601 license group by Rocksource (now called Pure Energy), that has both Tare and Tang (Paleocene) reservoir objectives. The trap concept is pinch-out of onlapping Tang and Tare sandbodies against the high.

Several events in the Paleocene package, from Top Springar at the base to Top Tare, deemed mappable across the southern flank of the 6710/10-1 high, were interpreted. The purpose was to look for geometries in the up-dip direction that could be seen as a true updip sand pinch-out/ permeability barrier. Expressions of amplitude change coinciding with depth contours was another criteria which was also looked into.

In addition an AVO screening exercise was done to look for support for support for hydrocarbon presence. Confidence in the viability of a hydrocarbon filled trap would be sought via a positive combination of these criteria. Well to Seismic tie is illustrated on Figures (Fig. 4.2, Fig. 4.3). Shale/ sand contact has been modelled to be soft generally, but as can be seen from (Fig. 4.4). the events mapped are likely combined responses, due to individual sand/ shale thickness variation.

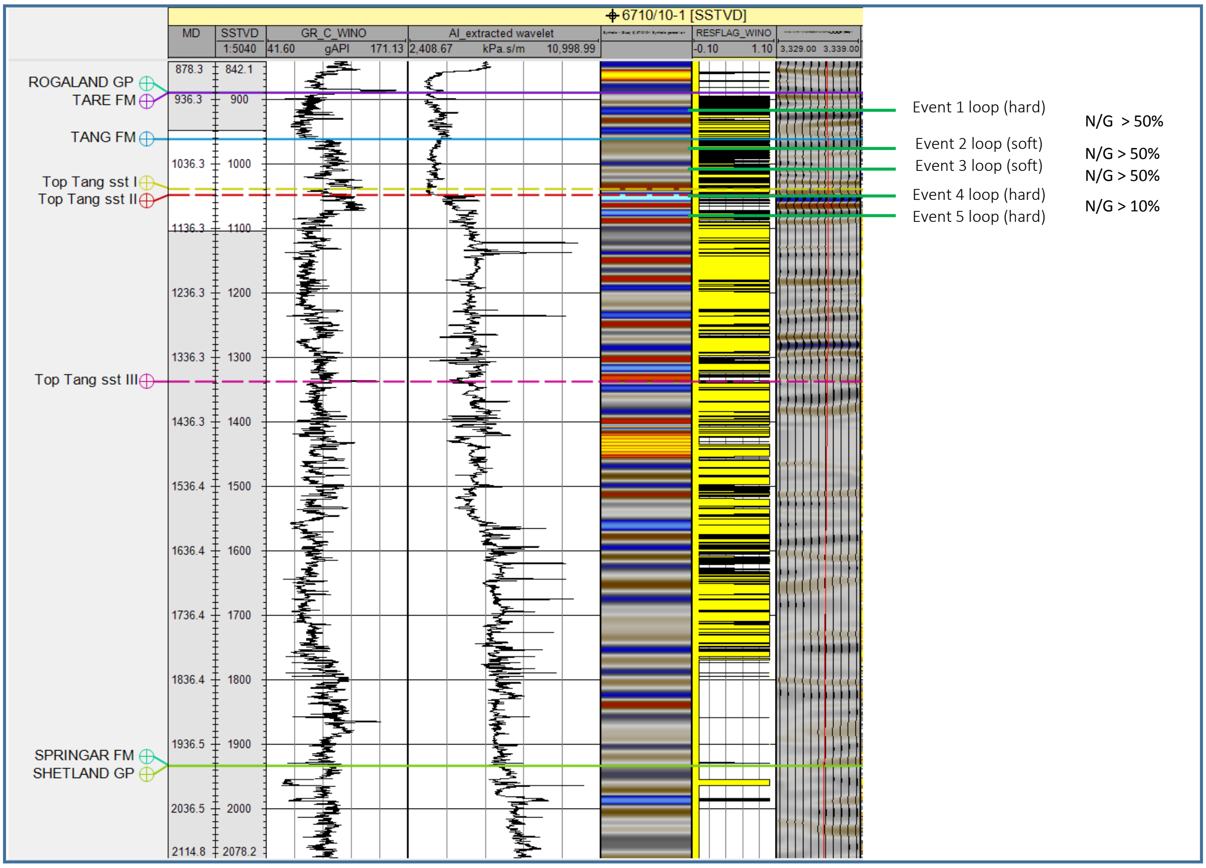


Fig. 4.2 Well 6710/10-1 Seismic to Well Tie Eocene/ Paleocene

Sand (yellow) and shales (black) from CPI log. Interpreted Eocene (Tare) and Paleocene (Tang) markers are annotated. Notice the lack of sands in the deeper part of the well section

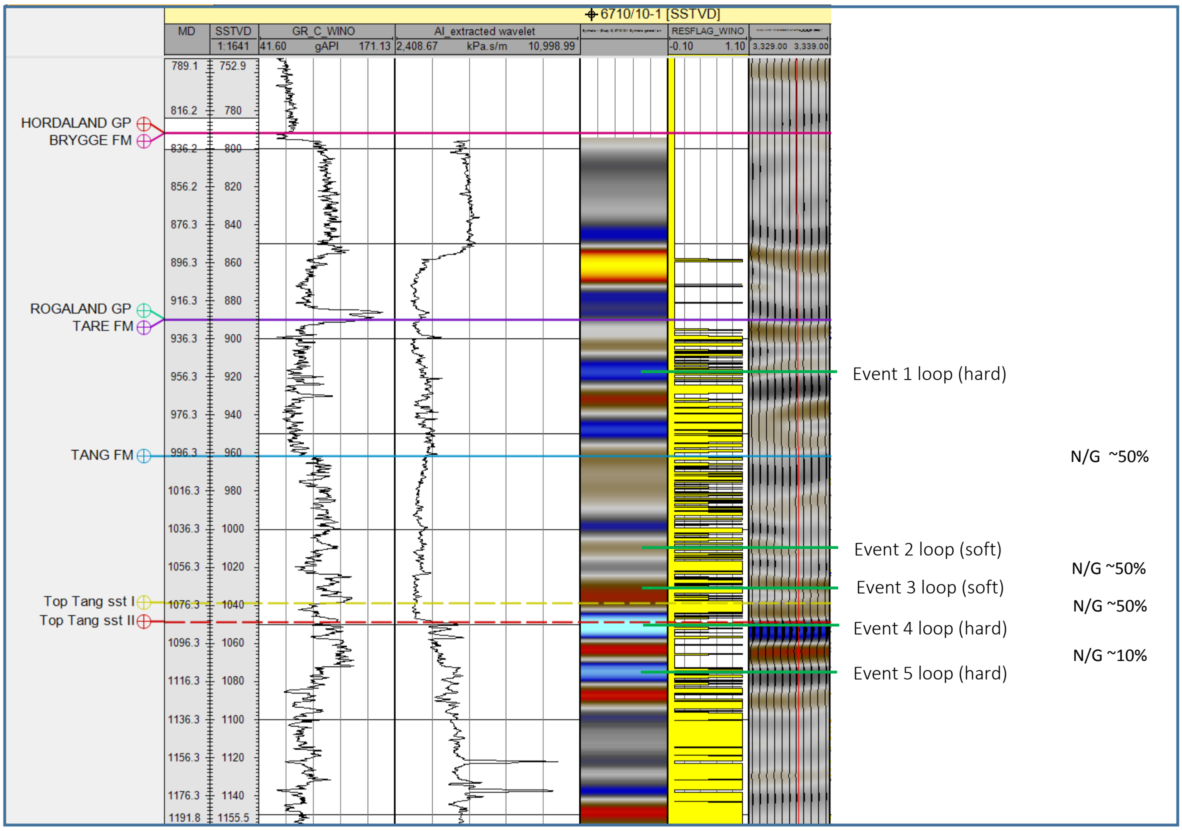


Fig. 4.3 Well 6710/10-1 Eocene/ Paleocene Seismic to Well Tie Detail

Details from log in Figure 4.2

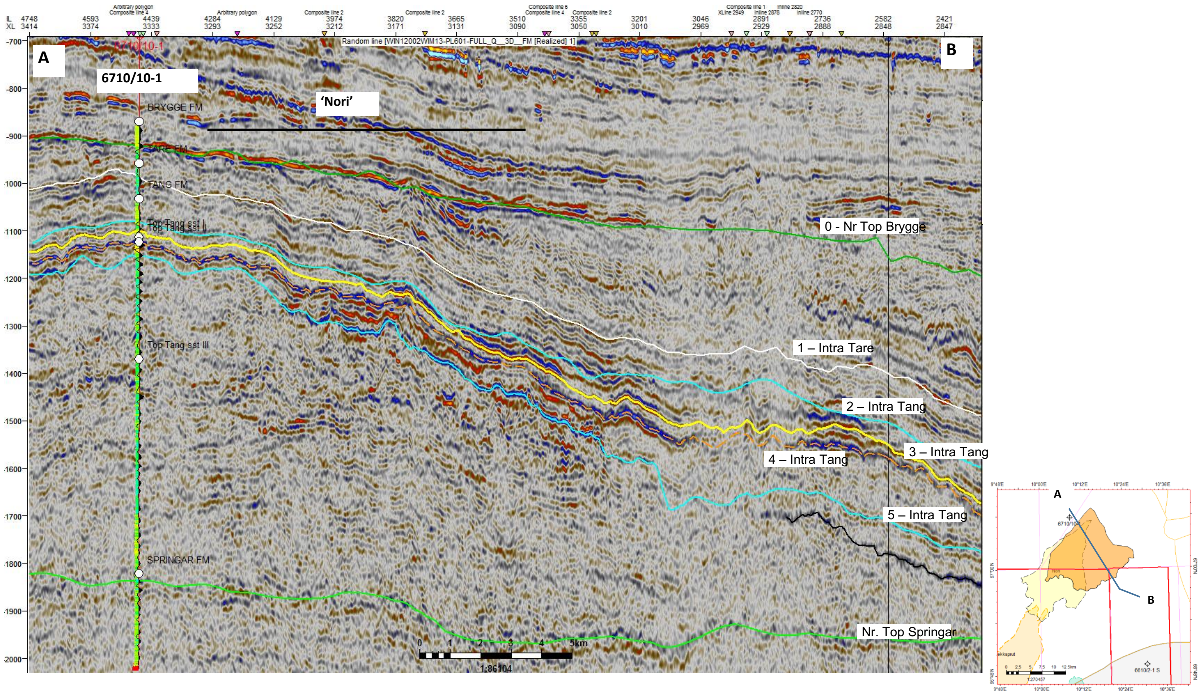


Fig. 4.4 PL 601 Arbitrary Seismic Transect

The annotated markers are assumed associated with condensed (highstand) shales. For the Nori prospect the upper two intervals (1-2 and 2-3), and a deeper interval (4-5) has been chosen for prospect assessment

a. Event mapping

Eight Tertiary events were mapped, as shown in Fig. 4.4, from the deepest marker, Top Springar to the youngest Near Top Brygge. All the three highest ranked prospects were evaluated based on these marker interpretations. For the Nori prospect all the Paleocene events were used in the prospect mapping work. Although the data is of moderate to good quality, event continuity is in places poor. Interpretation in these areas become more conjectural. Generally the event packages are thinning in an up-dip direction (Fig. 4.4.)

b. Trap Expression

Since none of the interpreted events show 3-way dip-closure towards the dry well 6710/10-1, expressions of sand pinch-out becomes critical in defining a Nori trap. Abruptness of the updip interval thinning, in combination with interval convergence and changing RMS expression are all positive criteria for sand pinch-out. Another possible updip permeability barrier are faults. Thief sand decapitation in an up-dip direction must be demonstrated to be present using these simple criteria, as illustrated in the sketch in Fig. 4.5

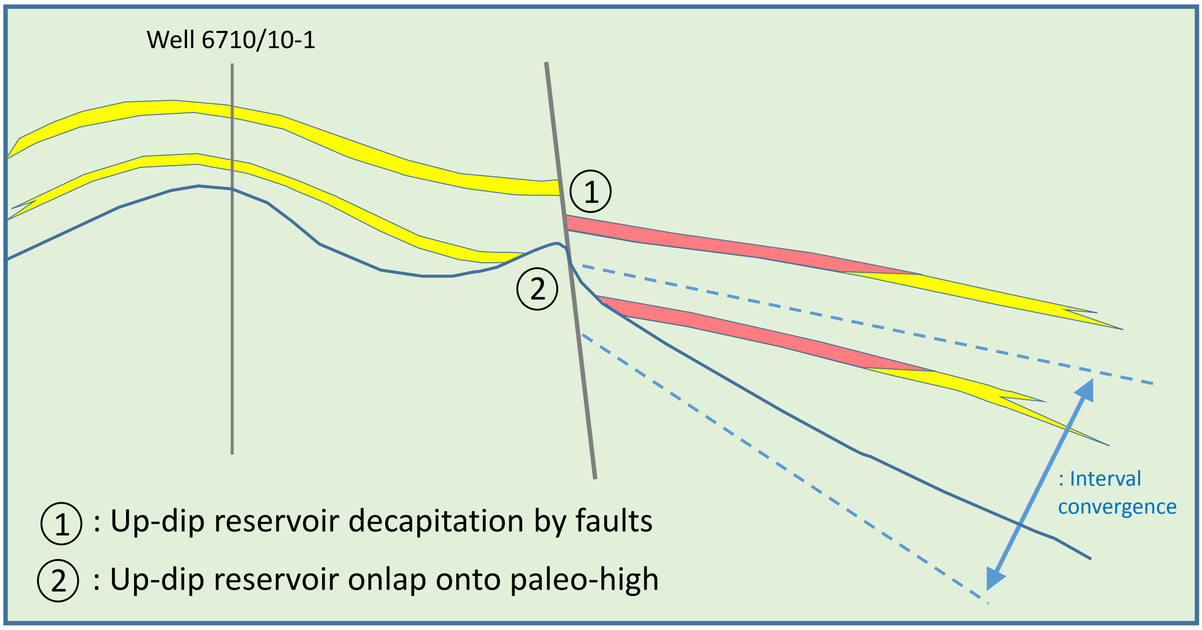


Fig. 4.5 Nori. Possible Updip Trap Mechanisms

As no convincing "high" (2) can be observed on seismic the most likely mechanism for sealing off a sand body in an up-dip direction is faulting (1).

The intervals examined for trap presence are 1-2, 2-3 (close to Rocksource's outline of Nori strat trap) and 5-4, which is the interval with strongest amplitude expression. Figures showing combined RMS amplitude expressions and isochore maps of these 3 intervals are shown in: Interval 1-2: Figures Fig. 4.6 and Fig. 4.7. Interval 2-3: Fig. 4.8, Fig. 4.9, and Interval 4-5: Fig. 4.10, Fig. 4.11.

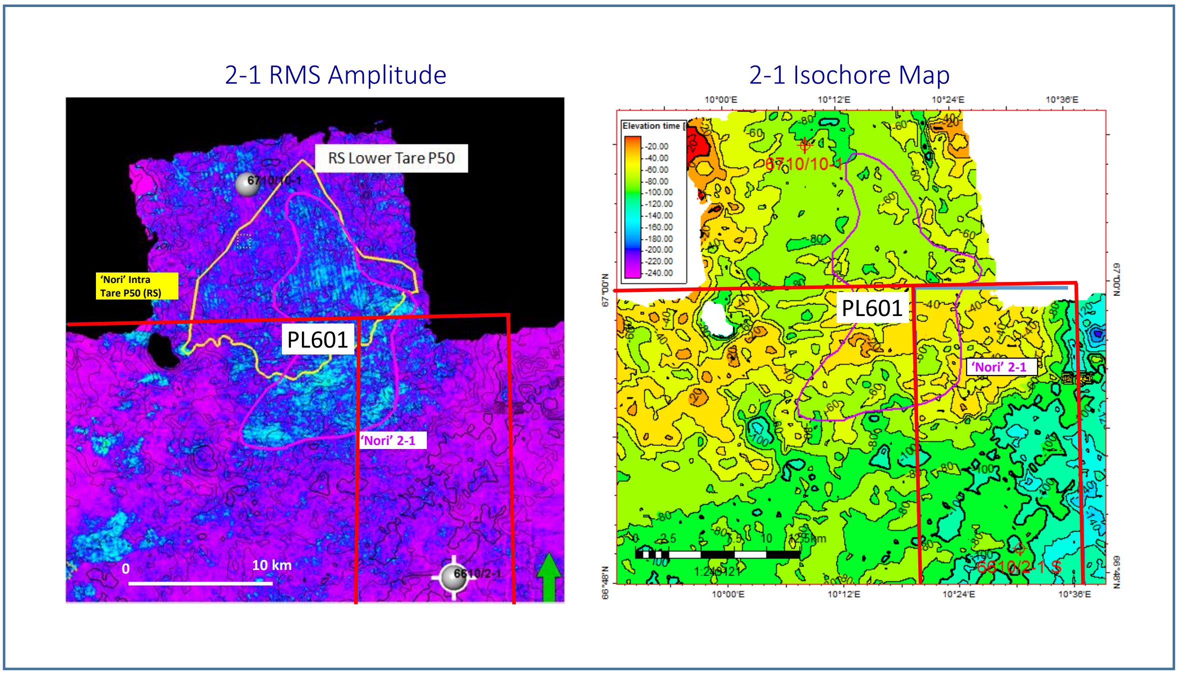
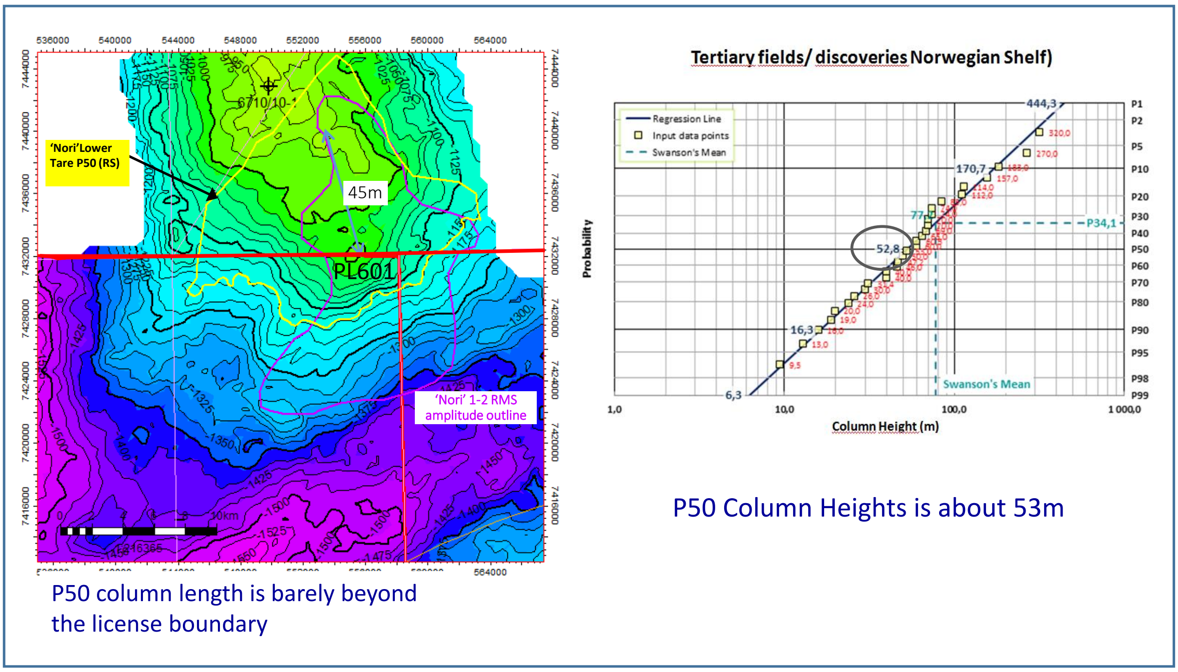


Fig. 4.6 Nori 2-1, RMS Amplitudes and Isochore Maps

There is apparent poor amplitude disruption between well 6710/10-1 and the "2-1 body". Also the interval does not seem to thin towards the well

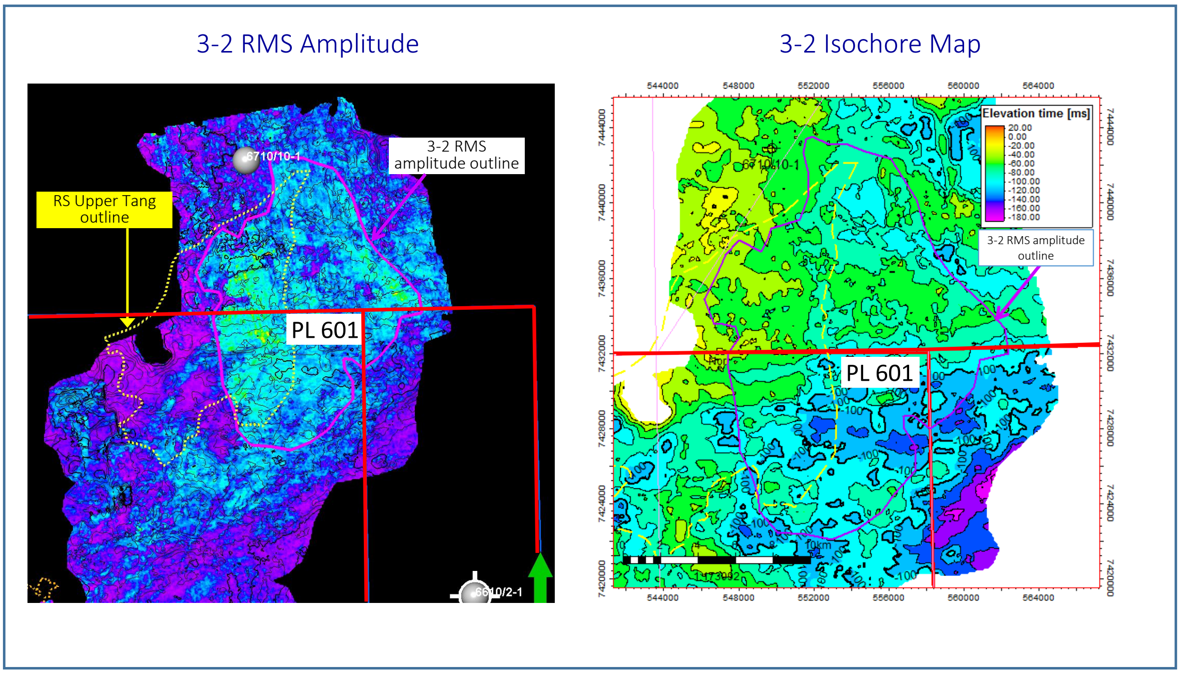


P50 column length is barely beyond the license boundary

P50 Column Heights is about 53m

Fig. 4.7 Top 1 Depth Map

The log-log plot to the right indicates a P50 column of about 53 meters (Mean 77m) for Norwegian Tertiary fields and discoveries. The down-dip column in PL 601 is therefore limited (circa 10m-30m)

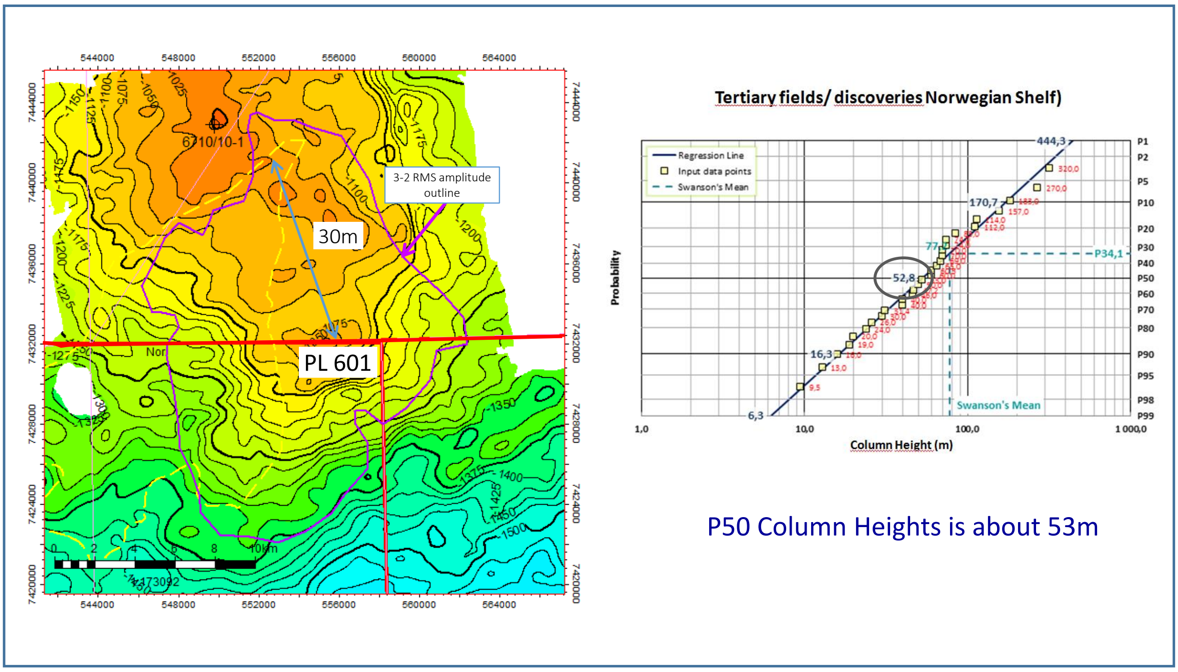


3-2 RMS Amplitude

3-2 Isochore Map

Fig. 4.8 Nori 2-3 RMS Amplitudes and Isochore Maps

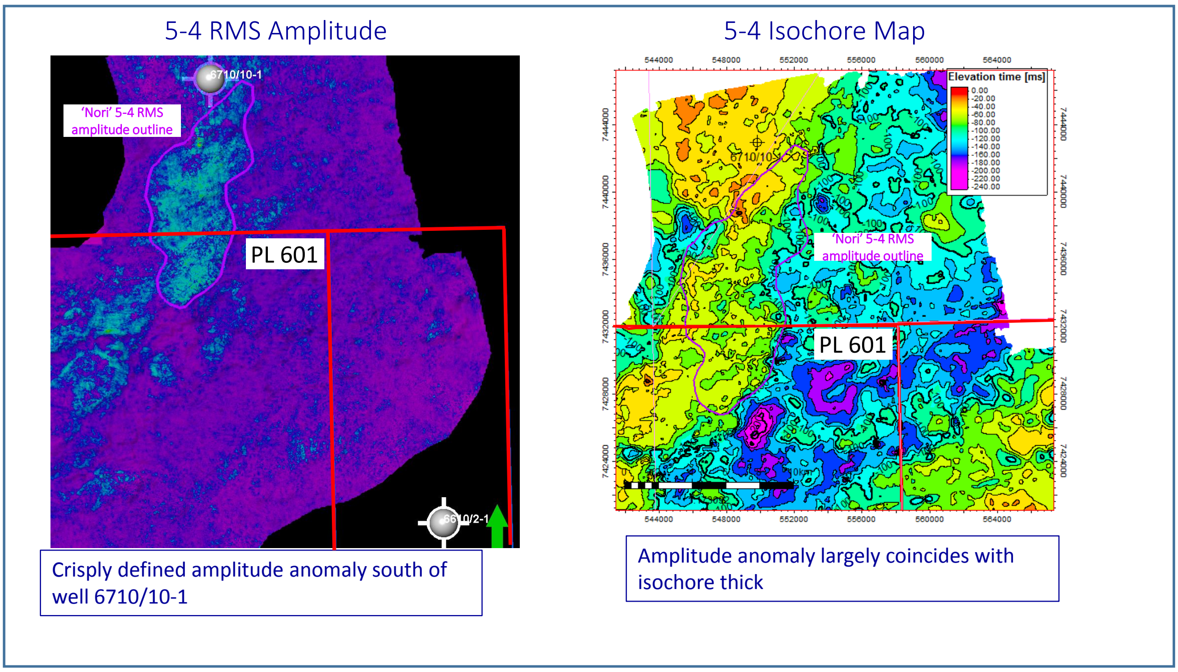
Moderate amplitude change between the well and the "3-2" body is observed. Some thinning from the interval towards the well can be seen



P50 Column Heights is about 53m

Fig. 4.9 Top 2 Depth Map

The column statistics (on the right side) allows for a down-dip column of 20m-40m in PL 601, resulting in moderate volumes

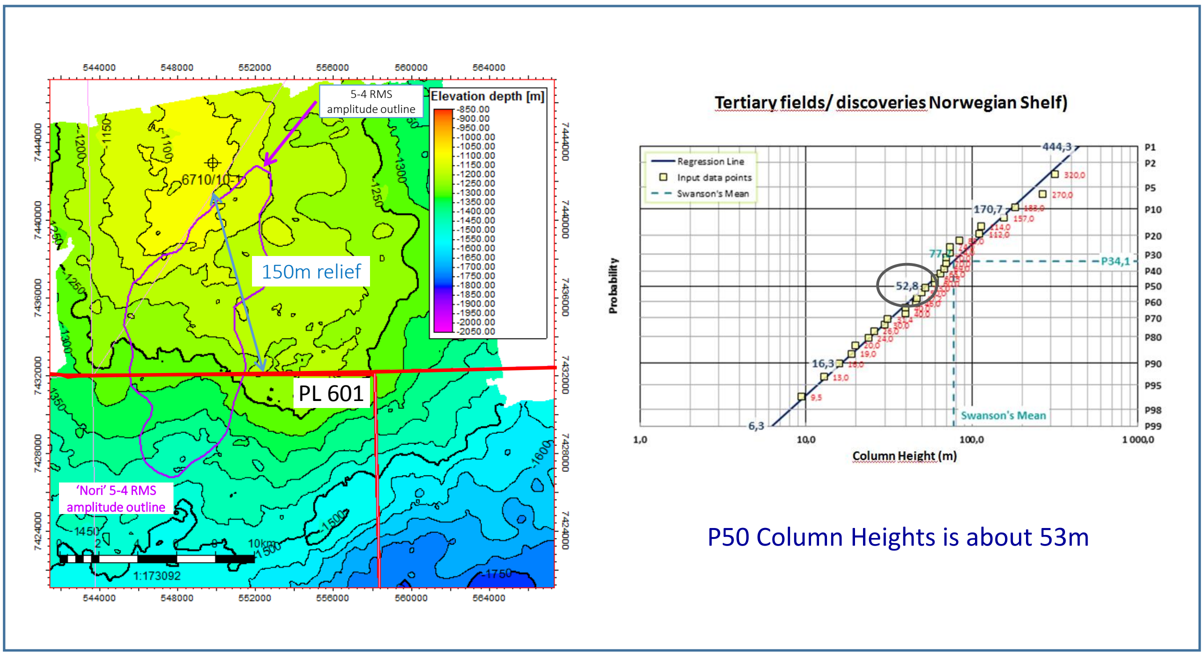


Crisply defined amplitude anomaly south of well 6710/10-1

Amplitude anomaly largely coincides with isochore thick

Fig. 4.10 Nori 5-4 RMS Amplitude and Isochore Maps

Poor amplitude change between the well and the "4-5" body, but the interval shows a well expressed amplitude anomaly. A clear interval thinning towards the well can also be seen



P50 Column Heights is about 53m

Fig. 4.11 Top 4 Depth Map

The column statistics (on the right side) indicates that a hydrocarbon column extension into the PL 601 license area is very unlikely

As all the intervals has a lack of down dip amplitude switch off statistics for column lengths for Tertialy fields/ discoveries on the Norwegian Shelf are applied. The column length distribution as provided by IHSE database results in P90 of 17m, P50 of 53m and P10 of 171m. The following qualitative assessment of the data extractions are summarised in Table 4.1 . In addition a Chaos extraction from a level close to top of the Tang sand package does not support presence of robust fault zone, likely to constitute an updip sand discontinuity (Fig. 4.12). The conclusion from the above qualitative exercise is that Nori carries high trap and seal risk. Primary representation of the Nori structure is the depth map at Near Top Tare (Level 1). At this level the crest of the trap is at about 975m. The P50 contact is at 1090m, and corresponds to a P50 volume of about 248mmbbls, which hardly straddles into PL 601 to the south of the crest. It is assumed that the HC- water contact distribution honours the column statistics for the Norwegian Tertiary fields, as highlighted in Fig. 4.9 and Fig. 4.11.

Table 4.1 Nori prospects trap Summary Observations

Interval	RMS expression of up-dip sand Pinch-out/ disruption	Interval Thinning	DHI amplitude expression	P50 Contact into PL601,using statistical contact
1-2	Weak	No	No	Barely
2-3	Weak	Yes	No	Barely
4-5	Yes	Yes	No	No

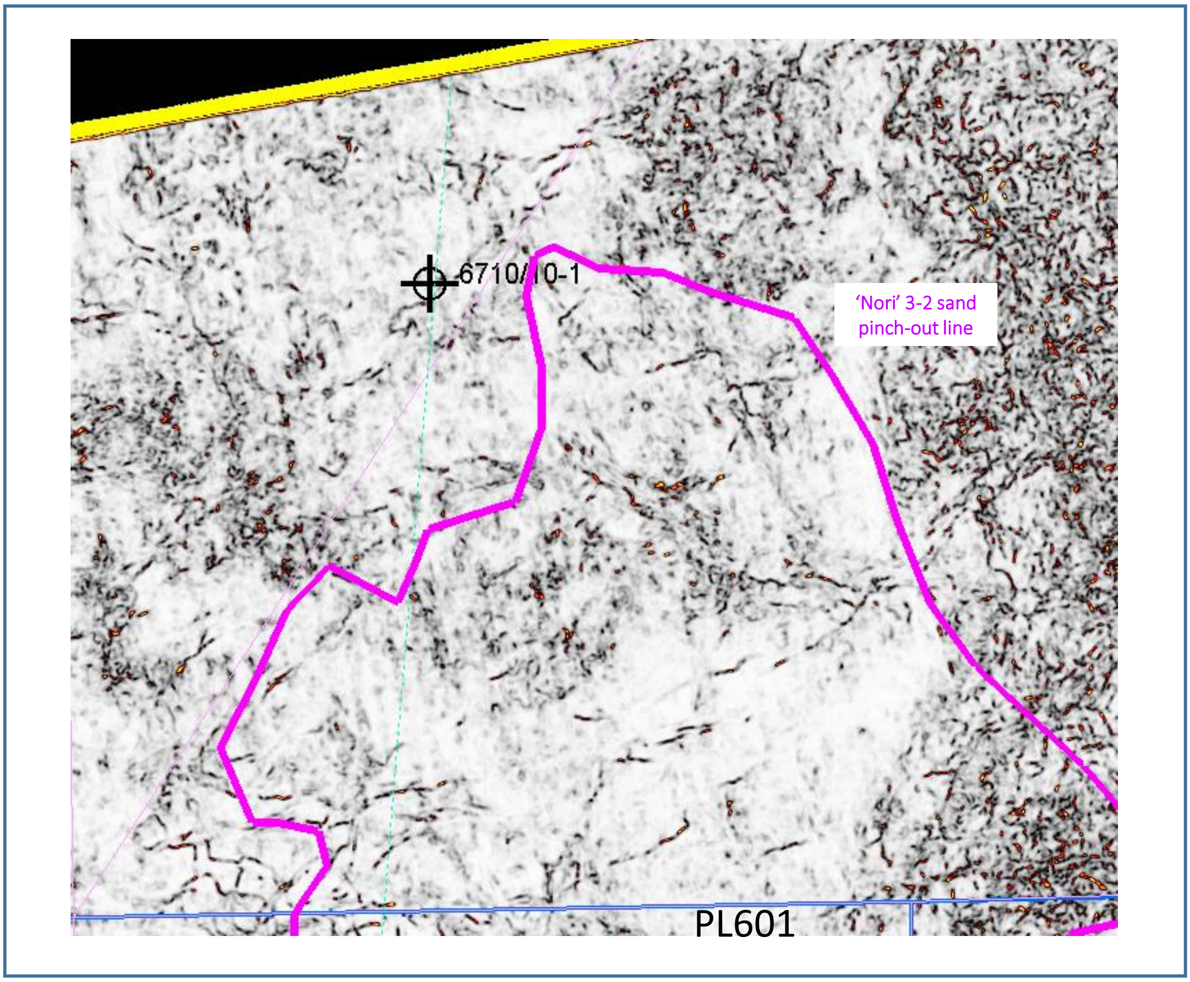


Fig. 4.12 Nori Chaos Extraction

The 6710/10-1 dome appears strongly faulted/ fractured. However the requirement for either a major northeast-southwest hading fault or a linked fault system with the same general strike direction can not be observed. Hence it is likely that the sand bodies are at all levels in communication with the sands encountered in well 6710/10-1

c. Reservoir

The reservoir quality/ connectivity is not seen as a large risk in the Nori prospect, as seen fromFig. 4.13

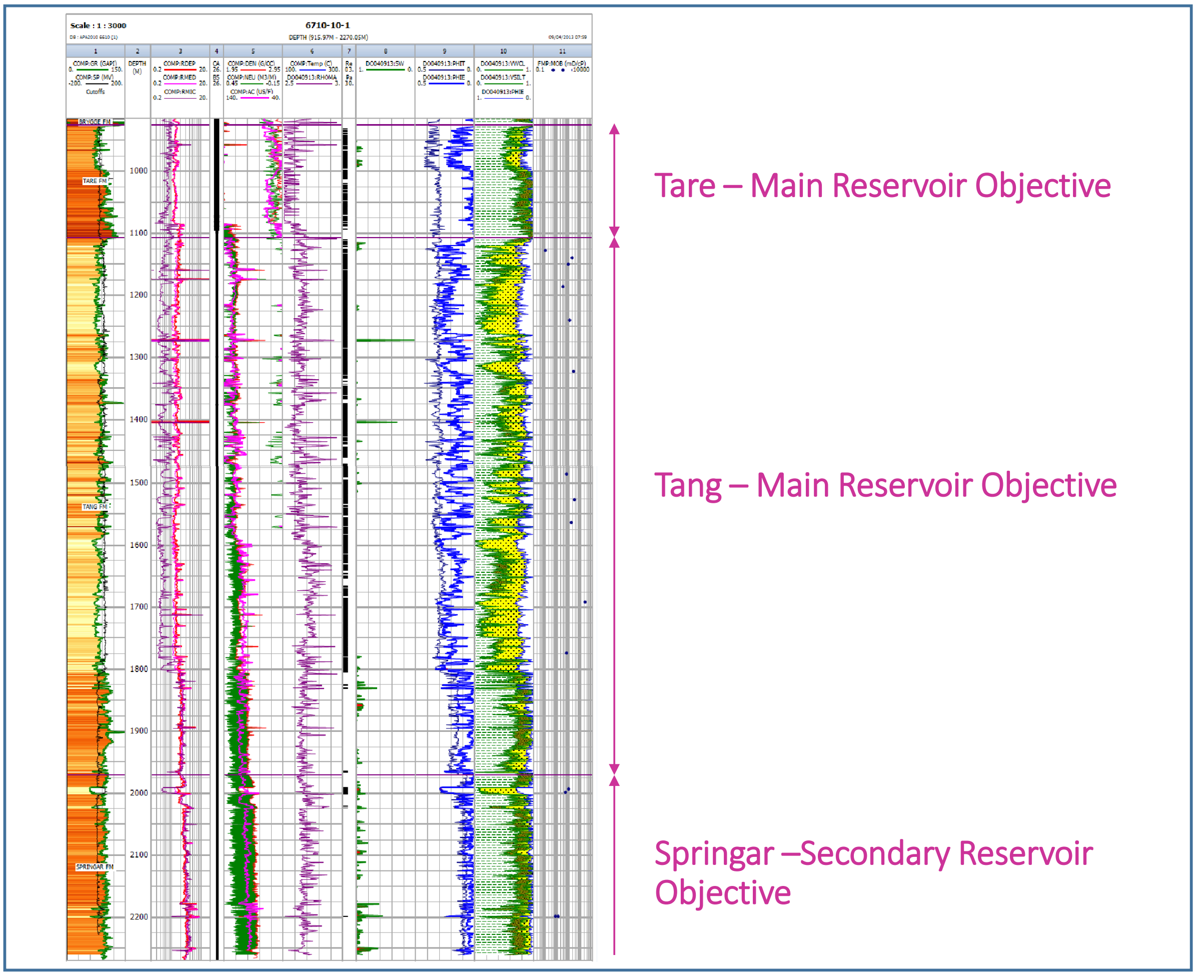


Fig. 4.13 CPI Well 6710/10-1

Most of the Tang Formation is in a sandy facies. However, Tare Fm., Springar Fm. and the lower part of Tang Fm. all exhibit low Net to Gross

d. Seal

Within both Tare and Tang Formations relatively thin shale packages were encountered. With all the post-depositional movement that has taken place, seal continuity across the structure is a serious issue. The same goes for the base seal that the prospect also depends upon. On top of that the prospect depends on complete sand decapitation between the prospect and well 6710/10-1. To that end the two most likely mechanism as illustrated in Fig. 4.5, are sealing fault(s), or turbidite sand onlaps onto an intervening high between Nori and well 6710/10-1. Both these mechanisms depend on favourable conditions, like SGR fault sealing, or absence of sand run-off across a intervening high.

e. Charge

Charge is seen as a more significant risk than reservoir, as hydrocarbons depend on migration through thick shales of Cretaceous age. Offset wells have demonstrated that these shale packages are somewhat overpressered, and may therefore act as vertical barriers to migration.

Also there is the issue of hydrocarbon migration relative to a valid top seal and trap timing. Oil generation may have terminated prior to seal/trap emplacement, leaving the prospect with a very large gas risk.

Blekksprut

Blekksprut is a fault-bounded dip-closure with Paleocene Tang sands as the main reservoir objective, charged from the Upper Jurassic Spekk Formation.

a. Event mapping

The Blekksprut structure is based on the mapped Top Springar event. This event is soft, fairly low amplitude, and in places difficult to pick (Fig. 4.14). The swath reprocessed seismic data improves the continuity of the event. The pre-swath reprocessed data shows the sections above and underneath as hazy, almost transparent, some improvements to these intervals can be seen on the re-processed data (Fig. 4.15).

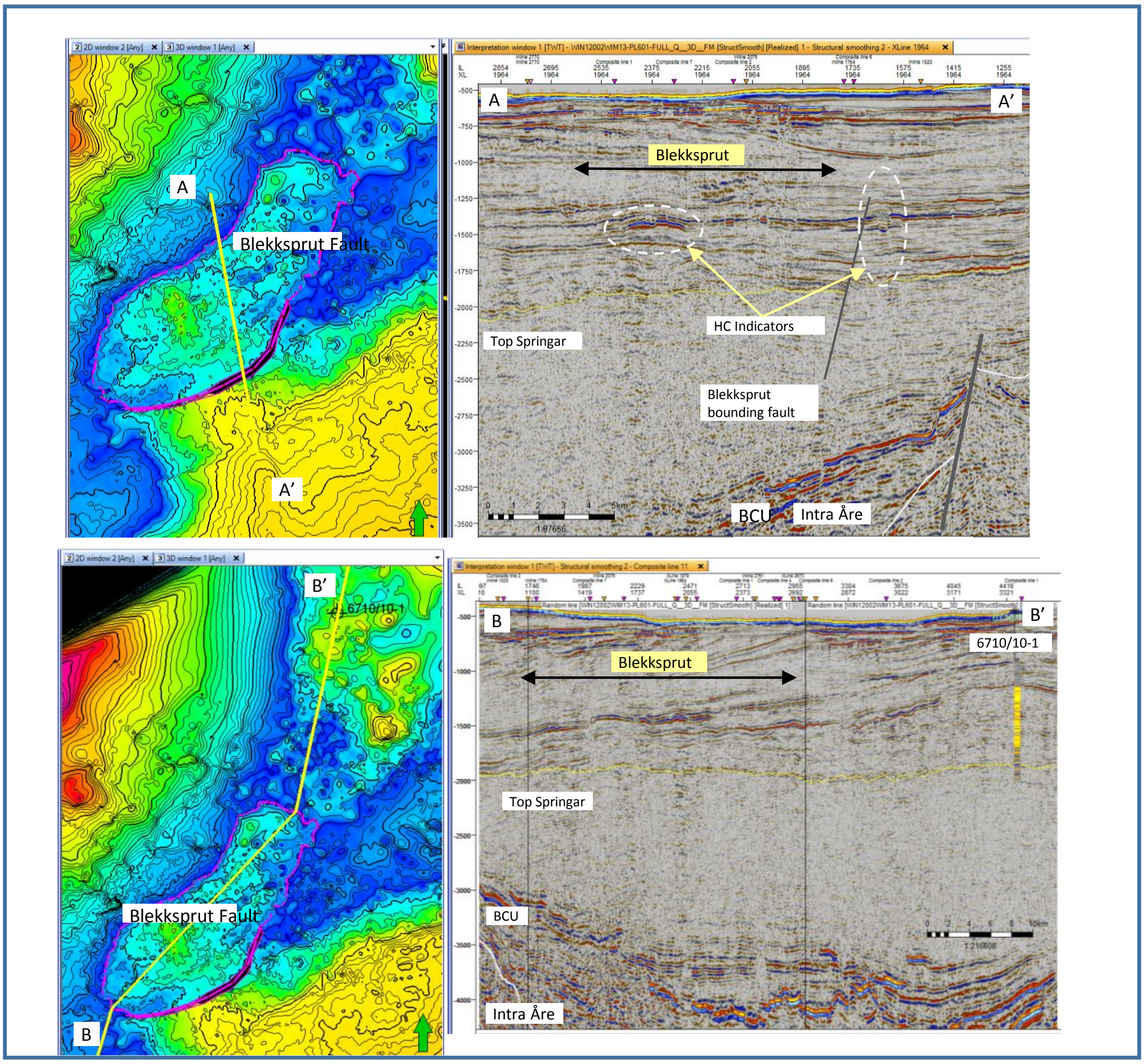


Fig. 4.14 PL 601 Blekksprut Seismic Transects

The seismic transects illustrates the poor seismic expression of the Top Springar pick, which has been used to define the Blekksprut prospect. Also illustrated is the south-eastern bounding fault of Blekksprut

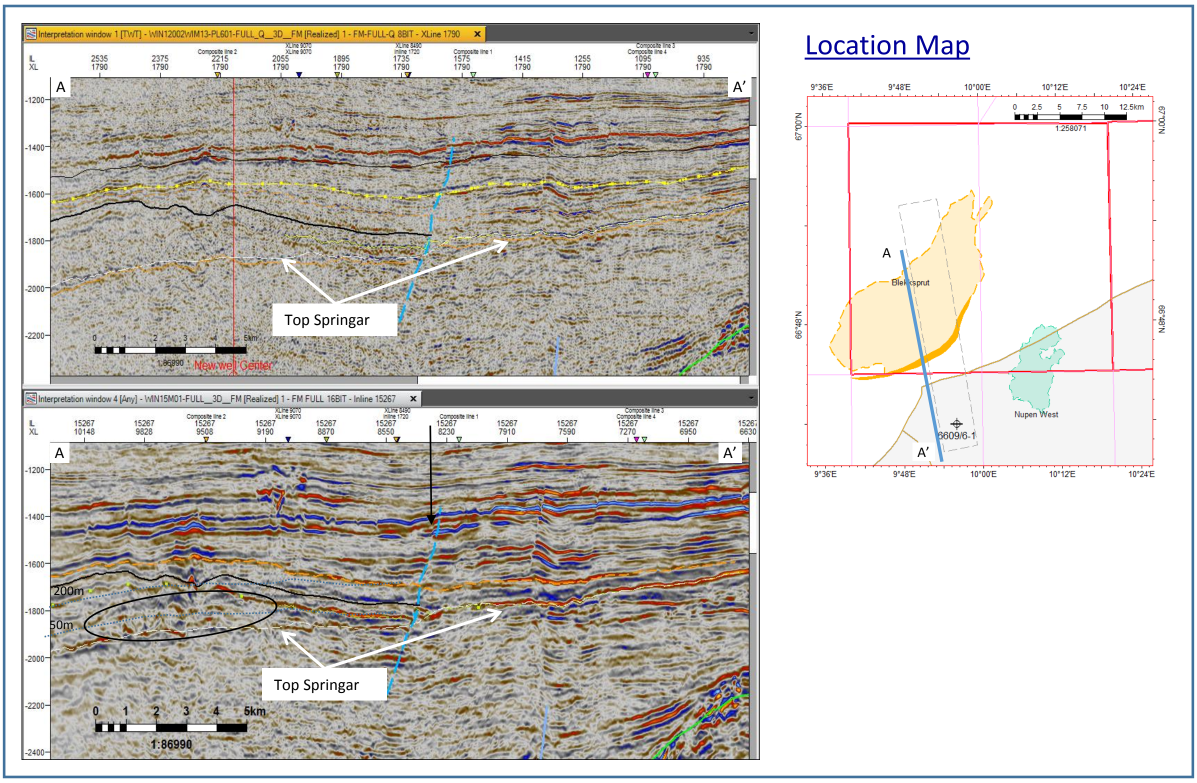
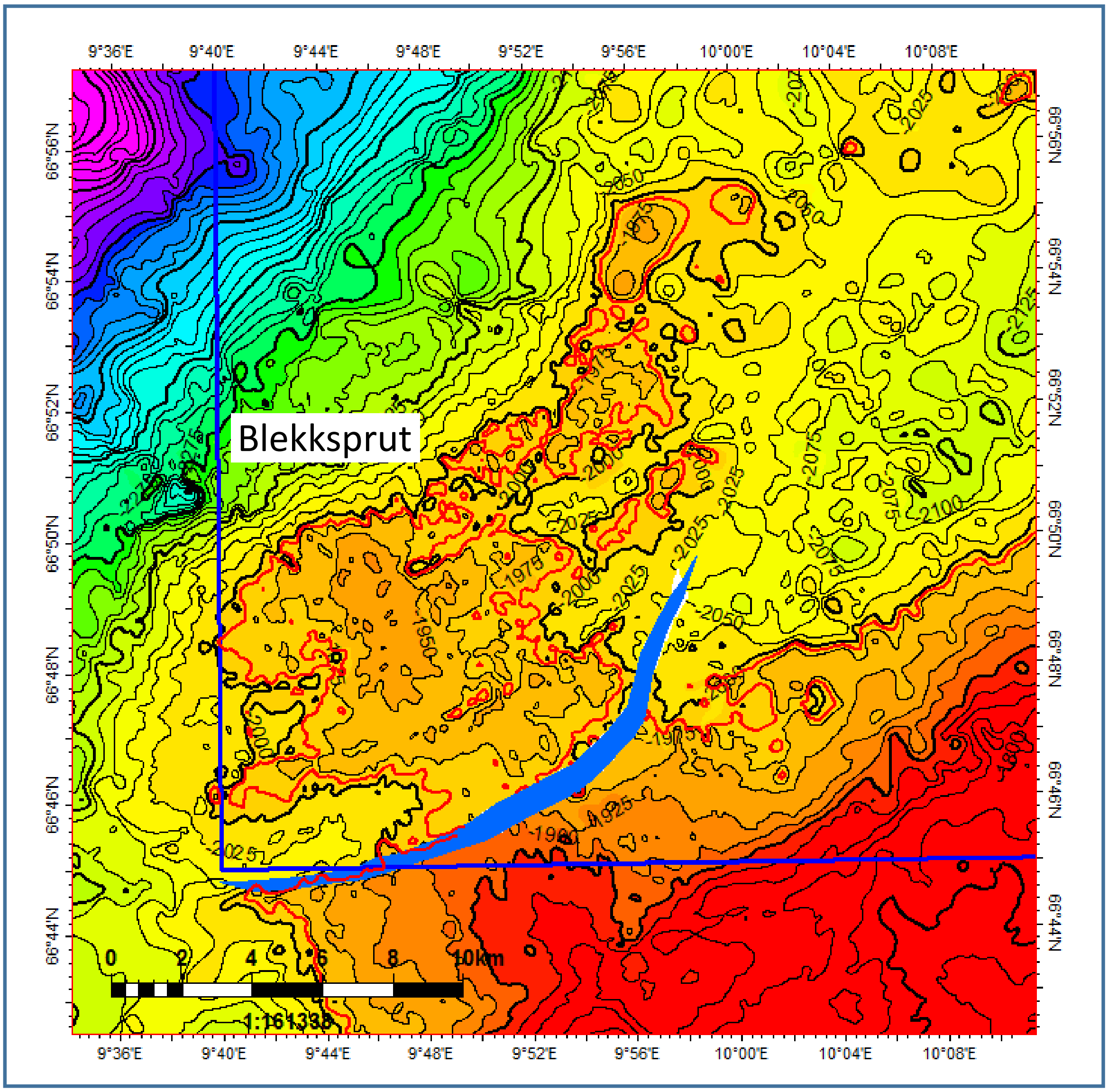


Fig. 4.15 PL 601 Seismic Data Comparison

Seismic Comparison between WIN12002WIM13 (upper transect, reprocessed 2012) and WIN15M01 (lower transect, PSDM reprocessed 2015). A significant imaging improvement can be observed. Downlapping, rather than parallell markers are overlying the Top Springar markers. The sequence also appears chaotic, possibly channelised

b. Trap

Blekksprut is a fairly small dip closed structure, enhanced by a potentially sealing fault located at the south eastern area of the closure (Fig. 4.16). The prospect depends on this fault being at least partially sealing to realise economic volumes. Crest 1920m, spillpoint 2030m, P50 contact 1987m). Max closed are is about 160sqkm.



— : P50 HC Contact

Fig. 4.16 PL 601 Blekksprut Depth Structure

Blekksprut is a dip closure with trap enhancement provided by a NE-SW trending fault, located at the south-eastern side of the prospect

c. Reservoir

The objective reservoir of Blekksprut is Lower Tang sandstone, sealed by Intra Tang marine shales. As the presence and quality of the Tang package, as encountered in well 6710/10-1 is good (Net to Gross 64%). The question is what sand thickness and quality to expect at the Lower Tang level, the interval immediately overlying the Springar Formation (Fig. 4.15) (The Lower Tang section encountered in well 6710/10-1 was argillaceous with low N/G (Fig. 4.13). If this Lower Tang section is assumed to be equivalent to the Egga sands, as encountered further south in the Ormen Lange area, the Gross thickness has to be reduced as compared to assumptions in the original Application Document.

d. Seal

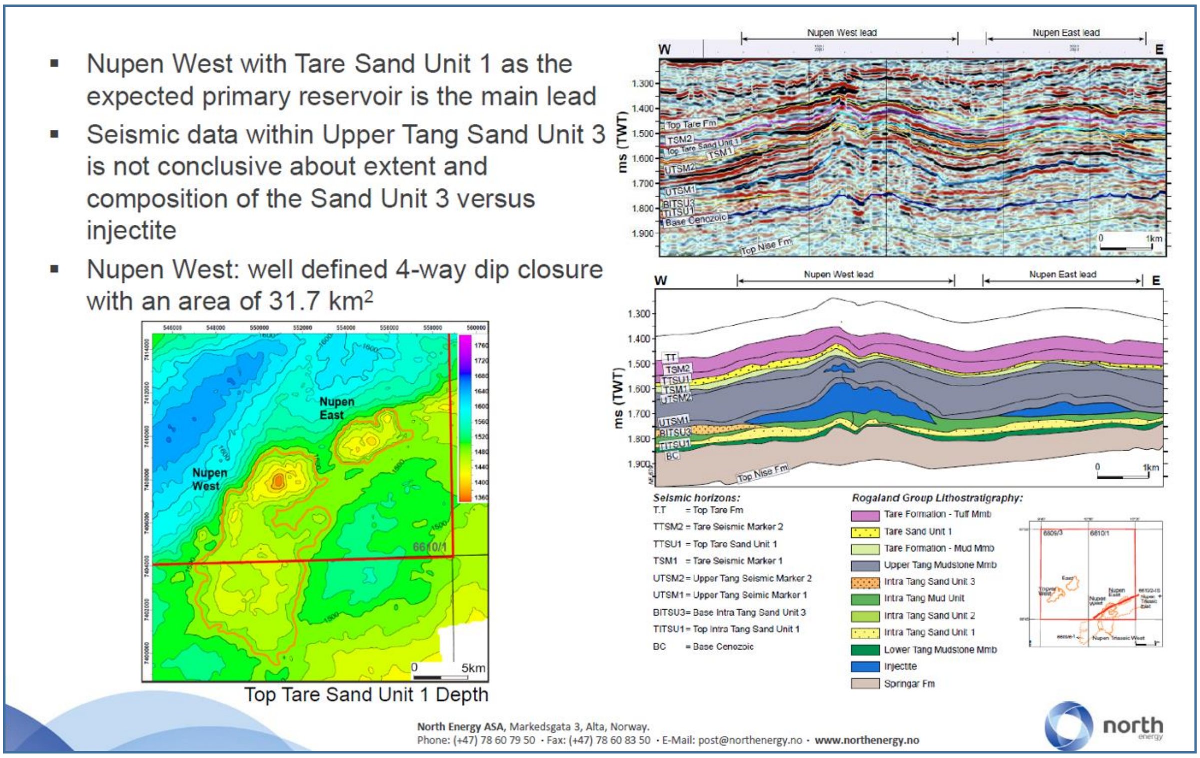
Blekksprut depends on intra Lower Tang seal. As this section has a low N/G the risk of top seal presence is moderate. The top seal continuity across the prospect is more questionable.

e. Charge

See comments under Nori. Since the Blekksprut structure was formed during a Miocene compressional phase, the chance of vertical migration into the Blekksprut Trap from Upper Jurassic Spekk Formation via intervening faults and fractures is higher than for the Nori Prospect.

Nupen West

Nupen West is a dip closed structure straddling the southern border of the PL 601 licence (North Energy Prospect Summary, Fig. 4.17). The core of the structure is a gas injectite. Maximum area of the closure was mapped by North Energy to be about 32sqkm. Primary reservoir target is Tare sands, with Upper Tang as a secondary target.



- Nupen West with Tare Sand Unit 1 as the expected primary reservoir is the main lead
- Seismic data within Upper Tang Sand Unit 3 is not conclusive about extent and composition of the Sand Unit 3 versus injectite
- Nupen West: well defined 4-way dip closure with an area of 31.7 km^2

Top Tare Sand Unit 1 Depth

Seismic horizons:

T.T = Top Tare Fm
TTSM2 = Tare Seismic Marker 2
TTSU1 = Top Tare Sand Unit 1
TSM1 = Tare Seismic Marker 1
UTSM2 = Upper Tang Seismic Marker 2
UTSM1 = Upper Tang Seimic Marker 1
BITSU3 = Base Intra Tang Sand Unit 3
TITSU1 = Top Intra Tang Sand Unit 1
BC = Base Cenozoic

Rogaland Group Lithostratigraphy:

- Tare Formation - Tuff Mmb
- Tare Sand Unit 1
- Tare Formation - Mud Mmb
- Upper Tang Mudstone Mmb
- Intra Tang Sand Unit 3
- Intra Tang Mud Unit
- Intra Tang Sand Unit 2
- Intra Tang Sand Unit 1
- Lower Tang Mudstone Mmb
- Injectite
- Springar Fm

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Fig. 4.17 PL 601 Nupen West (North Energy)

Summary of North Energy interpretation of Nupen West. The prospect has a significant closure (32 sqkm), with about half extending into the block to the south

a. Event Mapping

The Paleocene seismic events mapped in the Nori evaluation were also used to define the Nupen West closure.

b. Trap

The conclusion was that none of the Intra Paleocene markers resulted in Nupen closures the size of what was mapped by North Energy. North Energy. At the intra Paleocene marker stratigraphically closest to Norths Tare marker a closure was mapped very close to the WINO prospect closure called Sjøstjerne in the 21. Round Application Document (Fig. 4.18). (Crest 1410m, Spillpoint 1495m, P50 contact is 1452m with area of about 12,5km2). At all other mapped Paleocene levels the closure was comparable to this, or smaller.

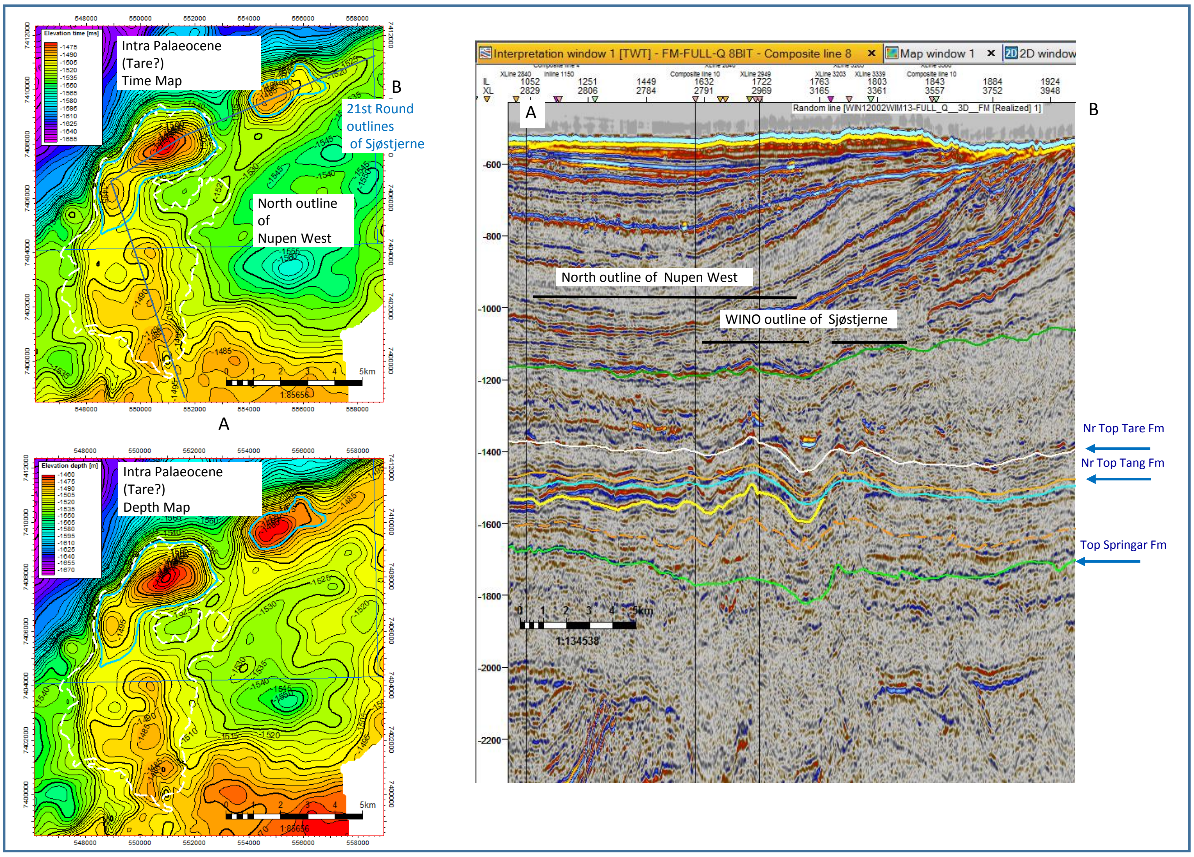


Fig. 4.18 PL 601 Nupen West/ Sjøstjerne

In the operators interpretation the closure of the Nupen West is small (about 13 sqkm)

c. Reservoir

Reservoir is not considered a critical risk for Nupen West, although if Tare is encountered as the main reservoir interval the risk is that the section is tuffaceous, with low N/G. Reservoir input parameters are as per the input from the 21. Round Application Document.

d. Seal

The Lower Brygge Formation is in a shaly facies and should constitute a reliable top seal. For the Intra Tang reservoir objective thin shale continuity across the Nupen West (Sjøstjerne) prospect is an issue.

e. Charge

With the presence of a vent at the core of the structure there is a fairly low risk of charge in Nupen West. However, the underlying Spekk Formation does not seem to have a significant drainage area into this prospect. In addition gas charge is an obvious risk for this prospect, as for Nori and Blekksprut.

AVO SCreening

In order to investigate hydrocarbon presence in the block generally, and for the highest ranked prospect specifically, an AVO screening exercise was carried out.

As a follow-up of a Mid Norway AVO modelling study, the 3D seismic data PSTM 3D streamer seismic (nears /mids /fars) were analysed for AVO effects. The modelled data of well 6710/10-1 (located in the survey) were selected for the calibration of the reconnaissance AVO attributes

(Fig. 4.19). The nears / mids / fars were combined to form 3-fold angle gathers (7, 22 and 37 degrees incidence angles). Angle gathers were RMS normalised by scalar derived from window 700ms - 2700ms.

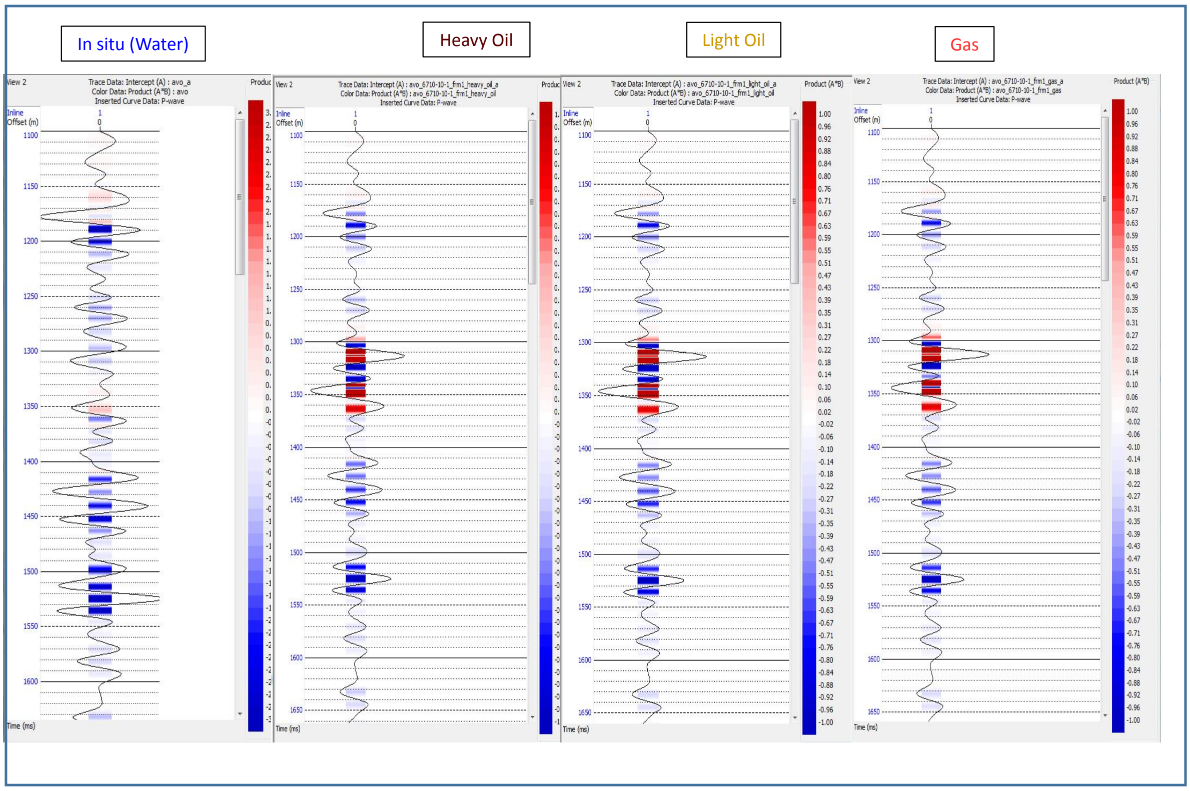


Fig. 4.19 PL 601 Well 6601/10-1 AVO Modelling
The log display shows that a high amplitude expression should be expected at objective Tang level for all possible HC types

The resulting I*G (Intercept*Gradient) AVO attribute matched the synthetic I*G attribute derived on well 6710-10-1 quite well.

From AVO modelling, HC's at the target (TANG sands and below) should generate a strong AVO effect that would result in a distinct AVO class 2/3 anomaly, and a strong positive Intercept* Gradient AVO product. The I*G product only shows very weak positive I*G values at target (Fig. 4.20) illustrated on volume transects shown in Fig. 4.21 and Fig. 4.22, that can be in interpreted as water bearing sands (like well 6710/10-1).

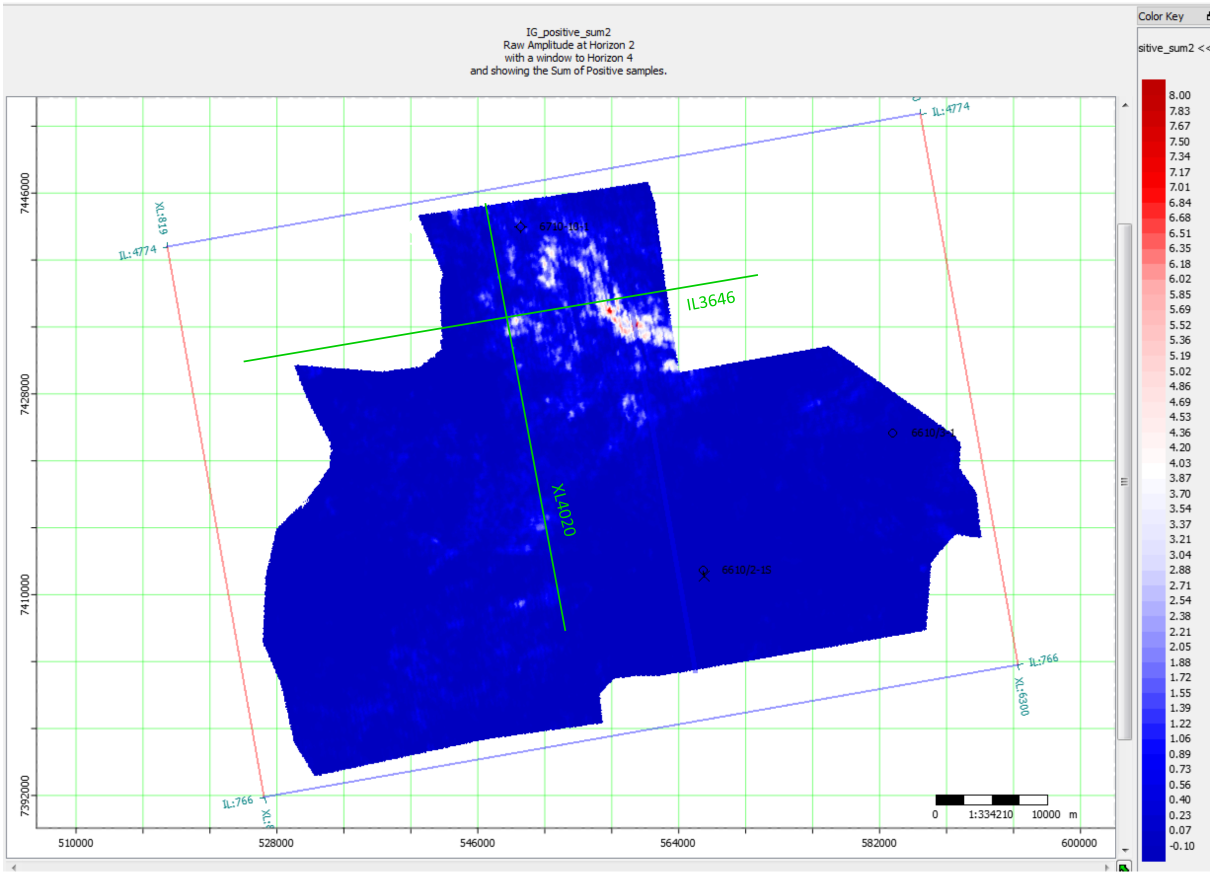


Fig. 4.20 AVO Modelling Map

*3D seismic: Map of sum of positive samples between Horizon2 and Horizon4-I*G AVO attribute. The only positive response is located outside the PL 601 area*

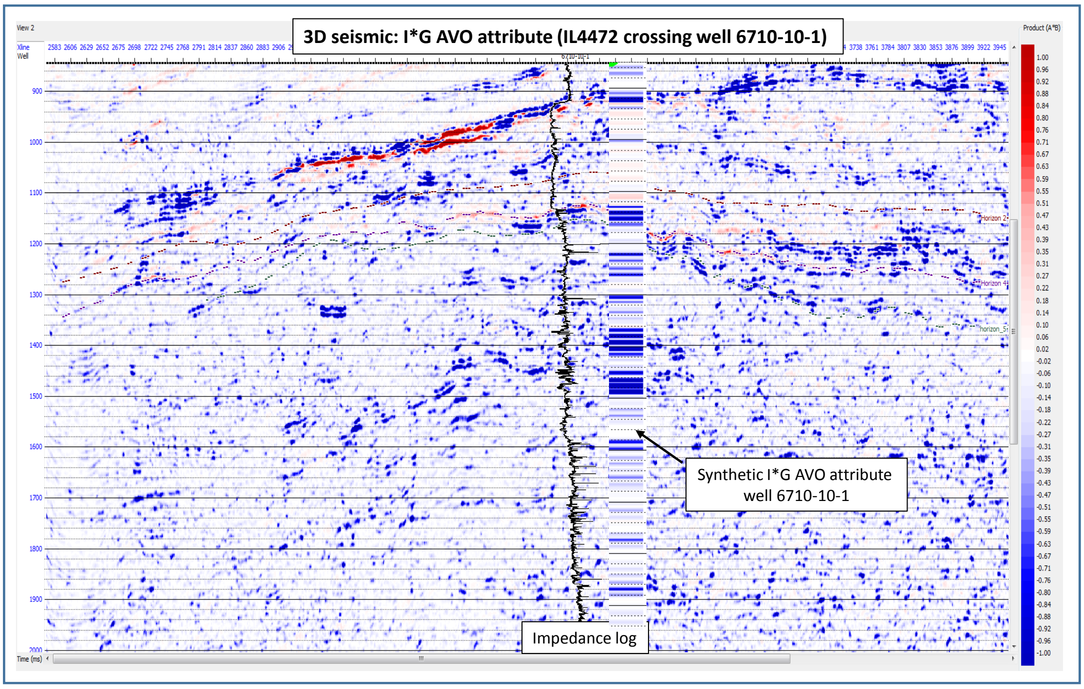


Fig. 4.21 PL 601 AVO Modelling

*The line illustrates tie between the seismic I*G volume and well. The tie is considered good*

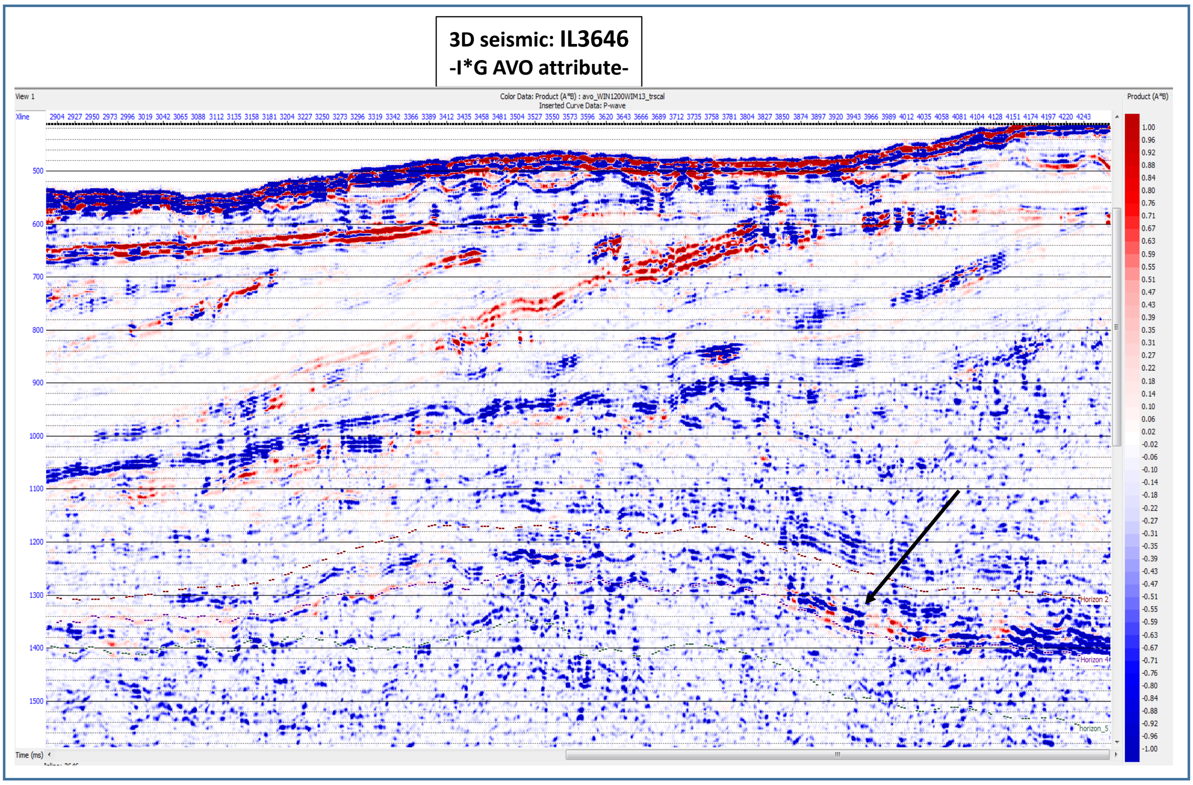


Fig. 4.22 PL 601 AVO Analysis Transect

*The I*G response in the objective lower half of the section is weak (see scale), while in the shallower section the response is stronger and could be indicative of hydrocarbons presence*

4.2 Resource Estimation

Summary of selected Mean Parameter Input is shown in Table 4.2. Prospect Volumetrics estimates is summarised in Table 4.3

Table 4.2 PL 601 Selected Prospect Volume Input Parameters

Prospect	Crest (m)	Spill point (m)	Gross Reservoir (m)	N/G (%)	Porosity (%)	Oil Rec. Factor (%)
Nori	975	1092	104	49,6	23,9	29,5
Blekksprut	1920	1977	67	45,4	24,4	29,5
Nupen	1370	1452	242	48,2	22,6	35

Table 4.3 PL 601 Prospect Volume Estimates

PL601 Main Prospects		(mmbbls oe.)				(%)
Prospect		Mean	P90	P50	P10	GPOS
Nori	Used Intra Paleocene 2 for volume estimation. Gross: 2-3 interval	**408**	**16**	**249**	**1012**	6
Blekksprut	Assumed Egga Sands analogue, with lognormal HC contact distribution down to ultimate spill point (2030m)	**150**	**7**	**77**	**385**	**12**
Nupen West/ Sjøstjerne	Volumetrics from APA2011	**17**	**1**	**9**	**41**	**19**

Nori Prospect.
Mean volumes of the Nori prospect is estimated to about 400 mmbbls oe, i.e. a potentially large prospect . However, the main body of the prospect is located in the block to the north of PL 601, approximately 10% is located in a down-dip position in PL 601 license.

Blekksprut Prospect.
For Blekksprut a few sensitivity runs were done, varying reservoir thickness and spillpoint. These runs calculated P50 volumes from 23 mmbbls (Mean38 mmbbls) at dip-closure spillpoint, with Egga sand thickness to 77 mmbbls (150 mmbbls mean) with maximum spillpoint and Egga sand thickness. All the sensitivity runs returned volumes below or about at economic cut-off.

Nupen West (Sjøstjerne).
Sjøstjerne volumretrics estimate resulted in a P50 volume of about 9 mmbbls oe (17 mmbbls oe mean).

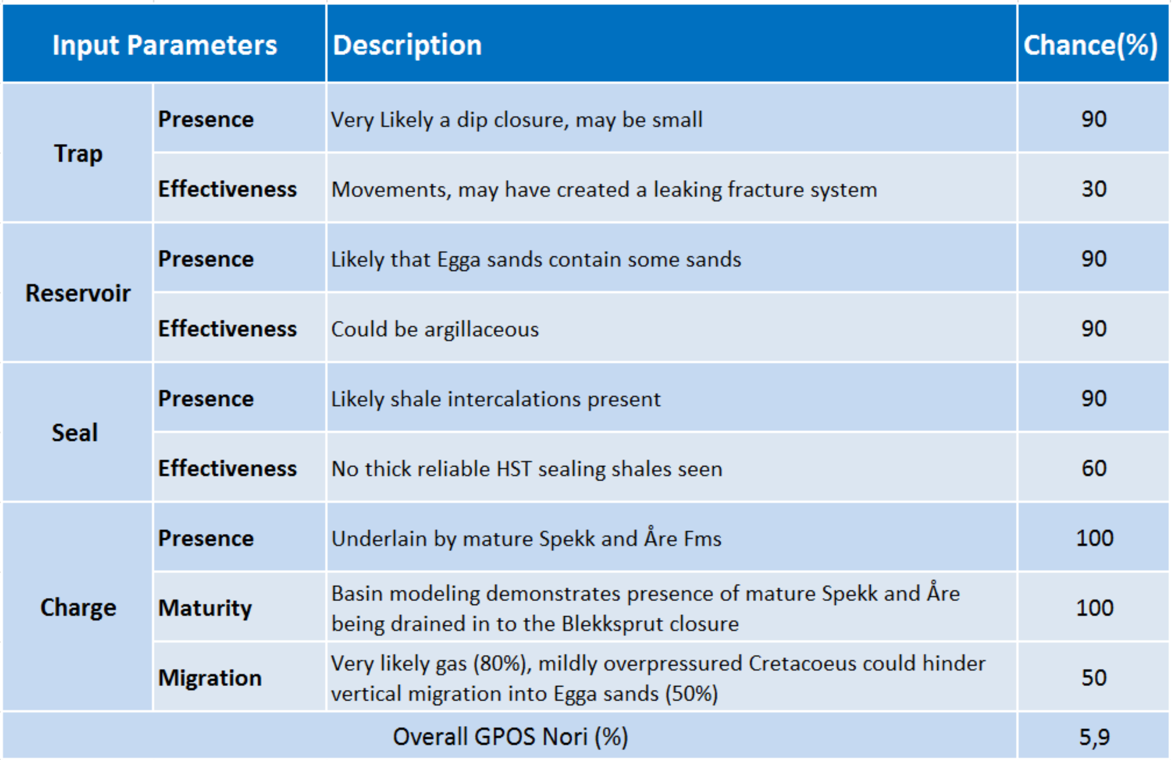
4.3 Prospect Risking

Prospect risking.

Nori

This prospect is evaluated to have a GPOS of about 6%. Summary of the Risk assessment is in Table 4.4. The main risk elements are Trap Effectiveness (30%), Seal Effectiveness (60%) and Charge Migration (50%). This risk assessment is excluding the additional risk of gas charge.

Table 4.4 Nori Risk Summary

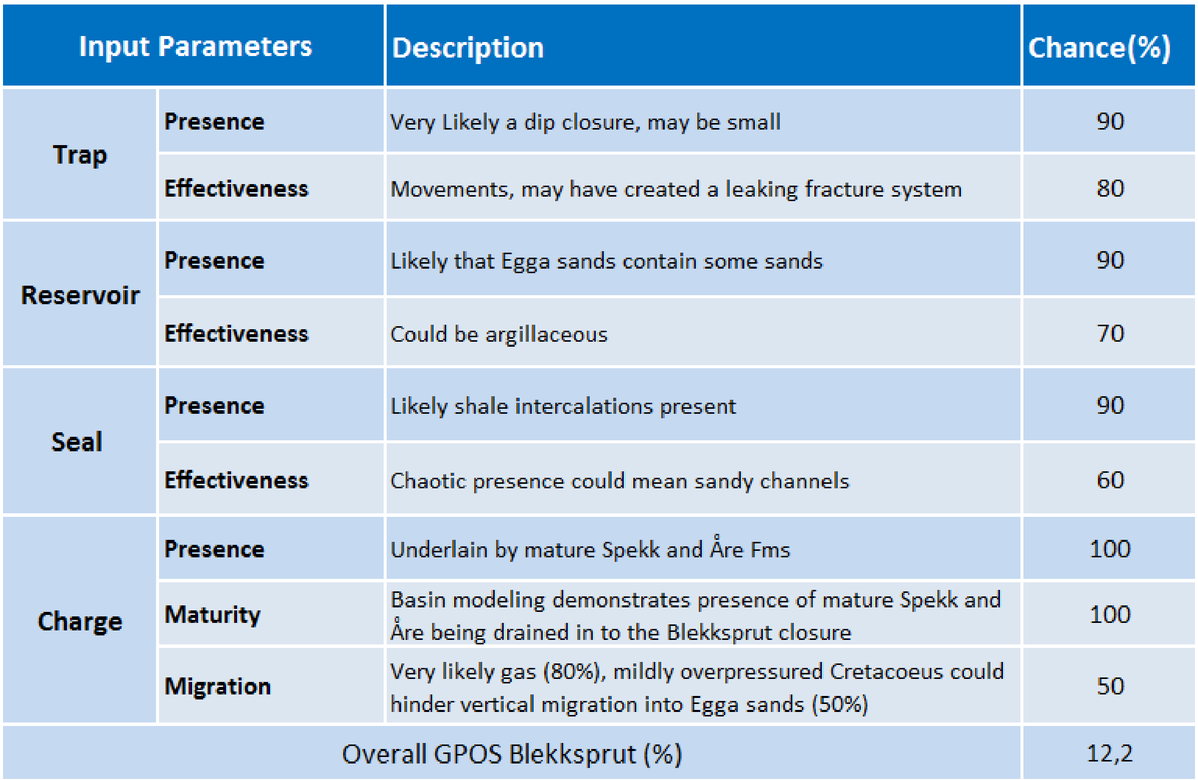


Input Parameters		Description	Chance(%)
Trap	Presence	Very Likely a dip closure, may be small	90
	Effectiveness	Movements, may have created a leaking fracture system	30
Reservoir	Presence	Likely that Egga sands contain some sands	90
	Effectiveness	Could be argillaceous	90
Seal	Presence	Likely shale intercalations present	90
	Effectiveness	No thick reliable HST sealing shales seen	60
Charge	Presence	Underlain by mature Spekk and Åre Fms	100
	Maturity	Basin modeling demonstrates presence of mature Spekk and Åre being drained in to the Blekksprut closure	100
	Migration	Very likely gas (80%), mildly overpressured Cretacoeus could hinder vertical migration into Egga sands (50%)	50
Overall GPOS Nori (%)			5,9

Blekksprut

Blekksprut is evaluated to have a GPOS of about 12%. Summary of the Risk assessment is inTable 4.5. The main risk elements are Reservoir (63%), Seal (54%) and Charge (50%)

Table 4.5 Blekksprut Risk Summary



Input Parameters		Description	Chance(%)
Trap	**Presence**	Very Likely a dip closure, may be small	90
	Effectiveness	Movements, may have created a leaking fracture system	80
Reservoir	**Presence**	Likely that Egga sands contain some sands	90
	Effectiveness	Could be argillaceous	70
Seal	**Presence**	Likely shale intercalations present	90
	Effectiveness	Chaotic presence could mean sandy channels	60
Charge	**Presence**	Underlain by mature Spekk and Åre Fms	100
	Maturity	Basin modeling demonstrates presence of mature Spekk and Åre being drained in to the Blekksprut closure	100
	Migration	Very likely gas (80%), mildly overpressured Cretacoeus could hinder vertical migration into Egga sands (50%)	50
Overall GPOS Blekksprut (%)			12,2

Nupen West
This prospect is evaluated to have a GPOS of 19%. The main risk elements are seal (54%) and charge (60%).

4.4 Technical reservoir conditions

All three prospects are assumed to be hydrostatically pressured.

5 Technical evaluations

A standalone FPSO Development in the area of PL 601 has been evaluated, with the following assumptions:

- Added cost of standard development for subsea equipment and gas evacuation to Aasta Hansteen (100km), implying an extra cost of 15 mrd NOK
- Same prices and exchange rates as oil MEV assumptions
- Tariffs for processing of gas through Aasta Hansteen and Polarled included
- Same profile for gas as for oil

Based on the assumptions an MEFS (Minimum Economic Field Size) for oil is estimated to about 125 mmbbls oil. MEFS for gas is estimated to be in excess of 2 TCF.

6 Conclusions

The three highest ranked prospects in PL 601 all fall short of qualifying for a well test.

1. Nori has too high geological risk, with only a small part of the volumes located in PL 601

2. Blekksprut has too small volumes for economic development. In addition the geological risk is too high, particularly related to top seal and charge

3. Nupen lead is too small to warrant a test by the drill bit

All three prospects have a high risk of encountering gas rather than oil.

7 References

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