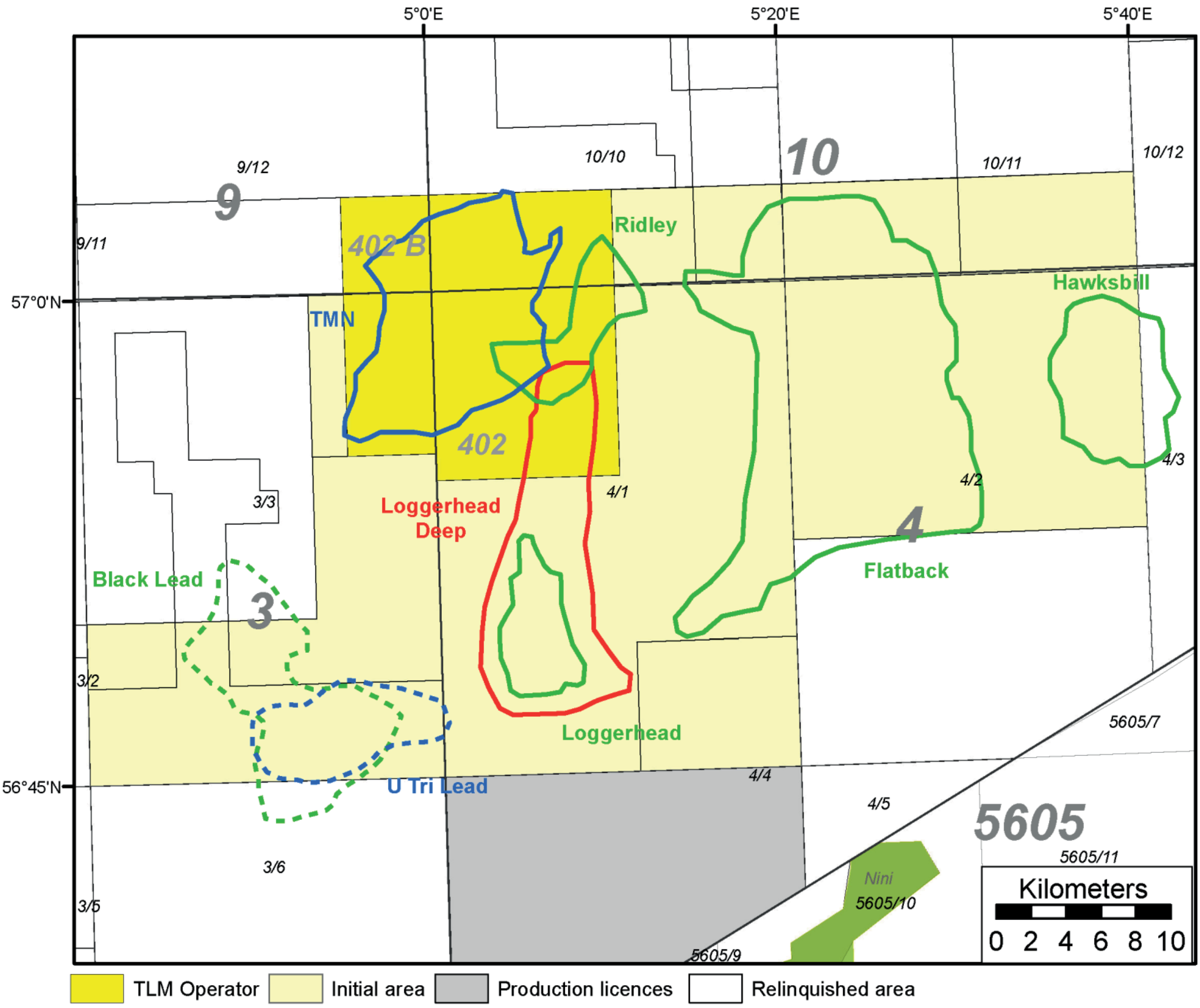
PL402 & PL402b Relinquishment Report

September 2013



TALISMAN ENERGY

PL402 and PL402B Relinquishment Report

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1 Key License History

1.1 Executive Summary

The 402 and 402B licenses are located in the Danish-Norwegian Basin. This is an area located at far distance to the east from the main oil province in the Central Graben. The nearest field is the Harald Field located 80 km to the south in the Danish sector.

PL402 was applied for in APA 2006 and awarded in February 2007. PL402B was applied for as a licence extension in APA 2008 and was awarded in January 2009. The current licenses areas are results of several steps of relinquishment , that has been done in order to optimise the work to the highest ranked prospect (TMN prospect). Figure 1.1 shows an overview of current versus initial licence acreage in addition to outlines for defined prospects and leads.

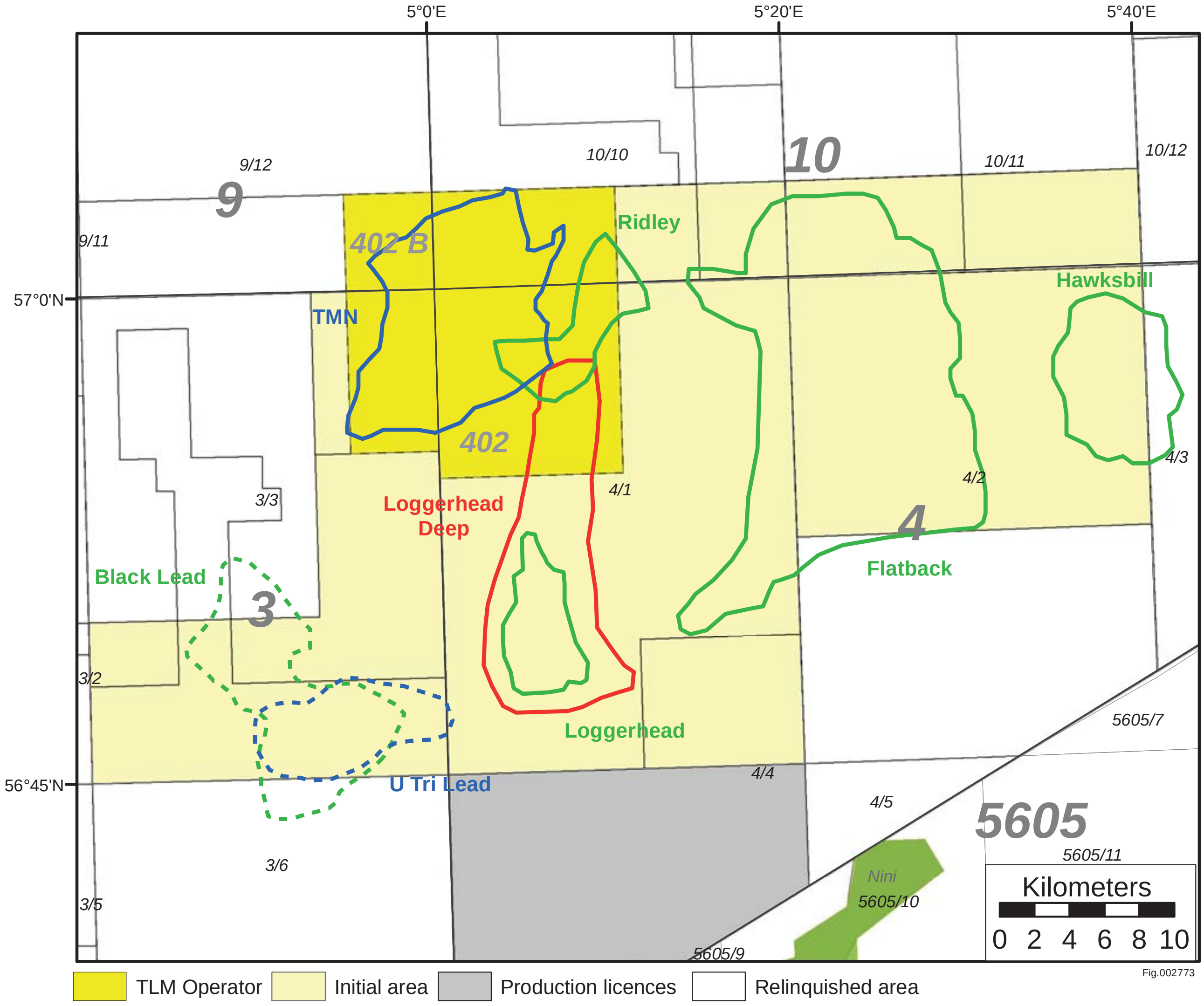


Figure 1.1 PL402 and PL402B licensed area historic

The main play in the license area is in the Jurassic and Triassic reservoir intervals. The primary risk is related to source and charge of hydrocarbons. The prolific known Upper Jurassic source rock is immature in the area, and prospectivity depend on a deeper Carboniferous source which is not yet proven in the norwegian part of the North Sea.

The licence work program is listed in section 1.2 Work program and duration, and has been fulfilled with the exception of the drilling of one firm exploration well. The main objective to obtain new data gathering and conducting studies was to reduce risk and to improve the understanding of prospectivity. Results of studies has lead to the opposite; a marked increase in geological risk has been defined. As a result the likelyhood for an economic viable discovery is now regarded as small.
Based on this conclusion PL 402/402 B applied to be excempted for the firm drilling obligation and is also the basis for relinquishing the acreage in full.

1.2 Work program and duration

PL402 is located in the Danish-Norwegian basin. The Operator is Talisman Energy Norge AS (80%) and Petoro is partner (20%). PL402B was awarded as an licence extension as protection acreage to the TMN prospect. The PL402B was awarded in 2009 with the same terms and conditions as for PL402. Figure 1.1 shows the areal extent of the initial licence acreage.

Initial work obligations in the licenses are listed below:

- Acquire more than 550km2 3D seismic data
- Reprocess existing 3D data
- Perform geological studies
- Drill one firm exploration well to TD in rocks of Triassic age.

The main part of the work programme was performed during 2008 and 2009 Figure 1.2 although updates and inclusion of information has been don up to 2012. In May 2008 a site-survey and shallow boreholes was drilled to prepare the TMN prospect for drilling.

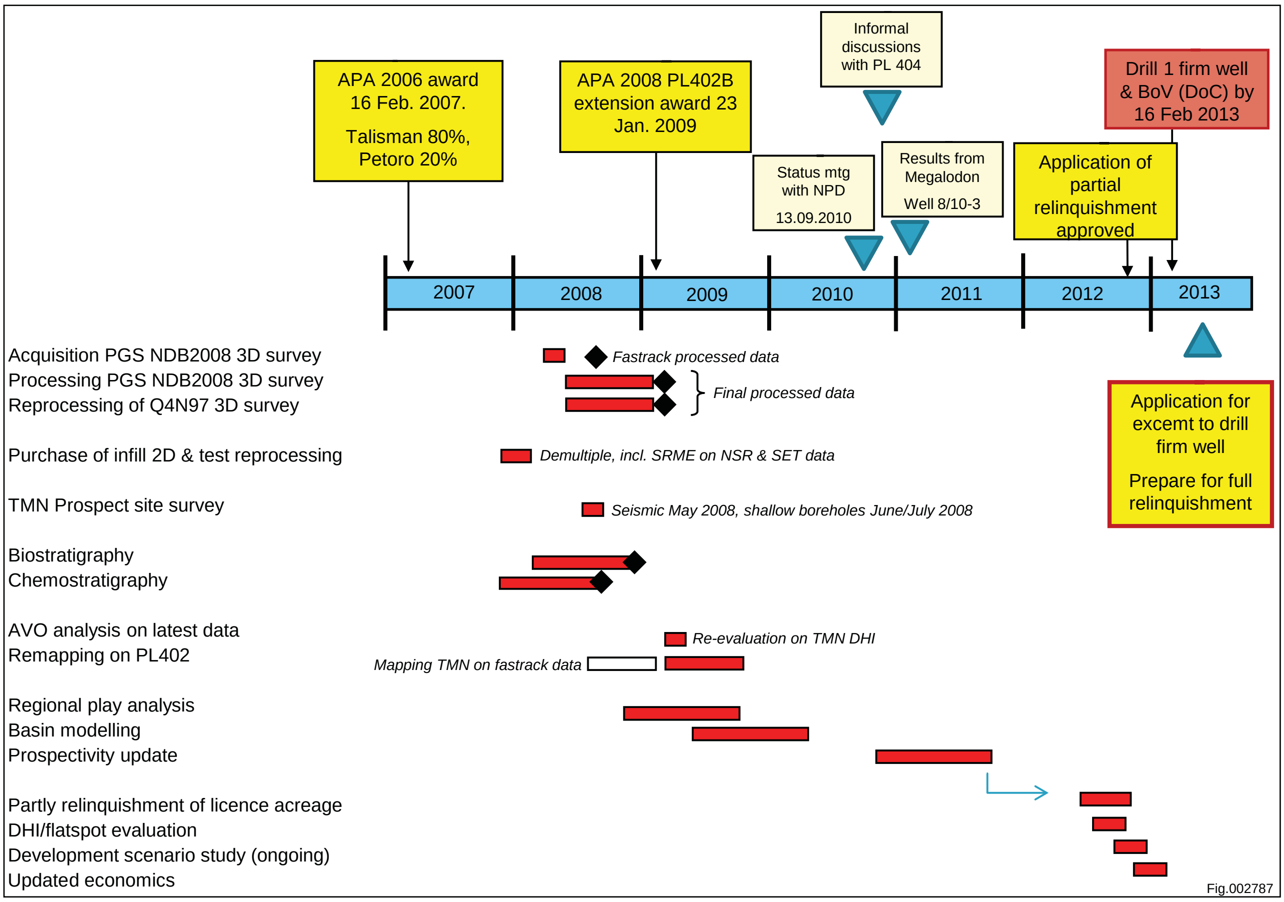


Figure 1.2 Licence history

During the history of the licenses, the owners have applied for extension of deadlines for various reasons. The main focus has been to obtain information and to de-risk the prospectively as much as possible prior to taking a drill decision.

Applications and grants for extension of deadlines can be summarised as follows:

- BoV (DoC) extension to 16.02.2013 and PDO to 16.02.2015 was approved in 2011.
- BoV (DoC) extension to 16.02.2015 and PDO to 16.02.2017 was approved in 2013.

The resulting license area as seen in Figure 1.1 is a result of several steps of relinquishment's:

- 2007:1414 km^2 PL402
- 2009:1414 km^2 PL402 and 28 km^2 PL402B
- 2012: 1034 km^2 PL402 and 28 km^2 PL402B
- 2013: 218 km^2 PL402 and 28 km^2 PL402B

2 Database

2.1 Seismic database

The 2D and 3D seismic data used for PL402/PL402B evaluations are listed below and shown in Figure 2.1

- MC3D-NDB2008 3D was acquired by PGS from March to May in 2008. A total of 794 full-fold km2 was acquired. The fast track cube was delivered in August 2008 and final data delivered for interpretation in February 2009.
- The existing 3D survey Q4N97 3D was reprocessed to a total of 1640 km2 full-fold data. The processing sequence was based on NDB2008 3D and adapted for different geometry. The final data was delivered in February 2009.
- 2D data used in initial evaluations consisted of various released 2D surveys. A total of 164 km 2D lines were also reprocessed.
- A seismic site survey covering the TMN prospect was acquired during summer 2008.

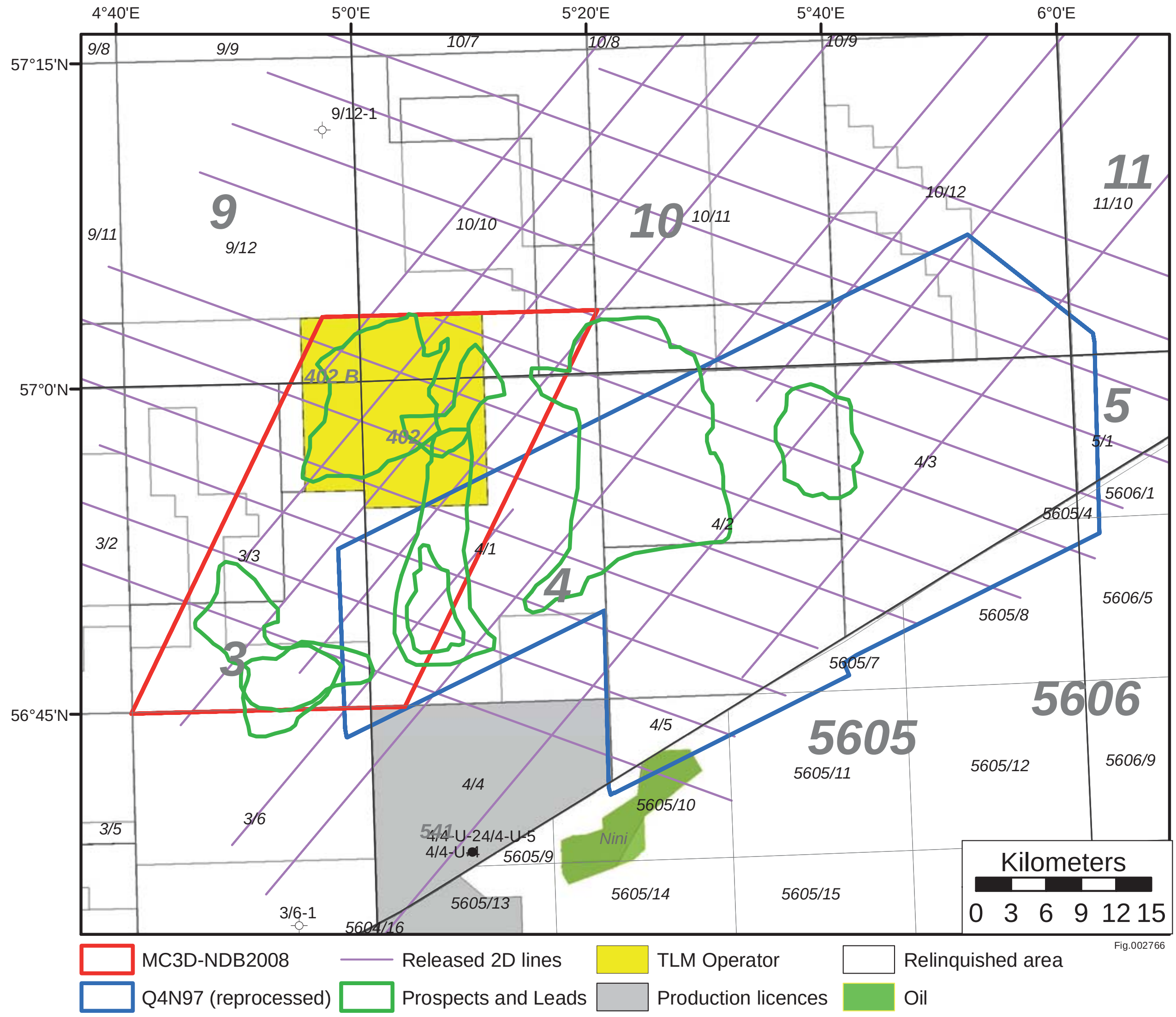


Figure 2.1 Seismic Database

2.2 Well database

Well data used in PL402/PL402B evaluations are shown in Figure 2.2.

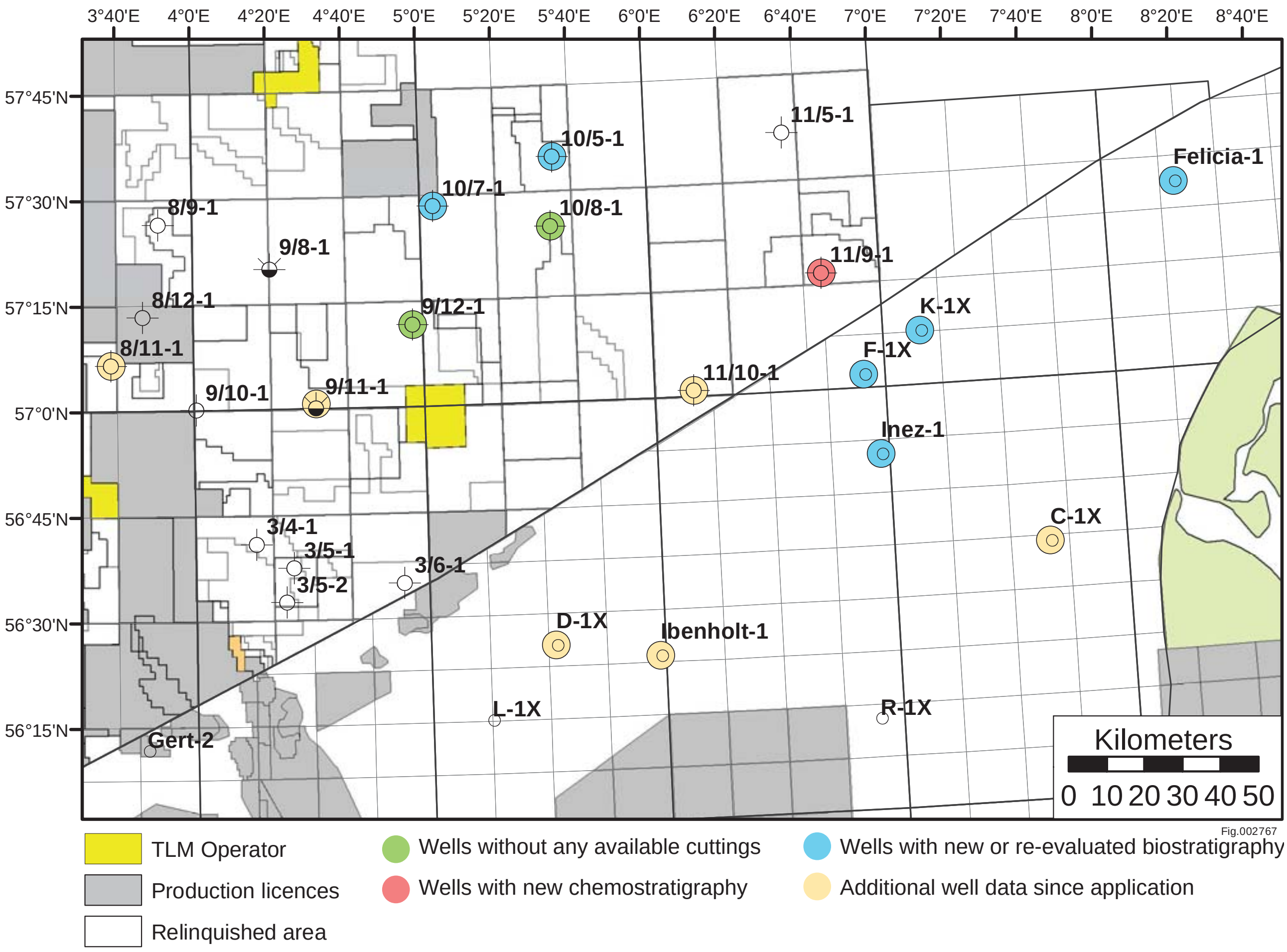


Figure 2.2 Well Database

Note that in addition to the Norwegian wells also some Danish wells were evaluated. The licence purchased well data from GEUS to build a broader regional understanding. The purchased Danish wells are: Felicia-1, Inez-1, Ibenholt-1, C-1, D-1, F-1, K-1, also shown in Figure 2.2.

2.3 Studies

Several comprehensive studies have been performed in the licenses since award. The purpose of studies have been to increase confidence in the geological and geophysical understanding of area potential. An overview of studies performed within PL402 /PL402B are listed below:

- Biostratigraphy & Correlation Study, GEUS, Feb. 2008 - Dec. 2008. Study was performed in order to achieve consistent analysis allowing correlation through 12 offset wells (Triassic - Lower Cretaceous) and extending the stratigraphic framework established in the Danish wells (Nielson, 2003) to the Norwegian wells around PL402. Study included new biostratigraphic analysis on 10 wells: Norway 8/11-1, 9/11-1, 10/5-1, 10/7-1, 11/10-1; Denmark Felicia-1, Inez-1, Hyllebjerg-1, F-1, K-1
- Chemostratigraphy Study, Chemostrat Ltd., Dec. 2007 - Aug. 2008. Focus for study was to differentiate Jurassic and Triassic intervals, and provide a correlation tool allowing stratigraphic

correlation of offset wells into more proven and better understood areas of the Triassic play with established regional chemostratigraphic frameworks (e.g. Central Graben)

- Surface Geochemical analysis. Purchase of Geolab Nor AS analysis. Geochemical seabed sampling and analysis in Norway Quad 3 & 4 survey (1996).
- AVO Analysis (incl. spectral analysis). Focus was to identify potential DHI's, shallow gas and to understand intra-Triassic seismic amplitude responses.
- Basin Modelling: 1D modelling done by basin modelling experts in Calgary. Focus for study was maturity of source rock and migration of hydrocarbons versus timing for structures.

3 Review of geological framework

The Norwegian-Danish Basin is part of an extensive system of Triassic basins (Figure 3.1). These extend from the Møre Basin in the north through the North Sea Viking Graben system and into the Central Graben and Norwegian-Danish Basin. The Norwegian-Danish Basin then extends south-eastwards through Denmark and into Germany and Poland, and through the Horn Graben and the Central Graben to the southern North Sea Basins of the UK and the Netherlands. Possibly the least explored of these Triassic basins is the Norwegian sector of the Norwegian-Danish Basin.

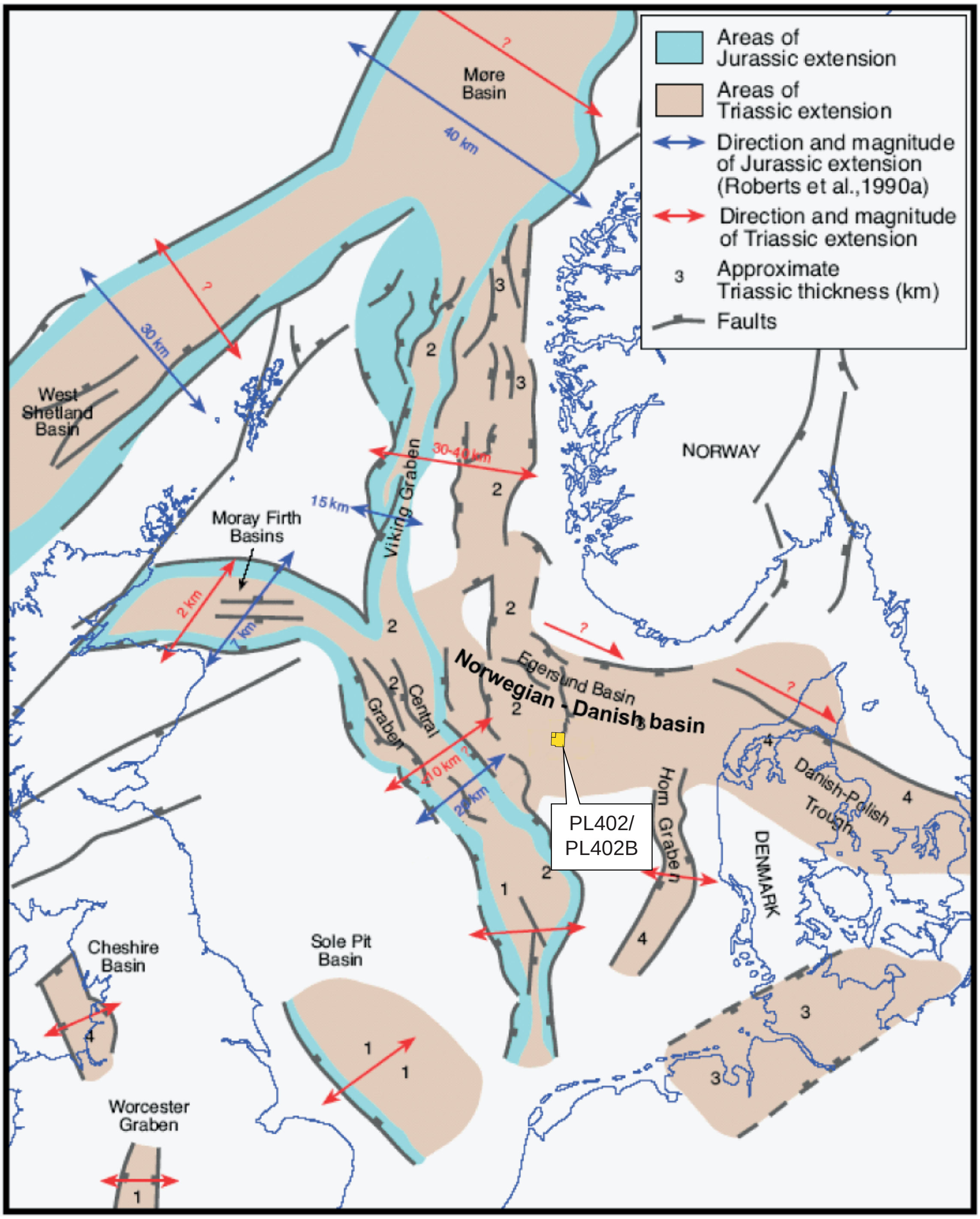


Figure 3.1 North Sea Triassic basins. *From APA application for license extention 2008*

The main prospectivity in the area is defined on so called turtle structures formed by Permian Zechstein salt movement above pre-existing Permian structural elements. The main reservoir section was interpreted to be Gassum/ Skagerrak Bunter Fm. sandstone of Triassic age. A litho-stratigraphic column is shown in Figure 3.2. The salt has also formed a series of NNW-SSE oriented salt walls and diapirs. The model is that Triassic sediments have been channeled down between the salt walls and diapirs as these would have formed subtle hills at the time of deposition. Figure 3.3 shows the concept for sand distribution for the play. A play summary diagram is shown in Figure 3.4. Geological studies performed by the license have resulted in an increased risk for the reservoir. The highest ranked prospect in area is the TMN prospect. The TMN structure is a 4-way dip closure, within the Upper Triassic, mapped on 3D seismic data. There is however a fault that goes through the structure. This is a major risk in relation to top seal, and introduced a higher risk for the prospect than initially believed. One incentive for the original APA application, was the observation of an DHI within the mapped closure. License work has shown this to not be conform with structure. It is now believed that the increased amplitude values most likely is related to a salt tongue in relation to the salt structure forming the TMN trap. This also increase the risk for TMN not holding hydrocarbons.

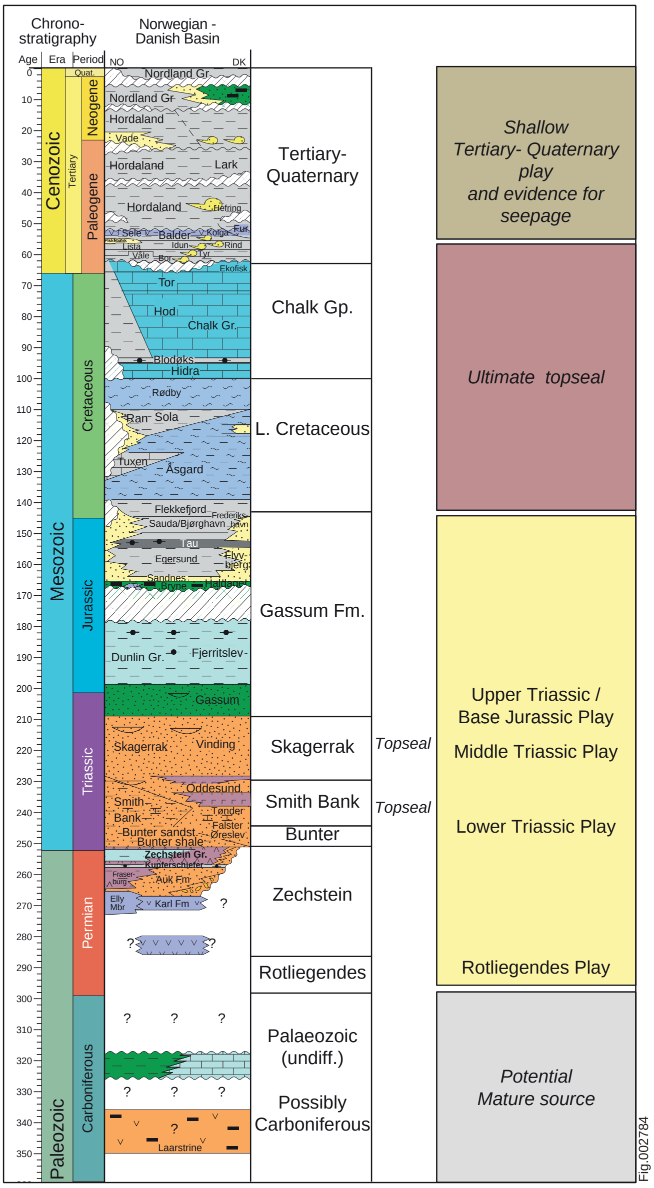


Figure 3.2 Litho Stratigrapic Column

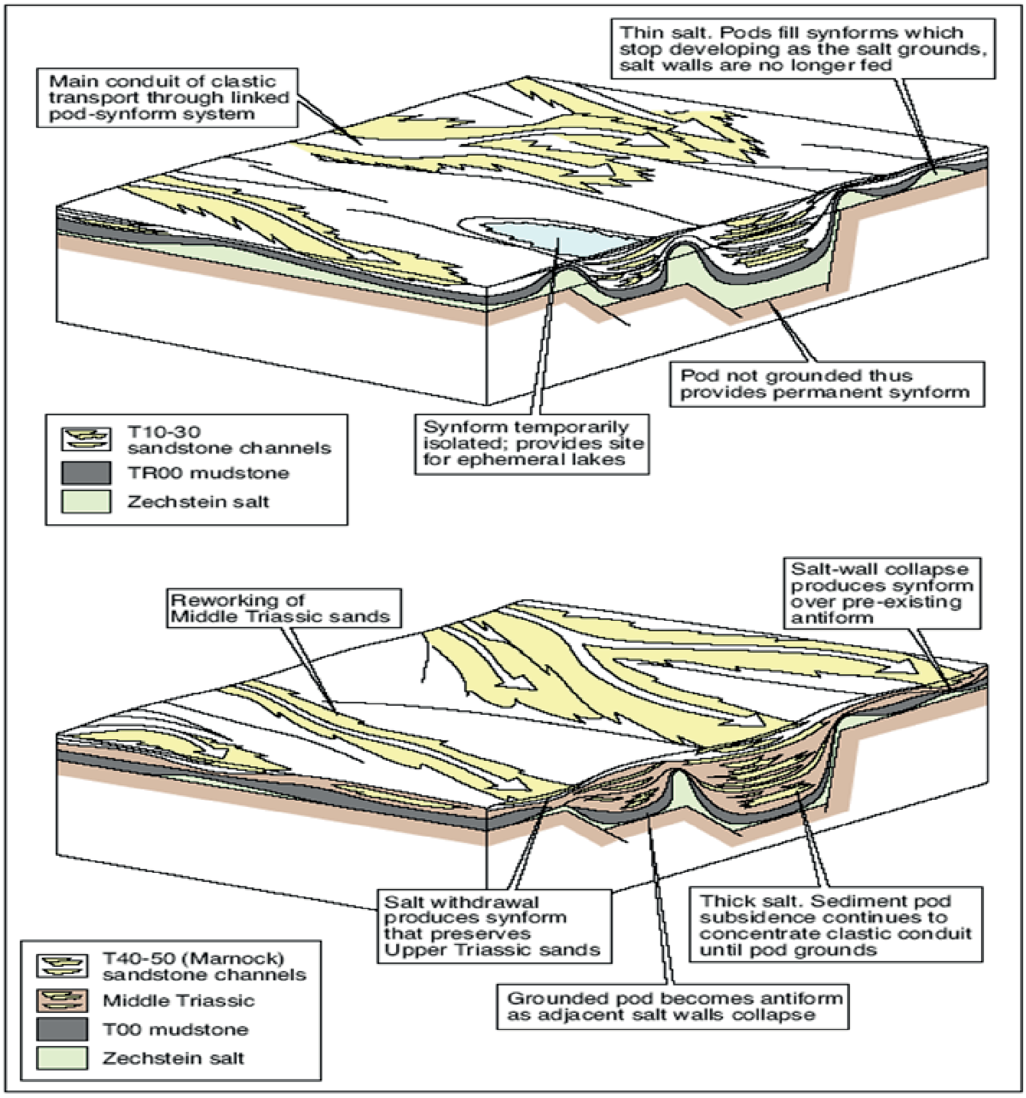


Figure 3.3 Triassic Pod Evolution

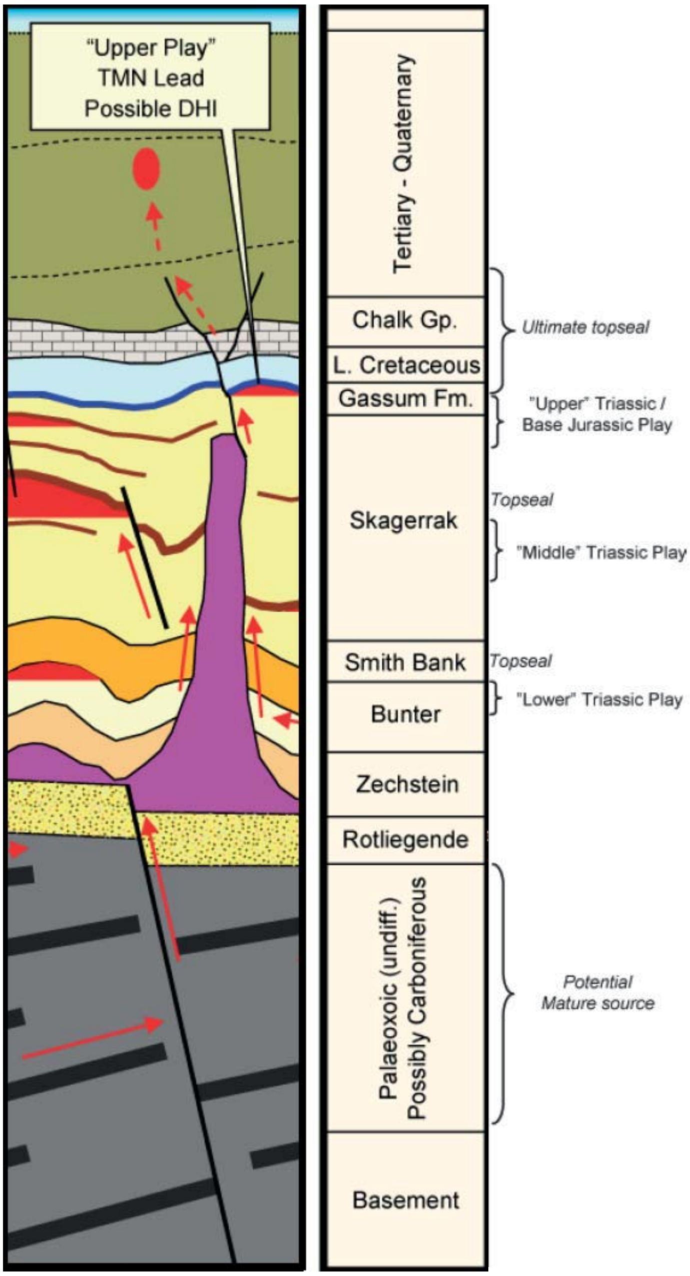


Figure 3.4 Play Summary Diagram

In the original prospect evaluation the source was expected to be of Carboniferous age. It is a working source in the Southern Permian Basin, but unproven in norwegian part of the Southern North Sea. This was evaluated as the main risk in the TMN prospect. A basin modelling study has been performed and concludes that the potential Carboniferous source, if present, is burned out at the time of trap generation (Figure 3.5). This has introduced an increased risk for the prospect related to source and migration.

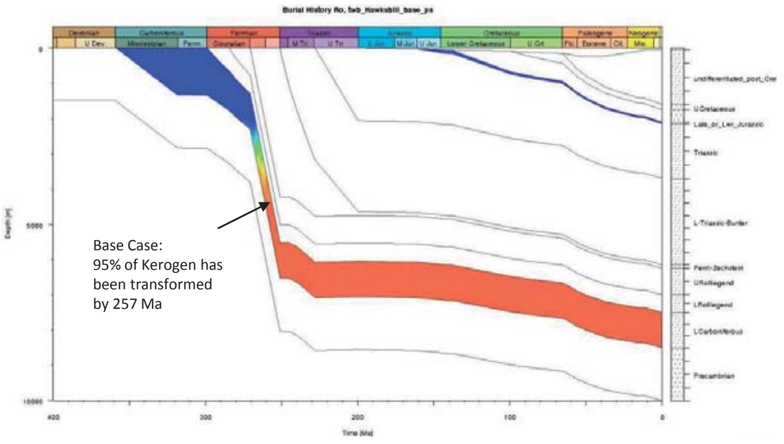
Despite a number of studies conducted ref section 2.3 Studies, which was intended to reduce exploration risk on play model, the opposite is seen; the risk has increased in particular with respect to source potential and timing of structures versus possible migration from a deeper source.

PROS

- Basin Opener in an underexplored sector of North Sea (Norway-Denmark)
- In the neighborhood of a world-class petroleum system (Southern Permian Basin)
- Surface Geochemical Survey suggests thermogenic HCs present at the seafloor
- Geophysical anomaly suggestive of gas-charged/flushed reservoir

CONS

- No proven source rock in the area
- Nearest wells are dry holes (~100km)
- No credible scenario effectively generates HCs to fill the traps at the time of trap formation or younger
- Only the most optimistic scenario allows for ANY HCs to be generated past the Critical Moment



- Under all scenarios, except for the Optimistic Case Kuperschieffer Marl scenario, the deeper source rocks have completed their transformation of kerogen before the trap is in place to capture the HCs.
- In all scenarios, the Upper Jurassic sediments are never buried deep enough, they never transform kerogen into HCs.

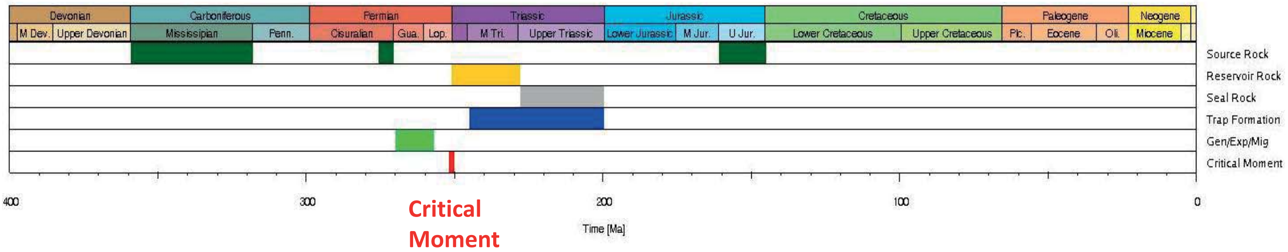


Figure 3.5 Integrated Charge Analysis Carboniferous Source Rock

4 Prospect Update

The Production licenses 402 and 402B are located far outside the proven petroleum province in the southern North Sea, with Harald Field in the Danish sector as the nearest field, 80km further south. The distinguishing feature of this area is that the normal source rock , the Draupne Formation, is not buried deep enough to produce hydrocarbons in this area. Any accumulation of hydrocarbons will thus be dependent on an older, Carboniferous aged source rock. In the Norwegian part of the North Sea a source rocks of Carboniferous age has not been proven.

Other wells in the Southern North Sea have been drilled with the objective to demonstrate commercial petroleum deposits originating from the corresponding strata. The dry well 8/10-3 in PL331 ("Megalodon") which was drilled in 2010, was intended to prove petroleum originating in the strata of Carboniferous age. It was considered that positive results from this well would affect the chance of success in PL402/402B in a positive direction.

In addition, a special feature that matters in the negative direction compared with well 8/10-3: The target for well 8/10-3 was to prove petroleum accumulated in the sandstone of Permian age , with rock cover consisting of a thick salt layers. In PL402/402B this salt layer deformed over geological time so that it does not form a continuous layer. Thus, the salt layer could act as a trap for hydrocarbons which are formed in the underlying strata of Carboniferous age. Based on basin modelling studies performed in the licences, this deformation probably occurred so early that the younger petroleum reservoirs (of Triassic and Jurassic age) was not formed before the source rocks of Carboniferous age had issued its hydrocarbon potential.

Amplitude versus off-set (AVO) studies have also been conducted and concluded that the main prospect, TMN, do not have direct hydrocarbon indicators (DHI's) as initially believed. An apparent high amplitude at top reservoir varies with structure and a seismic event that appears to be flat probably correspond to re-migration of salt, commonly observed in Gulf of Mexico Figure 4.1.

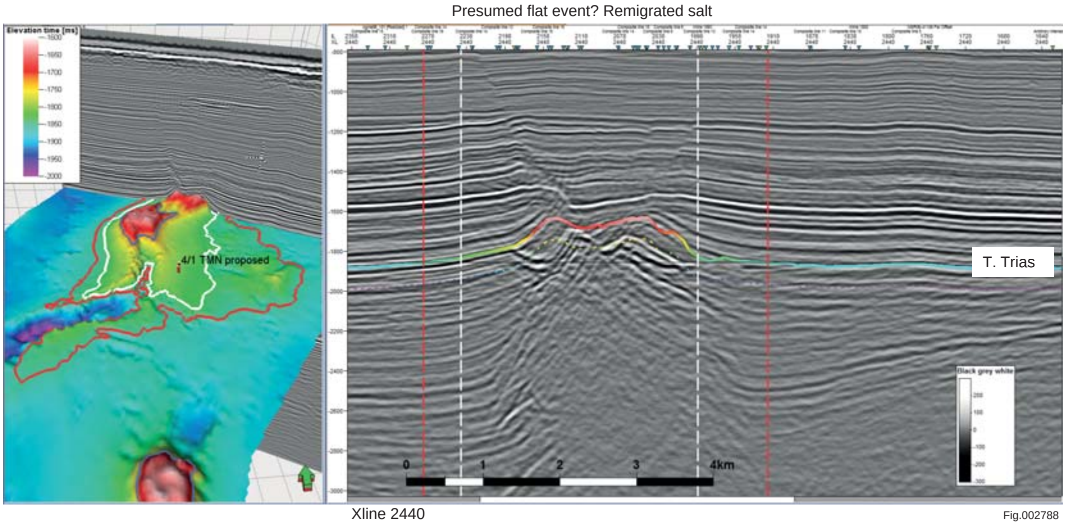


Figure 4.1 Seismic Amplitude Study. *Screening of 3D data does not give a clear support for DHI. High amplitude on top reservoir varies with structure (not consistent with closure). Suggested flat-spot is likely to be explained by re-migrated salt (very similar to analogues in Gulf Of Mexico)*

The probability of detecting a petroleum deposit is evaluated to be 11% for the TMN prospect. This is a considerable lower probability as compared to the APA application document from 2006. See NPD format prospect summary table from APA2006 (Table 4.1). Several other possibilities, called " leads ", were mapped out within the original licensed acreage, relinquished in 2009 and 2012. They have limited potential and are associated with higher risks.

Table 4.1 NPD format prospect summary table APA2006

Disc./Prosp. / lead name	Disc./P / L	Unrisked recoverable resources						Probability of discovery	Reservoir		Distance to infra-structure (km)
		Oil $10^6 Sm^3$			Gas $10^9 Sm^3$				Litho-/ Chrono-stratigraphic level	Reservoir depth (m MSL)	
		Low	Base	High	Low	Base	High				
TMN	P				3.34	6.80	11.30	0.35	Gassum/Skagerrak	2000	150
Flatback	P				1.17	12.00	31.00	0.15	Skagerrak	2570	150
Loggerhead	P				0.54	4.08	10.23	0.12	Skagerrak	2460	150
Ridley	P				0.28	2.63	6.74	0.11	Skagerrak	2580	150
Hawksbill	P				0.20	4.54	12.31	0.15	Skagerrak	3540	150
Loggerhead deep	P				0.48	6.86	18.23	0.12	Bunter Sandstone	3250	150

As a result of the the combined studies and re-evaluations performed in the area, the risk for several play elements has increased and it has not been possible to support an increased probability for discovery Table 4.2. It is at present not considered that futher studies can de-risk the prospect and alter the chance of success materially.

Table 4.2 Updated license prospect summary

Prospect	P90	P50	P10	Pmean	Risk
TMN	33	212	1332	499	0.11
Flatback	53	215	865	356	Lead
Loggerhead	46	162	575	247	Lead
Hawkbill	51	214	892	363	0.05
Ridley	52	161	497	225	Lead
Andrea	33	160	766	301	Lead
Flatback deep	55	299	1632	624	Lead
Loggerhead deep	162	483	1440	661	Lead
Total				**3276**	

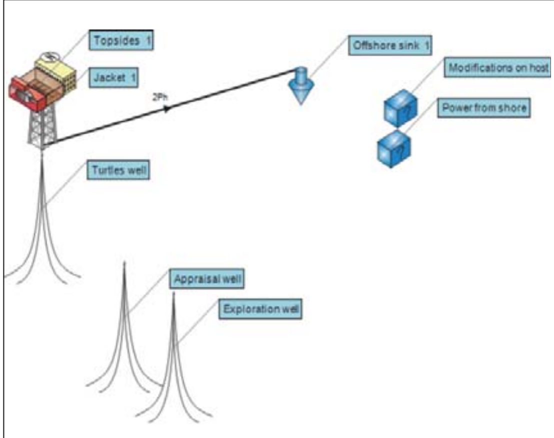
5 Technical Evaluations

The PL402 and PL402B are located in the southern part of the North Sea. The distance to shore is 150 km to Norway, 180 km to Denmark and the distance to existing facilities at Ekofisk is 120 km. Ekofisk infrastructure is evaluated as the most likely tie in point for resources in this area.

The development scenarios used for the economic calculations is done for the TMN prospect and are based on one exploration and one appraisal well, three gas producers, a well head platform (normally not manned), a gas pipeline to Ekofisk and first gas in 2024. The drilling is assumed to be carried out with the use of jack-up rig and the cost for each well is 407 MNOK for production wells and 431 MNOK for exploration and appraisal wells. The estimated cost for the development solution is estimated to be around 12 billion NOK, and 5.5 billion NOK in cumulative expected operating cost over the field life (nominal values). Without specific information about possible type of hydrocarbons and the physical conditions in any reservoir, these considerations are associated with considerable uncertainty. Compression is assumed to be included from day one.

Regardless of the size of a discovery, it must be expected to build a relatively well-equiped platform with process equipment. This is since the distance to the nearest facility with necessary process equipment is far away and it will be challenging to send non-processed well flow directly thereto. Water must be separated from the gas and the gas must also be compressed before transfer to a receiving platform. The operations will require substantial rotating equipment which will require frequent manpower for operation and maintenance.

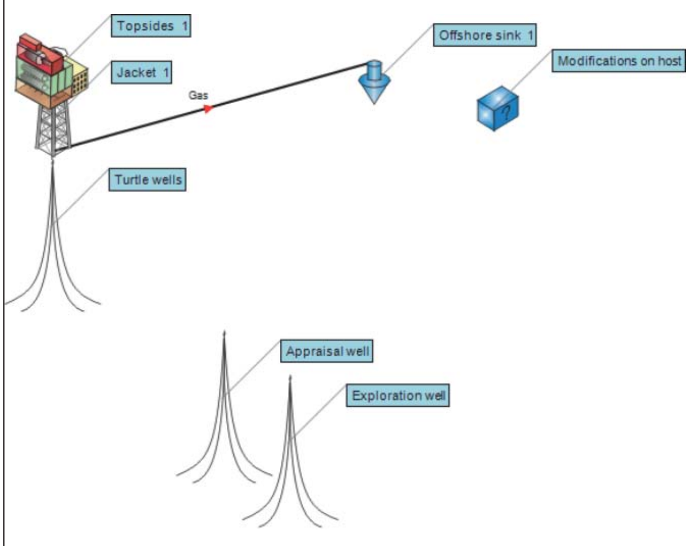
For the smallest resource estimate (P(90)) Figure 5.1 a similar development solution is assumed, however, with lower capacity requirements and thus lower overall cost. For the high resource estimate (P(10)) Figure 5.2, an independent development is assumed. The gas from the reservoir will be fully processed on the platform to reach sales specifications, and then be transported via existing gas export pipeline from Norway to the continent. It is here not taken into consideration downstream capacity constraints, which can be limited out of Ekofisk. The P(50) and P(mean) cases are shown inFigure 5.3 and Figure 5.4



Item	Cost [MMNOK]
Exploration & Appraisal	750
Pre-PDO	198
Wells	407
Platform	1476
Flowline & Power Cable	2288
Tie-in	520
Owner’s costs	346

Fig.002775

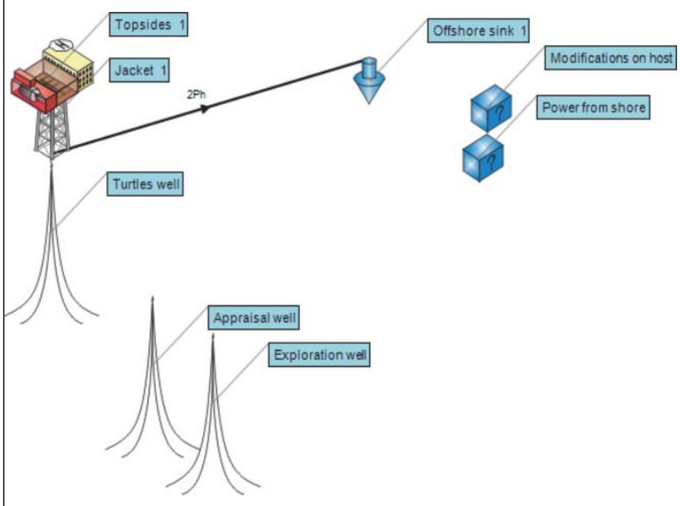
Figure 5.1 Development Solution TMN P(90) Case. *One production well. Wellhead platform with electrically powered gas compression.*
Power supply by cable from shore.Not normally manned installation. Living quarters for 15 persons. Wellstream export through 6" flowline.



Item	Cost [MMNOK]
Exploration & Appraisal	750
Pre-PDO	515
Wells	5291
Platform	8655
Pipeline	1893
Tie-in	520
Owner’s costs	772

Fig.002778

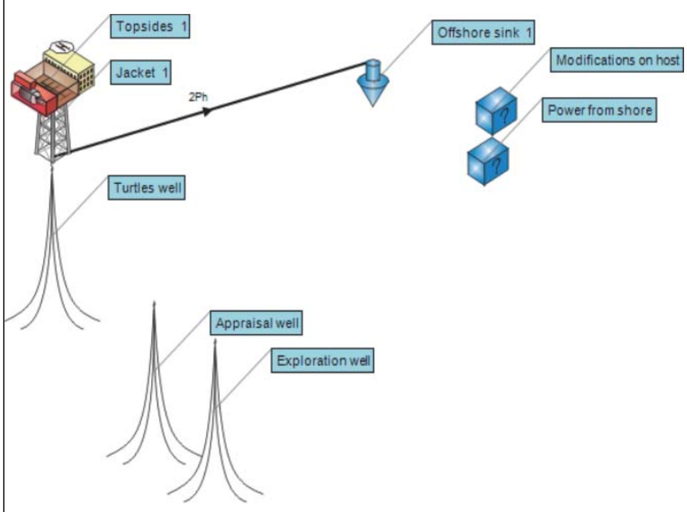
Figure 5.2 Development Solution TMN P(10) Case. *13 production wells. Production-Quarters platform with gas compression. Living quarters for 37 persons. Gas export through 28" pipeline.*



Item	Cost [MMNOK]
Exploration & Appraisal	750
Pre-PDO	267
Wells	1221
Platform	1910
Flowline & Power Cable	3401
Tie-in	520
Owner’s costs	468

Fig.002776

Figure 5.3 Development Solution TMN P(50) Case. *Three production wells. Wellhead platform with electrically powered gas compression.*
Power supply by cable from shore. Not normally manned installation. Living quarters for 15 persons. Wellstream export through 12" flowline.



Item	Cost [MMNOK]
Exploration & Appraisal	750
Pre-PDO	330
Wells	2035
Platform	2719
Flowline & Power Cable	3913
Tie-in	520
Owner's costs	578

Fig.002777

Figure 5.4 Development Solution TMN P(mean) Case. *Five production wells. Wellhead platform with electrically powered gas compression. Power supply by cable from shore. Not normally manned installation. Living quarters for 15 persons. Wellstream export through 18" flowline.*

The subsurface assumptions for the different volume cases and development scenarios are summarised in Table 5.1

Table 5.1 Subsurface Metrics

Case	Technically Recoverable [bcf]	Production wells (No off)	Peak rate [mmscfd]	Production Wells	Fac & Infrastruct. (MMNOK	Development Capex Total (MMNOK)*
P90	31	1	14,6	407	4 828	5 235
P50	188	3	94,1	1221	6 566	7 787
Pmean	427	5	221,5	2035	8 060	10 095
P10	1141	13	591,3	5291	12 355	17 646

TMN - summary tables (Success case): Table 5.2 show the metric calculations.

Table 5.2 TMN - summary tables (Success case)

TMN Gross, Success, Nominal, mmNOK	P90	P50	Pmean	P10
Gas bcf	25.9	173.2	427.6	1,122.5
Total Revenue	2,049	14,589	36,425	88,923
Total Capex	8,859	12,260	15,679	26,031
-abandonment	1,794	2,137	2,657	4,248
Total Opex	2,100	5,429	9,903	23,668
Pre-Tax NPV10	-3,587	-2,528	607	8,985
Government Take	-7,943	-3,871	6,571	27,394
Post-Tax NPV10	**-988**	**-750**	**25**	**2,053**
IRR	**-6 %**	**3 %**	**10 %**	**18 %**

*Pre-Tax NPV8 in MMNOK: P90: -4 218, P50: -2 707, Pmean: +1 479, P10: +12 174

The EMV for TMN prospect for P10, P50, P90: Figure 5.5 in total is negative. There is 3-5% chance to discover more then P50 volumes. As presented it will only be the P10 volumes which is obtaining a positive NPV post tax.

			Unrisked outcomes		Risked Outcomes		
			Reserves (bcf)	NPV10 Nominal	P(O)	Reserves (bcf)	NPV10 Nominal
11%	25%	**P10**	**1,122**	2,053	**2.8%**	31	56
	50%	**P50**	**173**	-750	**5.5%**	10	-41
	25%	**P90**	**26**	-988	**2.8%**	1	-27
89%			**0**	-95	**89.0%**	0	-85
				Risked Total	**100%**	**41**	**-97**

Figure 5.5 TMN - EMV of P10, P50, P90

6 Conclusions

The license partners in PL 402/402B consider that the technical work done is comprehensive since the time of license award and that the geological and commercial risk has increased. The main risk elements is associated with the presence of a working petroleum system and timing of potential migration versus timing of forming of the structures.

The PL402/402B area is in a remote location without any infrastructure which drives the threshold volumes up for an economic scenario.

It is expected that any hydrocarbons found within the production licenses acreage will be in the gas phase and this forms the basis for resource estimates and development solutions that is used in the financial calculations.

The economic analysis shows that the resource base must be in the range 430bcf (12.2mrd Sm^3) with gas in order to achieve 0 million net present value (at 10% discount). The probability of detecting this volume with an exploration program is estimeated to <5%.

It would not be economically viable to develop a field based on 0 value. Therefore, proven resources to be closer to what is set as the P(10) estimate equal 1100bcf / 31.5 Billion M3 will be potentially economically. The present value of this development scenario is estimated to be 2 billion (after tax) and provide an internal rate of return (IRR) of 18%. The probability of detecting this resource estimate is <2.5 %.

Since 2010, Talisman has invited other companies to participate in the license without sucsess, indicating that the current evaluation also represent the industry view.

The recommendation to relinquish is based on this evaluation and concludes that there are no viable exploration targets within the PL402/402B acreage. The partnership has therefore agreed to relinquish the entire licence area.