Relinquishment report

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1 Summary of Licence History

The PL679S (Fig. 1.1) licence was awarded following the 2012 APA licencing round, to BG Norge AS (60% and operator) and E.ON E&P Norge AS (40%), with an effective date of 8th February 2013.

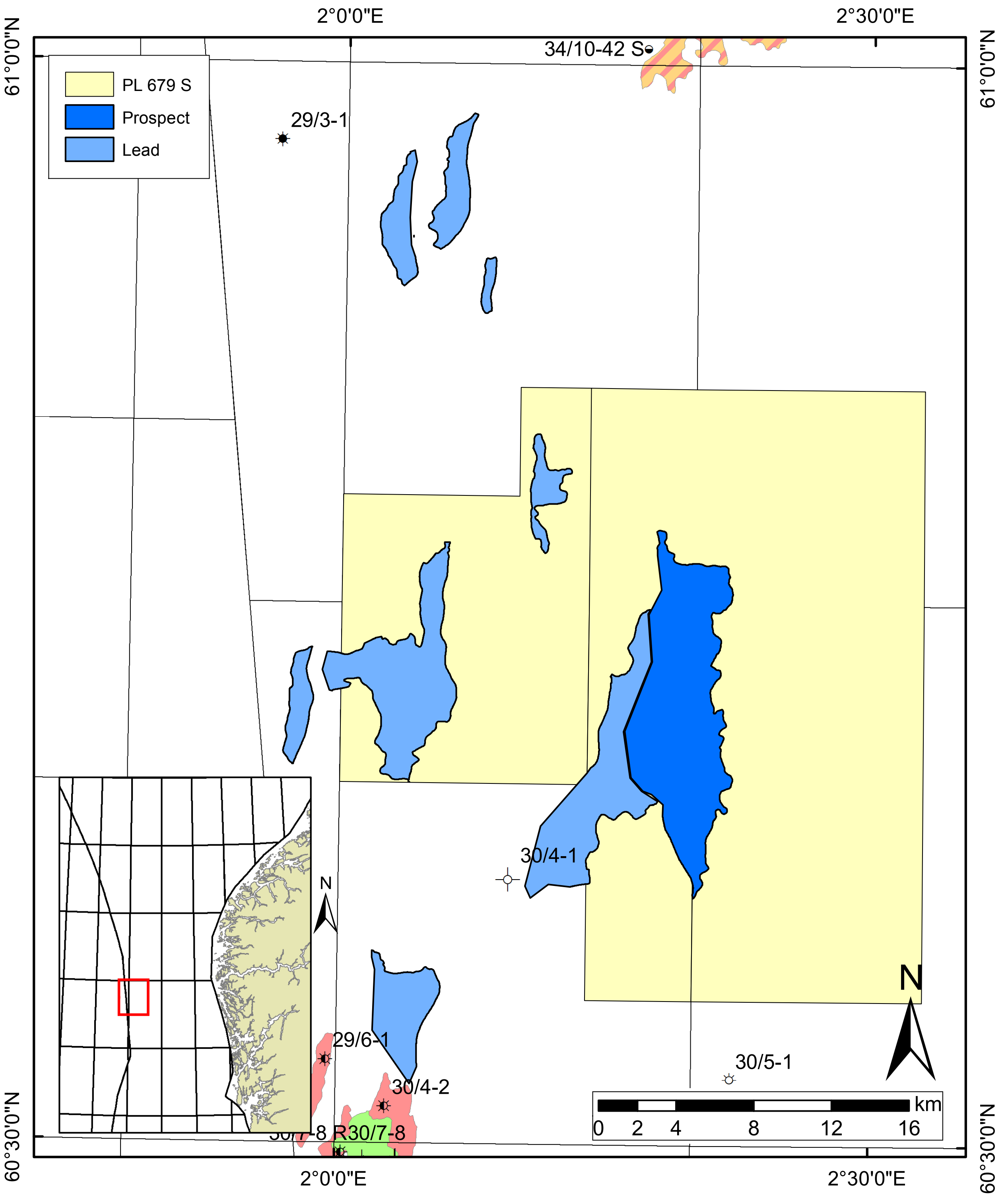


Fig. 1.1 PL679S location map.

The initial work program was:

- Reprocess existing 3D seismic data within the awarded area.
- Perform relevant geological and geophysical studies in order to evaluate the requirement for collection of new seismic or other data.
- Make a Drill-or-Drop decision (DoD) within 1 year of the licence award, before the 8th February 2014 Drill-or-Drop date (extension of Drill-or-Drop date granted until 8th August 2014).

The licence covers part of blocks 30/1, 30/2, 30/4, 30/5. Blocks 30/1 and 30/4 have a stratigraphic split, with PL679S being restricted to below the Top Cretaceous in those areas.

The voting rule for the licence is two parties and more than 50%. This requires each decision to be unanimous given the set-up of the licence. Given that there was a 1 year period for all G&G studies, including seismic reprocessing, licence meetings were held quarterly (rather than the customary six monthly) to discuss the seismic reprocessing and the subsurface evaluation.

The partner group has purchased and reprocessed the over the licence area through the multiclient PGS NNS MegaSurvey Plus. The NX10M02 survey had the benefit of not only covering the licence area but also many of the additional Brent structures in the basin, which were also of interest to the partner group. The initial fast-track time migrated seismic volume was available in July 2013 (PGS MegaSurvey Plus Phase 1) and the PreSTM volume was delivered in September 2013. Due to the later-than-expected delivery of the final volume (resulting from civil unrest in Cairo where the data was reprocessed), a six month extension to the Drill-or-Drop date was requested. This enabled the Partnership to carry out a full interpretation of the final seismic volume and to close out the technical work program. This extension was subsequently granted by the Ministry, taking the Drill-or-Drop milestone to the 8th August 2014.

Remapping on the new seismic dataset combined with various depth conversion methods has showed the main prospect Tingen to have markedly reduced GRV compared to the original evaluation of the prospect during the APA 2012. In addition, it is now thought the structure cannot fill to a significant extent prior to leakage through the top seal and/or the prospect-bounding faults. Reservoir property modelling has shown that the critical risk, reservoir effectiveness remains the biggest technical challenge, and the licence group concluded that the Brent Group reservoir cannot flow at commercial rates at the depths of Tingen prospect.

The secondary plays in the licence area comprising Upper Jurassic and Lower Cretaceous turbidite plays have been evaluated. Reservoir presence for the secondary plays remains the critical risk and the licence group did not find any material leads.

The Licencees therefore made the unanimous decision to relinquish the PL679S licence at the final Drill or Drop date on the 8th August 2014 following the conclusion of an extensive licence work program.

2 Database

2.1 Well and Seismic database

WELL DATABASE

The common well database that was established for the PL679S evaluation consisted of the released wells listed in the Table 2.1.

Table 2.1 Well database utilized for the PL679S evaluation.

Well	Year reached TD	Result	Petrophysical evaluation	Seismic well tie
3/10b-1 (UK)	1984	GAS SHOWS		yes
3/15-4 (UK)	1978	GAS SHOWS		yes
29/3-1	1986	OIL/GAS		yes
29/6-1	1982	GAS/CONDENSATE	yes	
30/2-1	1982	GAS/CONDENSATE	yes	yes
30/4-1	1979	DRY	yes	yes
30/4-2	1980	GAS/CONDENSATE	yes	yes
30/5-1	1972	GAS SHOWS		yes
30/5-2	1996	OIL/GAS	yes	
30/5-3 S	2009	GAS		yes
30/8-1 S	1995	GAS/CONDENSATE		yes
30/8-4 S	2009	OIL	yes	yes
30/9-14	1993	OIL/GAS	yes	
30/7-7	1979	GAS SHOWS		yes
30/10-6	1992	GAS	yes	yes
34/10-8	1980	OIL	yes	
34/10-16	1983	OIL/GAS	yes	
34/10-23	1985	GAS	yes	
34/10-42 S	1999	SHOWS	yes	yes

For the petrophysical evaluation a shortlist of the above key Brent wells was created reflecting a range of geology, phase type and reservoir conditions. The 30/4-1 well targeted a Brent structure in the centre of the basin and is the key well of the subsurface evaluation. As mentioned later in this document a fluid inclusion study was carried out on cuttings from this well. Additional wells were included to carry out seismic well ties to constrain the time interpretation and velocity field for depth conversion.

SEISMIC DATABASE

During the APA 2012 licencing round, the PGS MC3D MegaSurvey 3D survey was used to evaluate the prospectivity in the PL679S area. Following award of the licence in 2013 the licence group purchased the merged NX1002 3D PreSTM survey which was merge of the long offset NX0901, NX0902 and NX0803 3D surveys (Fig. 2.1).

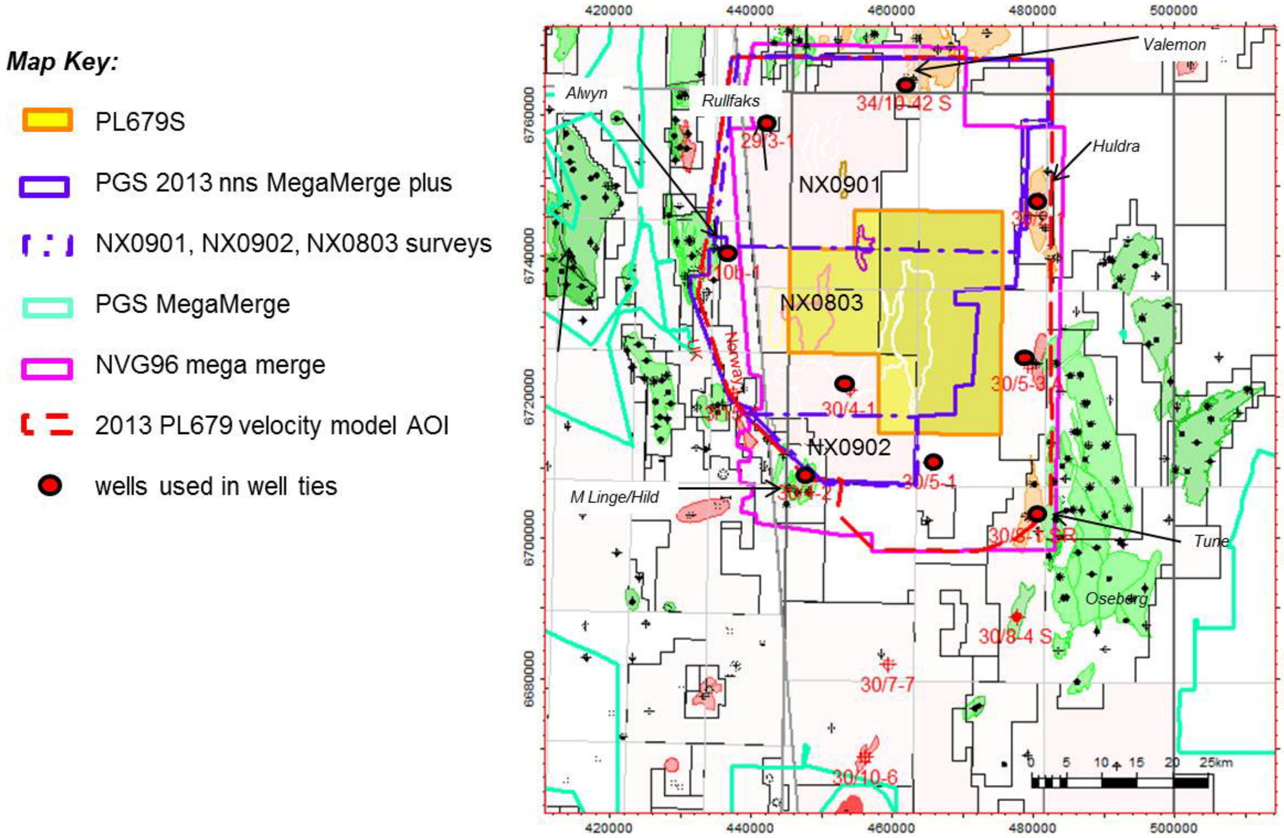


Fig. 2.1 3D seismic common database for PL679S.

The licence group also purchased the multiclient PGS MegaSurvey Plus 3D survey which is a PreSTM reprocessed dataset which includes reprocessing of the merged NX10M02 3D survey carried out in 2013. The 2013 PGS MegaSurvey Plus Kirschoff PreSTM focused on improving data quality through improved velocity model building, noise and multiple attenuation and amplitude balancing. The final PreSTM was planned for a June 2013 delivery but delivery of the final full stack data was delayed until September 2013 due to civil unrest in Cairo where PGS were reprocessing the dataset. Although the MegaSurvey PreSTM product is a multiclient dataset, the licence operator attended processing QC meetings and took part in and guided the decision making process during the processing. The 2013 PGS MegaSurvey Plus PreSTM shows an improvement in data quality over previous datasets. The MegaSurvey Plus PreSTM full stack 3D volume was used as the main volume for the PL679S seismic interpretation. An additional version of the final full stack was output with an additional deconvolution applied which removed residual multiple immediately below the Base Cretaceous unconformity. The version of the final full stack with the additional deconvolution applied improves imaging immediately under the BCU but reduces the strength of the Top Brent reflector. The final full stack volume was used to map the Top Brent Group and the final full stack volume with additional deconvolution was used to screen for leads leads in the Kimmeridge/Draupne Formation. Screening for secondary prospectivity was carried out using difference volumes created between the near and far stack but no prospectivity was identified. Seismic volumes available for the PL679S seismic interpretation are listed in the below Table 2.2

Table 2.2 Seismic database available for the PL679S evaluation.

Survey Name	Volume name	Comments
mc3d_nns MegaSurvey Plus	mc3d_nns_Post_Processed_PSTM_post_Decon_Stack	2013 final PrSTM stack with an additional deconvolution
	mc3d_nns_Post_processed_PSTM_Stack	2013 final stack without additional deconvolution
	mc3d_nns_Post_Processed_Migration_Ve	migration velocity
	mc3d_nns_Post_processed_Stacking_Vel	final stack stacking velocity
	mc3d_nns_near_angle_pstm_stack	near angle stack
	mc3d_nns_mid_angle_pstm_stack	mid angle stack
	mc3d_nns_far_angle_pstm_stack	far angle stack
	mc3d_nns_ultra_far_angle_pstm_stack	ultra far angle stack
nx 10m02	nx10m01 final_mig full offset	2010 merged dataset of NX0902, NX0901 & NX0903, prestm procesed by Geotrace
mcd3-north-sea-mega NVG	mc3d-north-sea-mega NVG	MegaMerge full stack 3D volume. APA2012 interp based on this volume
nvg96r01	nvg96r01 final_mig	2001 reprocessed short offset 3D data
nvg96_merg	nvg96_merg final_mig	1996 prestm

3 Review of Geological and Geophysical Framework

The subsurface evaluation of the PL679S licence was primarily focused on the Middle Jurassic, Brent Group. The potential for Upper Jurassic - Lower Cretaceous age turbidite reservoirs was considered, however seismic data were not able to de-risk these plays.

The main change to the subsurface interpretation, during the licence period, was derived from the final processing of the NX10M02 3D seismic data, which showed that the Gross Rock Volume (GRV) of the main prospect, Tingen, had reduced significantly. In addition, geological studies show that the prospect is unlikley to be filled-to-spill. The most likely hydrocarbon column is therefore smaller than expected. The main risk element of the prospect/play is reservoir effectiveness. Geological studies have shown that this risk has increased, with the prognosed permeability being unlikely to deliver a commerical flow of hydocarbons.

3.1 Reservoir

The Middle Jurassic sandstones of Brent Group was evaluated as the main potential reservoir interval within the PL 679S licence area. The Brent Group comprises five lithostratigrafic units: Broom, Rannoch, Etive, Ness and Tarbet Formations.

The main reservoir intervals in the Brent Group are represented by the upper shoreface sandstones of the Tarbet Formation and the coastal plain facies of the Ness Formation.

GDE maps created by the licence group shows the PL679S area to be dominated by upper shoreface facies, indicating that the reservoir presence is not a risk in the PL679S area (Fig. 3.1).

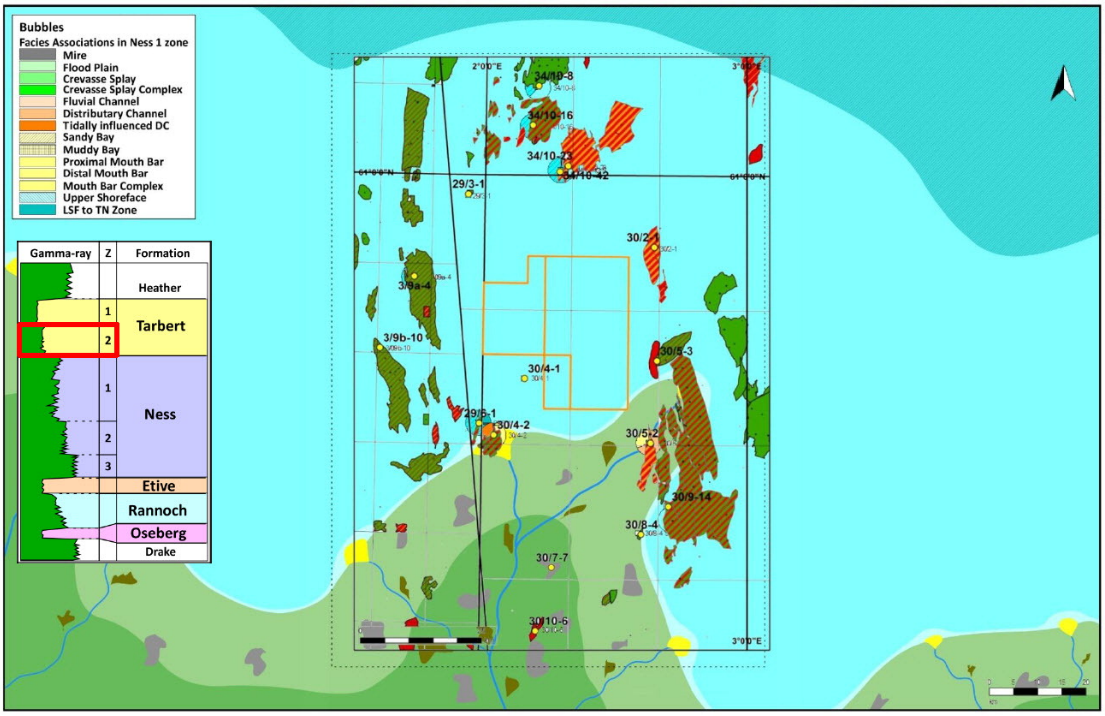


Fig. 3.1 Tarbert 2 GDE. GDE for Tarbert 2 sequence showing geology over PL679 S to be dominated by Upper Shoreface sands

Fig. 3.2 shows the character of the Brent Group package from the western flank of the basin at UK well 3/09a-4 to the key deep well 30/4-1. This correlation panel also shows the expected depositional environment in the Brent Group with the uppermost Tarbert Formation being dominated by shoreface sands and the Ness Formation being dominated by coastal plain facies in the Tingen license area.

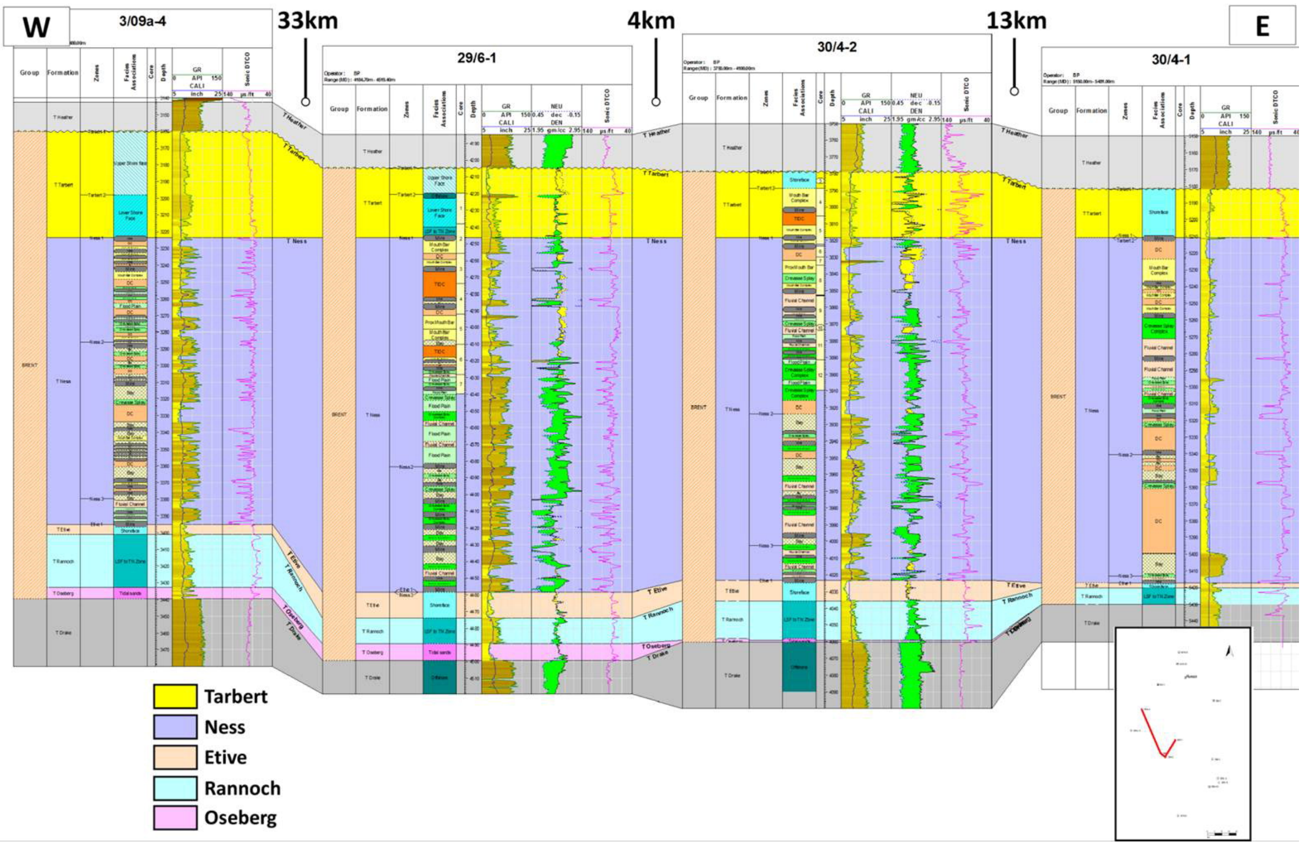


Fig. 3.2 Brent W-E correlation. Correlation of Brent Group from western flank of basin to key well 30/4-1. Depositional environments are shown.

The top Brent Group pick on the reprocessed seismic dataset is a clear hard kick and well tied to the key wells (Fig. 3.3), including those in the correlation panel in Fig. 3.2. The Brent Group in the licence is expected to be thick as the closest offset well contains a Brent section in excess of 200m.

A Touchstone model (a commercial diagenetic modellingpackage) was produced in order to understand the reservoir quality within Tingen and surrounding prospects. A total of six wells were included on this study plus two contingency wells. The cores were sampled at the NPD corestore. A total of 75 new thin sections were analyzed, including XRD and SEM. A Touchstone specific petrographic study was conducted by Robertson. The diagenetic study showed that the main controls on the reservoir proprieties are: compaction reducing primary porosity, dissolution of labile grains creating secondary porosity, precipitation of abundant authigenic clays converting macroporosity into microporosity and precipitation of authigenic cements. The Touchstone model predicts a significant reduction of porosity and permeability with increase of depth (Fig. 3.4).

Petrophysical analysis was carried out on a total of 12 wells (Table 2.1) in order to define the reservoir proprieties for volumetric input. After the petrophysical analyses, the mode net to gross ratio was

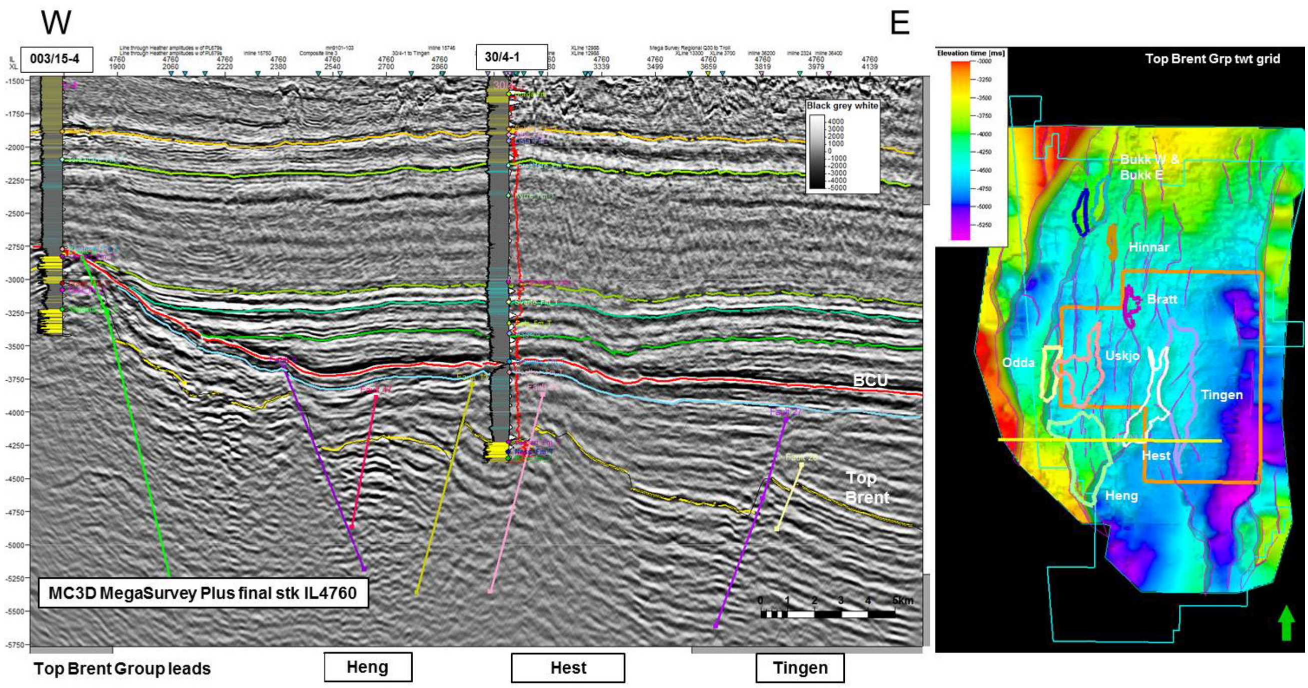


Fig. 3.3 Seismic section across Tingen prospect.

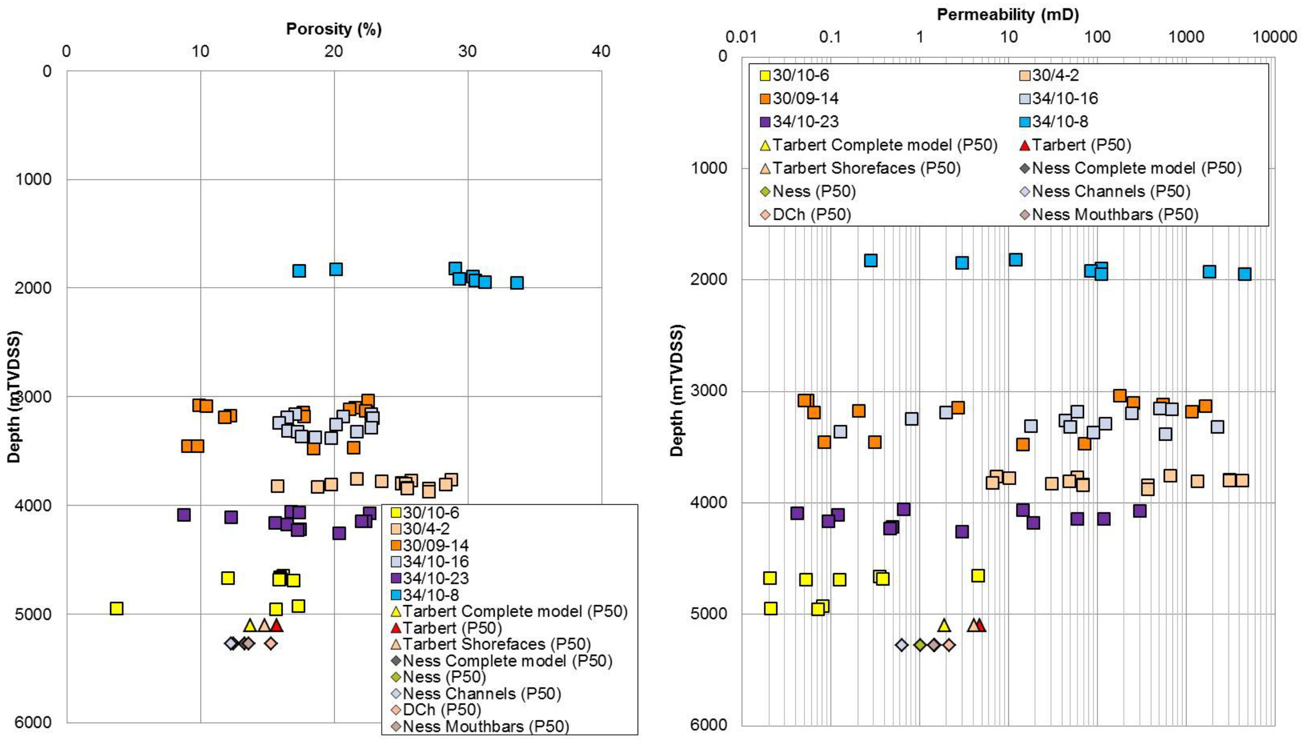


Fig. 3.4 Depth vs. porosity and permeability plots. *Plots showing the results for the wells included on the model and the P50 predictions on Tingen depth, at 5101m TVDss.*

reduced compared with the assumptions made in the APA 2012 from 0.6 to 0.4, using 10.5% porosity cut-off. Porosity vs. permeability plots of the offset wells used in this petrophysical are shown in the Fig. 3.5

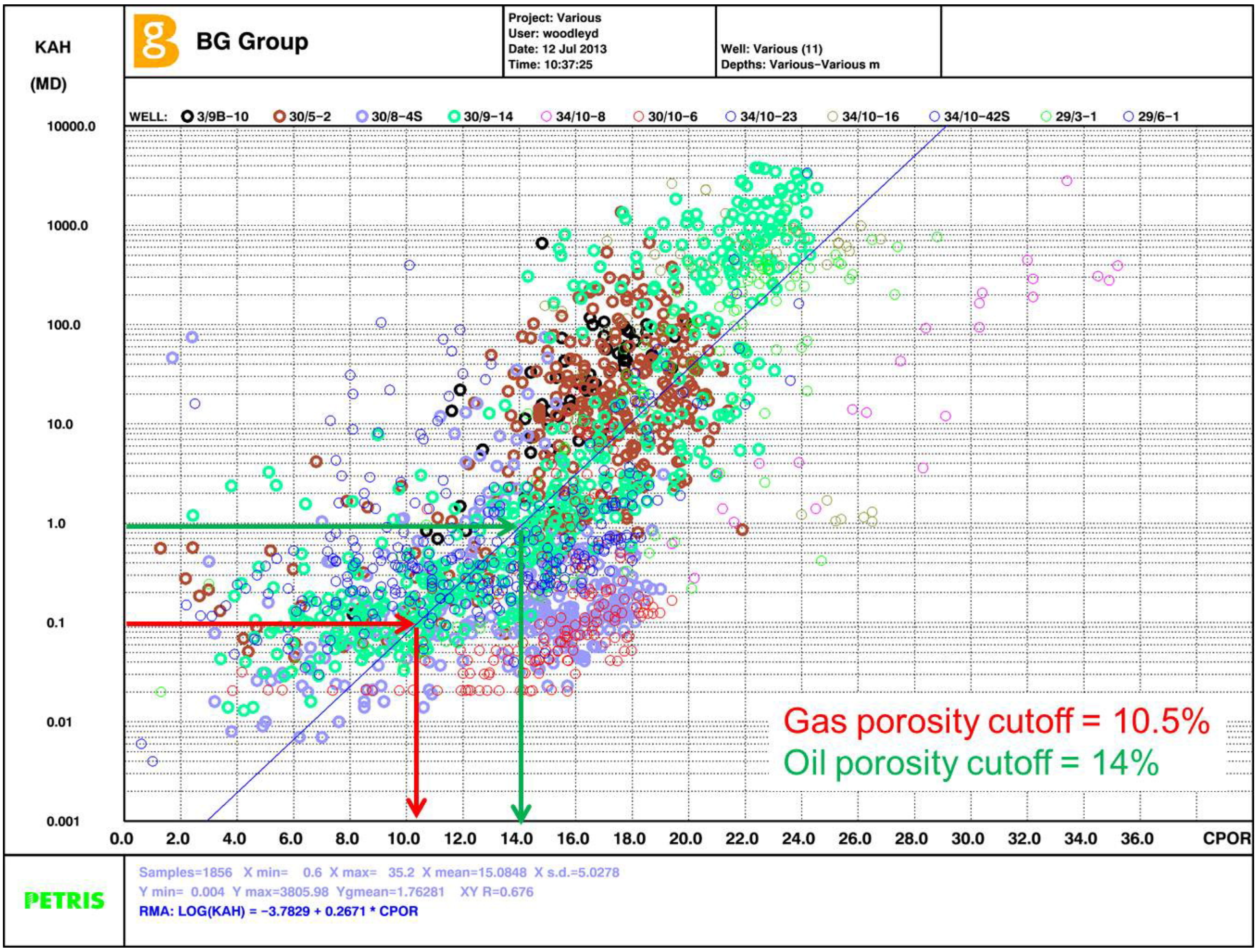


Fig. 3.5 Poro-Perm plots of offset wells used on the petrophysical analysis.

The reduction of the net to gross caused a significant negative impact on the prospect volumes.

Whilst reservoir presence is not a risk for the evaluation of Tingen, reservoir effectiveness is considered to be the main risk based on the studies conducted for this area.

3.2 Trap

Trap Configuration

During the APA 2012, Tingen (and the other Brent HPHT structures in Quad 30) were mapped on the PGS MegaSurvey, a post stack merge of varying vintage surveys. The quality of the data at key reflectors at 4-5 seconds TWT was deemed sufficient for the mapping of the Top Brent Group structures and encouraged the licence group that there was potential to hold significant volumes. However, it was recognised that data quality could be improved to reduce the uncertainty on GRV and the risk on trap configuration. A Top Brent Group depth map from the APA 2012 licence document is shown in Fig. 3.6. The Operator mapped a break in the main N-S prospect bounding fault, concluding that there was an inherent risk to trap integrity at this point. There was uncertainty as to the closing contour of the prospect.

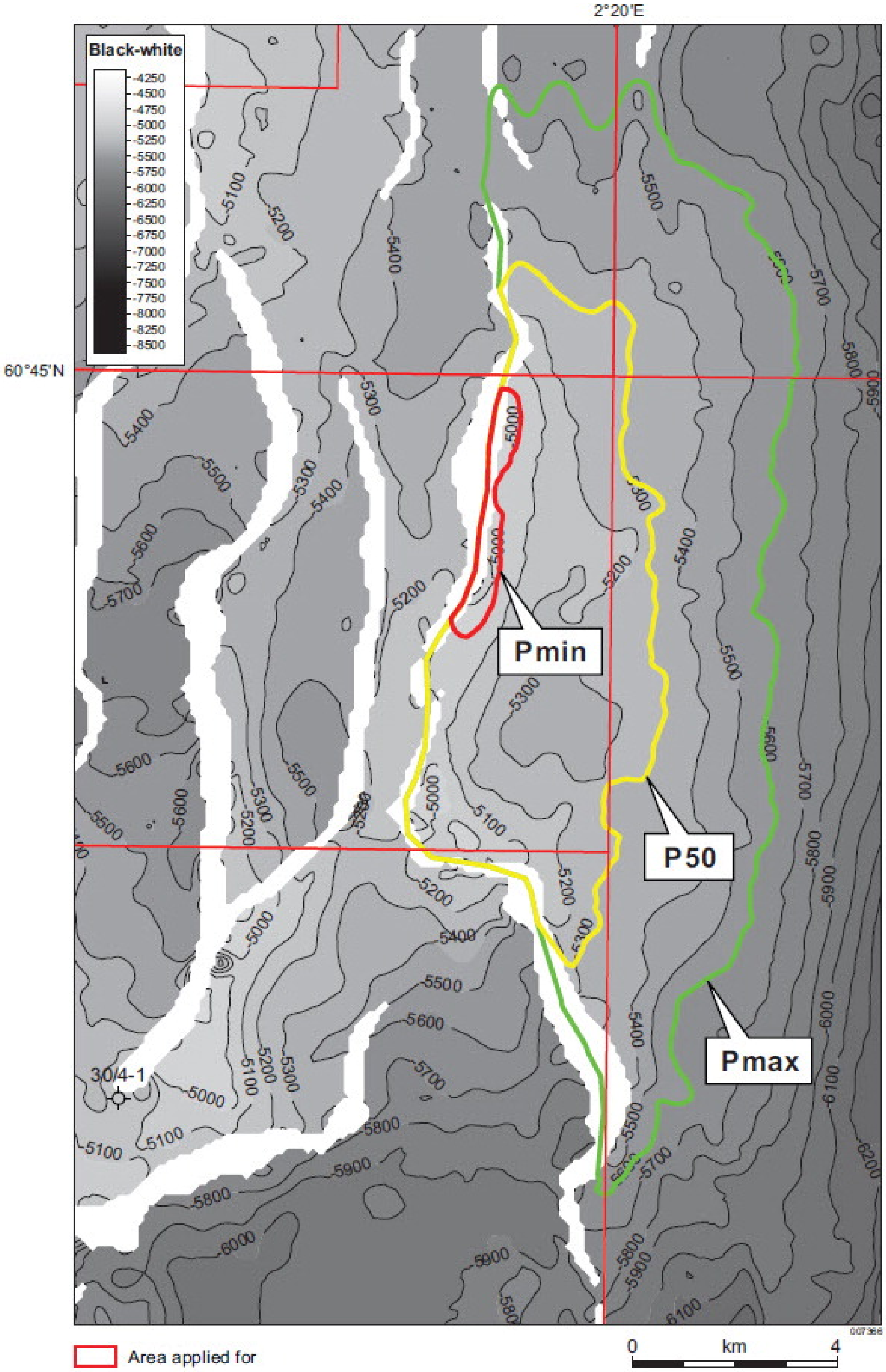


Fig. 3.6 Original Top Brent Group Depth Map. Tingen structure as mapped for APA 2012 on PGS MegaSurvey. Contact range has normal distribution from crest down to spill.

Re-mapping of the trap made a significant change to the interpretation of Tingen during the licence period. The newly reprocessed 3D seismic PGS MegaSurvey Plus (a pre-stack time migration reprocessing of the NX10M02 3D survey) was completed in Q3 2013 and greatly improved the imaging of the key reflectors, specifically the Top Brent Group and the BCU reflectors across the licence. Where 2013 MegaSurvey Plus volume does not cover the eastern part of the PL679S licence the seismic interpretation was carried out on the original PGS MegaSurvey final stack volume.

The Top Brent is clearly imaged on the new 2013 MegaSurvey PreSTM and is picked on a seismic peak, representing an increase in acoustic impedance from the overlying lower density Heather Formation into the higher density well cemented sands of the Brent Group.

The 2013 Top Brent time interpretation shows the flanks of the Top Brent Tingen prospect to be slightly steeper and deeper than was previously interpreted (2012 time and depth interpretations). The crest of the prospect has been mapped at 5250m, deeper than the crest mapped during the application evaluation at 4900m . The 2013 mapping shows the Top Brent Group in the Central part of the Tingen structure to have very little offset between the hanging-wall and footwall of the main N-S trending fault. This is due to Cretaceous inversion along the main bounding fault (the effects of which can also be seen in small folds affecting the shallower BCU). Lack of demonstrable fault offset leads to increased fault seal risk along this fault.

On the new (2013) reprocessed data, issues remain with seismic imaging, particularly across the crest of Tingen (Fig. 3.7). This could be as a result of the presence of gas escaping from the structure or simply a dissipation of signal strength resulting from overburden complexities, such as Oligocene-age injectites.

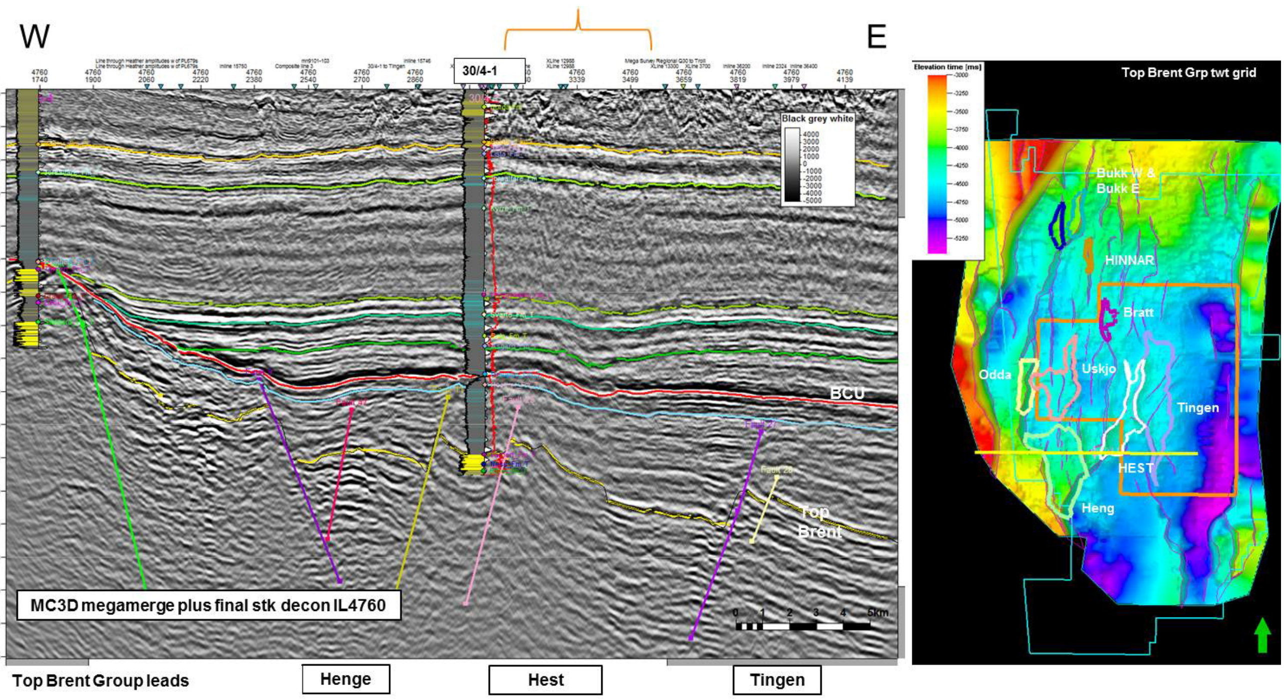


Fig. 3.7 Seismic line across Tingen prospect. *Seismic shows poor imaging above Tingen crest.*

The 2012 pre APA interpretation was depth converted using the Aker Solution High Quality regional velocity cube. A key part of the re-evaluation of Tingen was to re-evaluate the depth conversion methodology. Synthetic well ties were carried out at 12 wells around the PL679S licence area and used to constrain the time interpretations, velocity analysis and final velocity models. These velocity models tied not only the 30/4-1 well (adjacent to the licence area) but also all other available wells covered by the 2013, PGS MegaSurvey Plus, 3D final full stack volume. Layer cake depth conversion models using both well and seismic staking velocities were created to understand the depth conversion uncertainty (Fig. 3.8). A base case 4-layer depth conversion gridding well interval velocities (Fig. 3.9) was used for input to volumetrics. Depth conversion uncertainty is addressed in the final prospect evaluation by application of a low and high case GRV factor factor in stochastic prospect volumetric analysis.

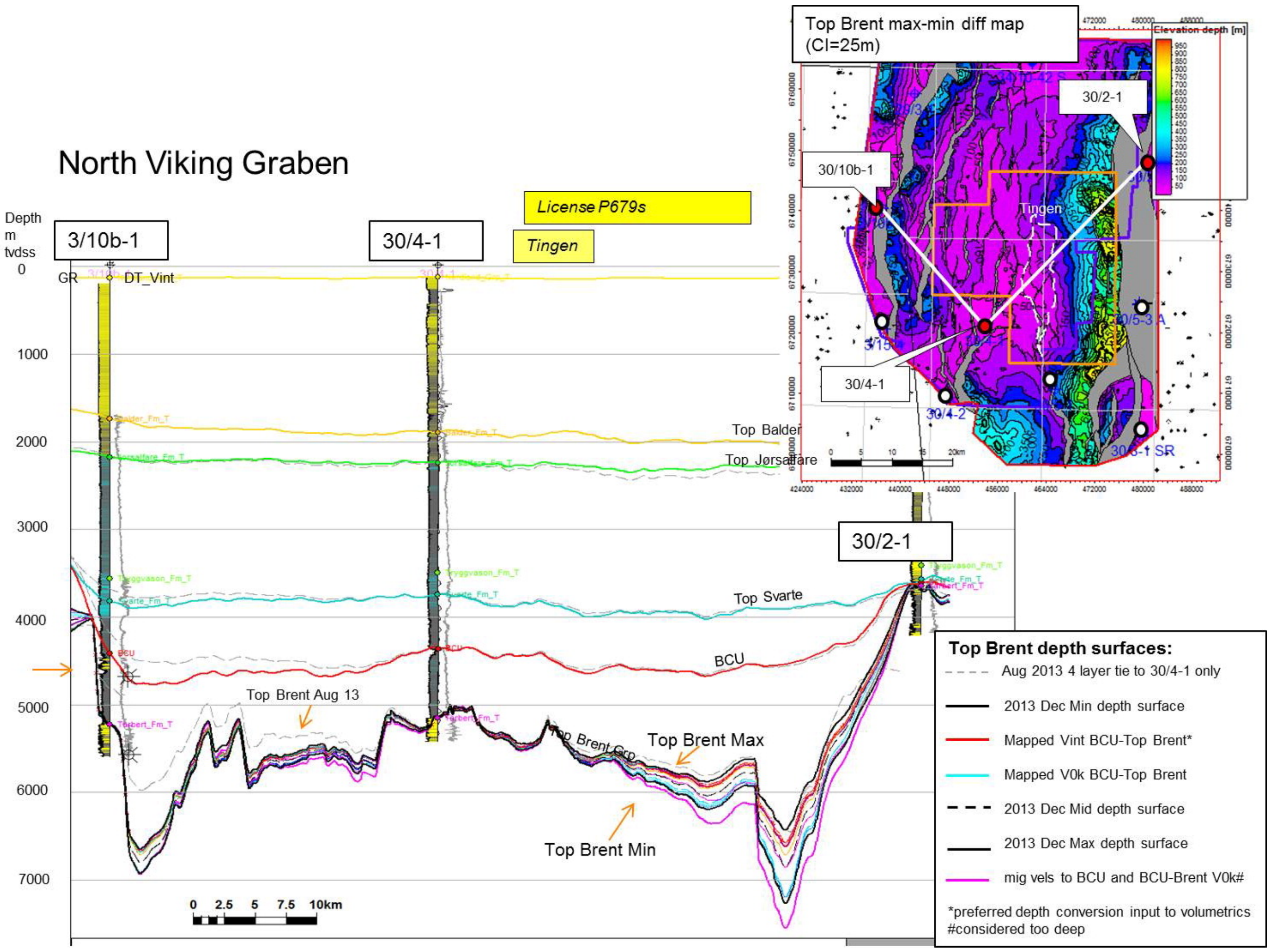


Fig. 3.8 PL679S depth conversion of Top Brent.

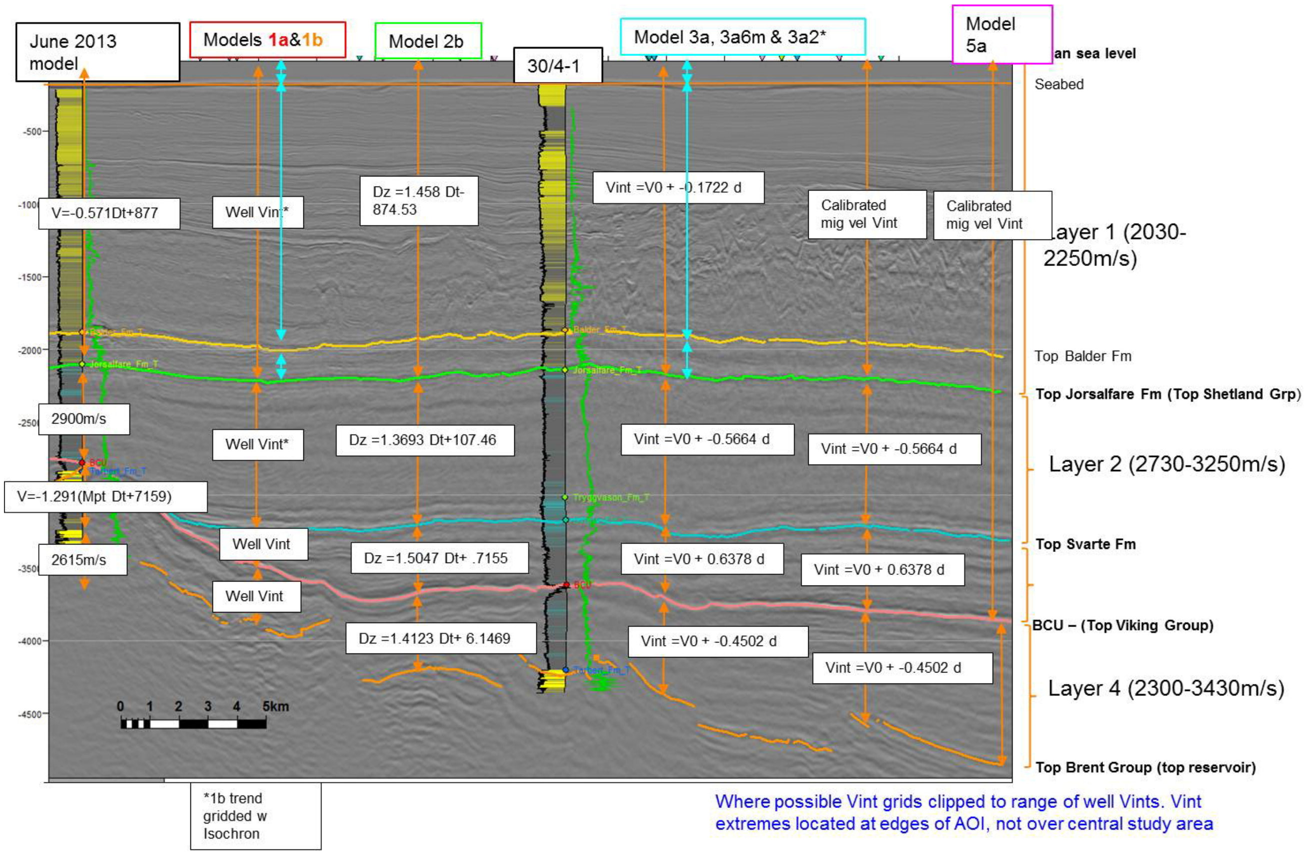


Fig. 3.9 Depth conversion methodology.

Fig. 3.10 is a depth map of top Brent as mapped on the 2013 PGS MegaSurvey Plus, using the base case depth conversion method. It is now possible to see an area of inversion in the vicinity of the main N-S trending fault. This area of inversion will juxtapose Brent Group against Brent Group reservoir units and introduces an extra element of risk to the trap.

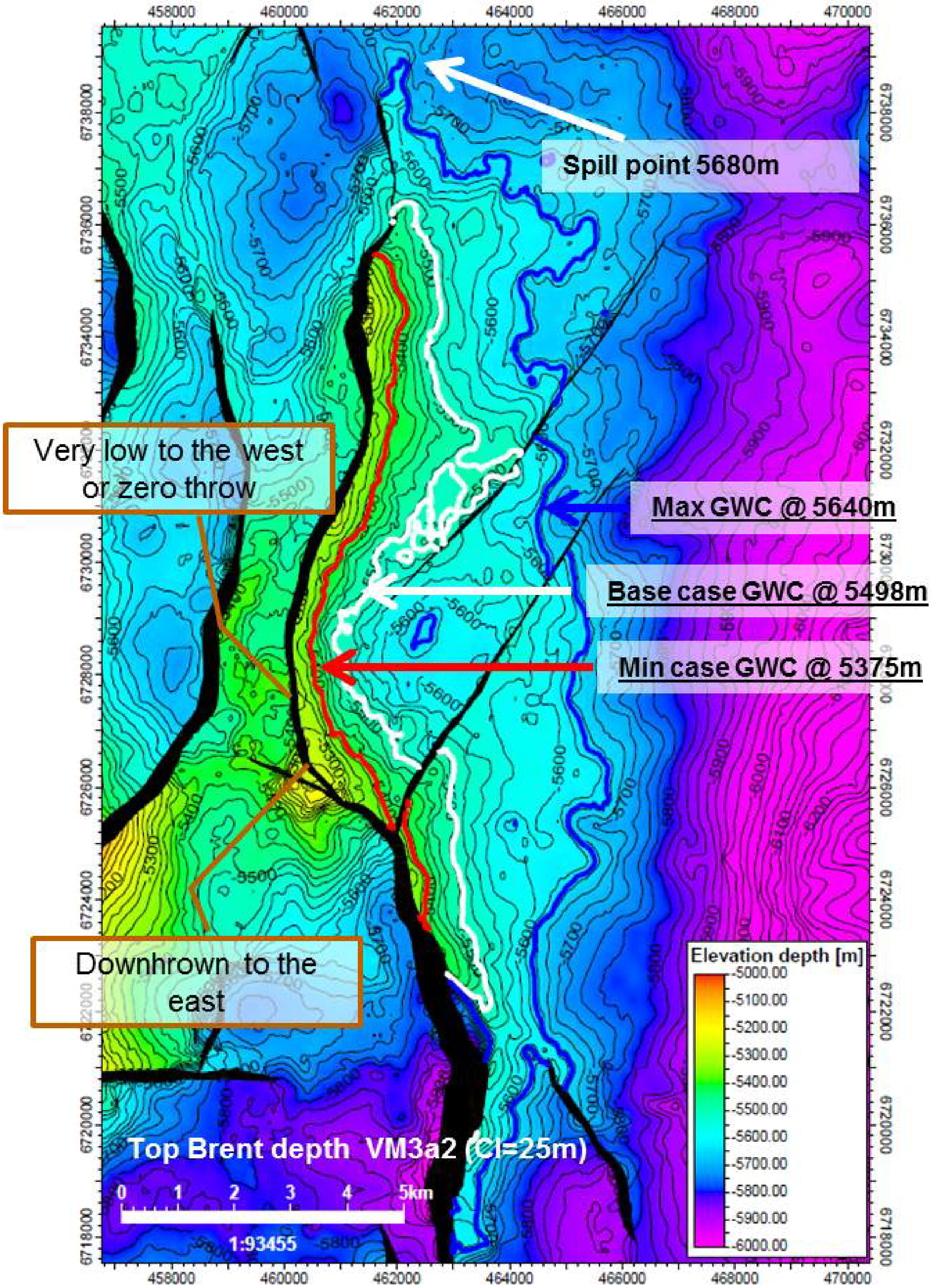


Fig. 3.10 Current Top Brent Group Depth Map. *Tingen structure as mapped on PGS Megamerge Plus (ex-NX10M02) with revised depth conversion. GWC contacts are now constrained by top seal and fault seal analysis.*

Trap Integrity
A significant update to the Tingen volumes has been to the gas contact/column assumptions for the prospect. Fault seal analysis of the main N-S trending fault bouding Tingen to the west has been carried out using the lithologies from the 30/4-1 well and shale-gouge rations from the RDR fault seal database, data available through multi-company research project. It has been found that the fault is unlikely to have much additional sealing potential through Brent-Brent juxtaposition, although an upside does exist in the database. Similarly, analysis of the Heather Formation top seal over Tingen through the JIP CapRocks, a collaboration of international oil companies including BG Group and researchers at Newcastle, Cardiff, Leeds and Heriot Watt Universities, has shown that at the expected effective stress the gas column ranges capable of being held by the overlying lithology will be limited, depending on the lithology of the rocks above the reservoir. Competent laminated mudstones may hold a max column of 311m and a silty reworked mudstone facies could hold a in a max column of 123m. The summary of the findings from these methods are shown below along with the contact range carried through for the volumetric analysis.

METHOD	PMIN	P50	PMAX
TOP SEAL ANALYSIS	5373m	5561m	5642m
FAULT SEAL ANALYSIS	5412m	5435m	5610m
DECISION FOR INPUT TO VOLUMETRICS	USE MINIMUM TO MAINTAIN RANGE	USE MID-POINT OF METHODS	USE MAXIMUM TO MAINTAIN RANGE
GAS CONTACT FOR VOLUMETRICS	5373m	5498m	5642m

The presence of a potential gas chimney over the crest of the Tingen prospect does not affect our assessment of trap integrity, as a partial fill scenario is still a strong possibility. Equilibrium may be achieved between gas escape and migration into the structure.

3.3 Source and Migration

During the APA 2012 evaluation, the preferred charging mechanism for Tingen and the other Brent prospects in the basin centre was expected to be downward migration of hydrocarbons from Upper Jurassic Heather Formation. The potential is shown locally by offset well 30/4-1 and basinwide by many of the other wells in the database.

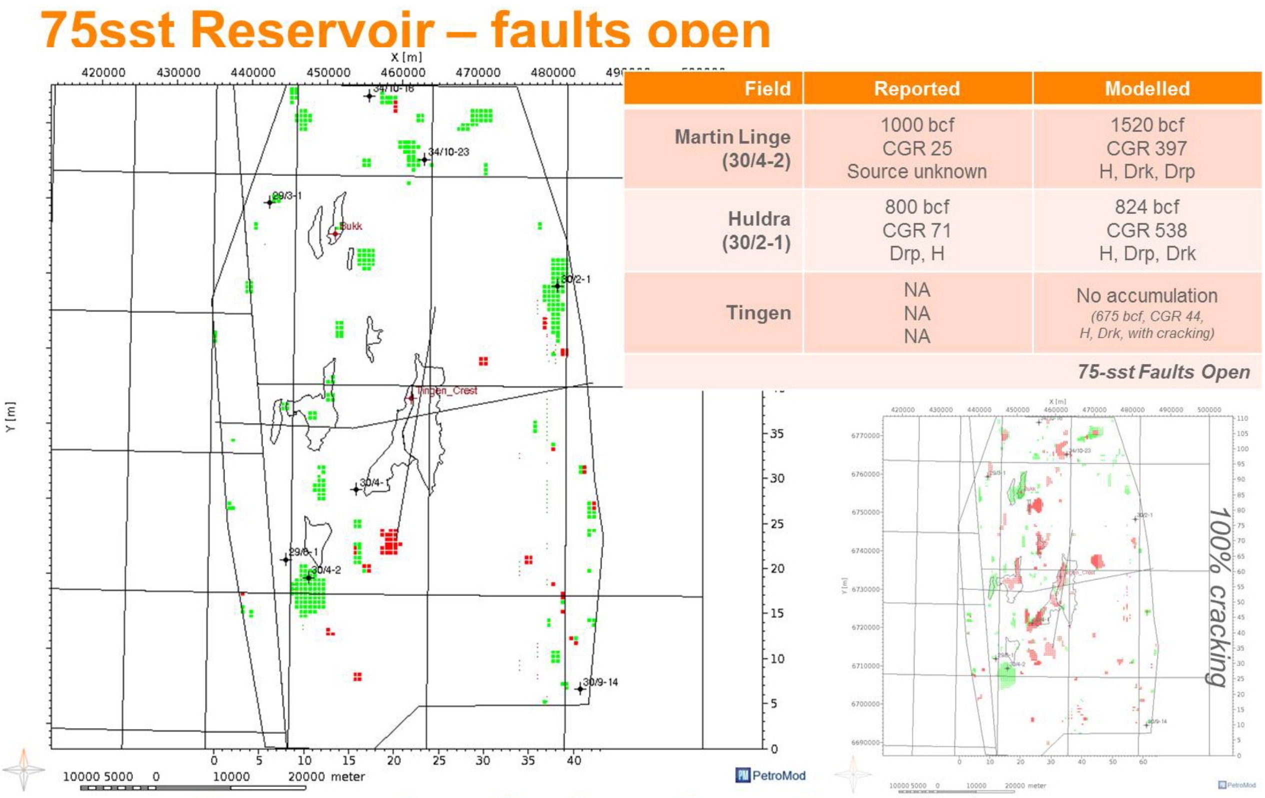
The Heather Formation is of type II/III kerogen with TOC mean values from 1.44 to 4.87% and HI mean values between 40 and 452 on the offset wells and it is volumetrically very significant. The Upper Jurassic Draupne Formation source rock is unlikely to be charging Tingen as it is stratigraphically and structurally shallower than the prospect with several 100m of Heather Formation separating the two horizons. At the time of the application, additional source potential was thought to be found in stratigraphically deeper intra-Brent coals (Ness Formation) and in the underlying Drake Formation, although it was difficult to adequately quantify these source rocks.

As part of the work program for PL679 S the licence group conducted an integrated 3D basin model to further understand the petroleum system. The extent of the model covered the basin flanks in order to calibrate offset wells and discovered accumulations and also reach far enough north and south to cover the remaining prospects from the APA 2012 application. Regional mapping of all key surfaces to surfaces was carried out on the PGS MegaSurvey and the model populated with the following data: GDE maps, pressure and temperature information, source rock parameters, paleobathymetry, heat flow history and unconformity events.

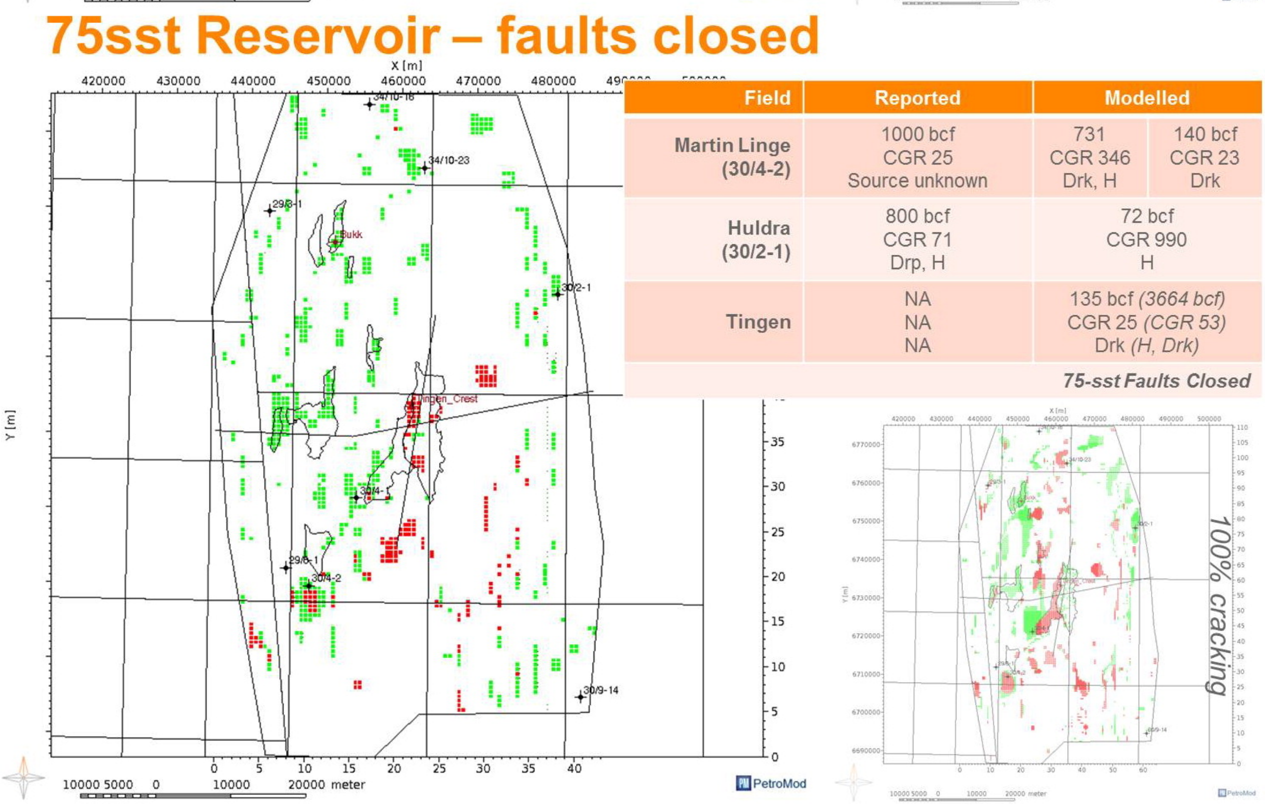
In addition, a key part of the model was to commission a compositional kinetics analysis on immature Heather Formation samples from well 30/9-2 A in order to assess the most likely phase expelled from the preferred source rock. This study was carried out by specialist geochemical consultants GeoS4.

The 3D model was constructed in Petromod. Sensitivities ran included fault seal, source rock parameters, GDE maps of reservoir horizons and heat flow histories. The accumulations seen in are gassy and are primarily charged from the underlying Drake Formation. A key point to note is that even with all faults sealing in the model the structures are significantly underfilled. It is now thought that the efficiency of the Heather Formation to expel gaseous phases downwards in a high pressure system is low. Thus the Heather Formation may no longer be the primary source rock for Tingen. A key outcome of the 3D basin modelling is the increased risk of charge to the prospects.

A further study was conducted in conjunction with the basin modelling work: fluid inclusion studies on well 30/4-1. The results of this analysis confirmed an active working Heather Formation Fig. 3.11 source rock and the presence of hydrocarbon accumulations in the crests of the nearby fault block crests. The conclusion is that the well penetrated its target below the leak point of the fault, which also confirms the conclusions of the fault seal analysis that Brent-Brent juxtapositions have little sealing potential. There is no estimate as to the size of these accumulations, but they are likely to be small as they occupy only the part of the fault blocks sealed by Heather Formation.



Field	Reported	Modelled
Martin Linge (30/4-2)	1000 bcf CGR 25 Source unknown	1520 bcf CGR 397 H, Drk, Drp
Huldra (30/2-1)	800 bcf CGR 71 Drp, H	824 bcf CGR 538 H, Drp, Drk
Tingen	NA NA NA	No accumulation *(675 bcf, CGR 44, H, Drk, with cracking)*
		75-sst Faults Open



Field	Reported	Modelled	
Martin Linge (30/4-2)	1000 bcf CGR 25 Source unknown	731 CGR 346 Drk, H	140 bcf CGR 23 Drk
Huldra (30/2-1)	800 bcf CGR 71 Drp, H	72 bcf CGR 990 H	
Tingen	NA NA NA	135 bcf *(3664 bcf)* CGR 25 *(CGR 53)* Drk *(H, Drk)*	
		75-sst Faults Closed	

Fig. 3.11 3D Basin Modelling results. *The 3D Basin Modelling was ran considering faults closed (top map) and faults open (bottom map).*

4 Update of Resource Potential

The updated evaluation of Tingen and surrounding leads (Fig. 4.1) shows a significant reduction in in-place and recoverable volumes from those calculated for the APA 2012. This is a result of the work program that has been executed since award of the licence in February 2013 and demonstrates the effectiveness of certain geoscience workflows. Fig. 4.2 shows a tornado chart showing the impact on APA 2012 volumes of each geoscience element in turn and then the final volumes (all elements combined). It can be observed that the three largest factors in reduction of volumes, are re-interpretation of the structures on the PGS MegaSurvey Plus, combined with an updated depth conversion and reassessment of gas column ranges in the structure. In addition, revised N:G ranges from petrophysical analysis and revised recovery factor had a large impact on volumes.

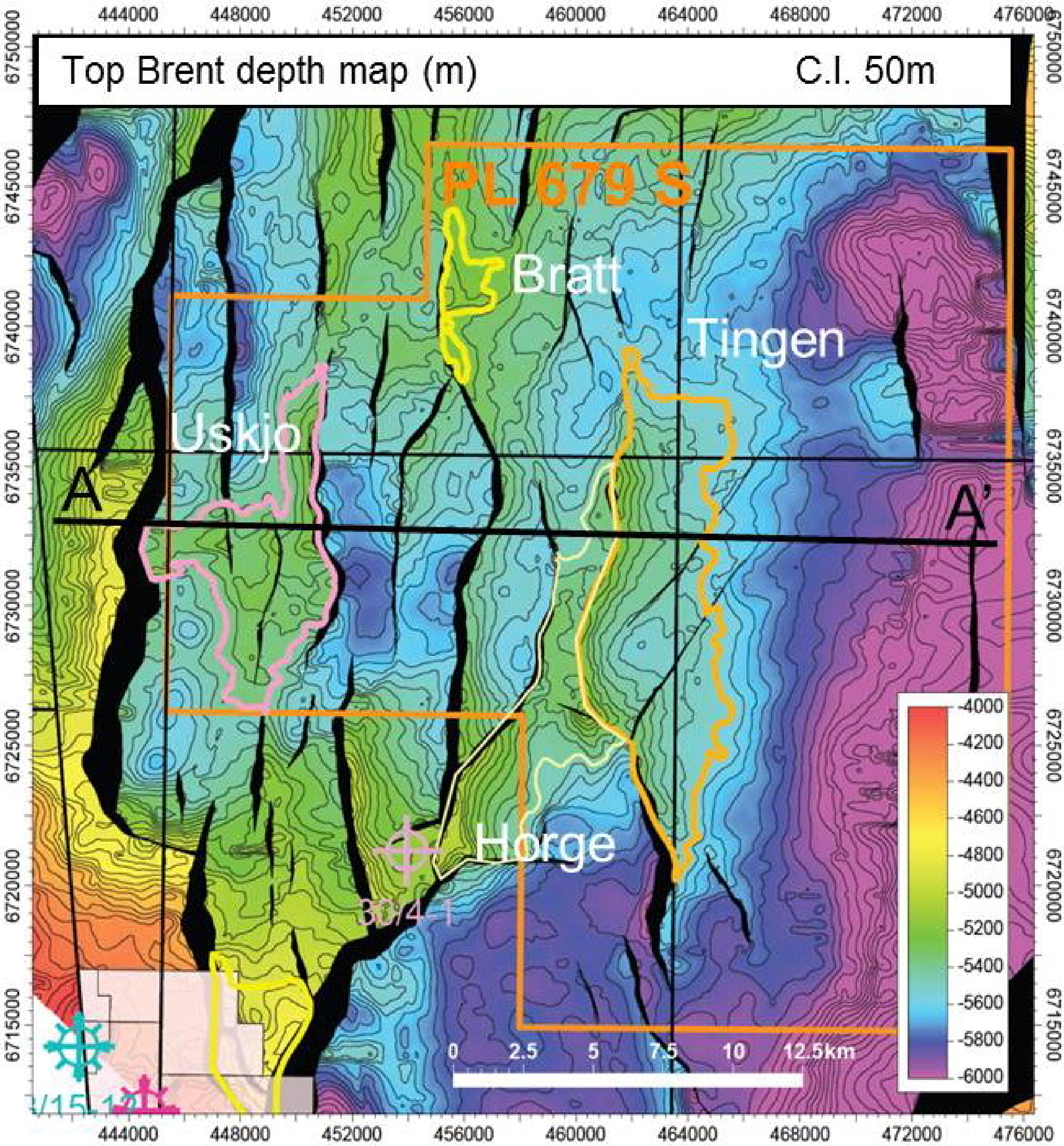


Fig. 4.1 Tingen prospect and surrounding leads on the PL679S area.

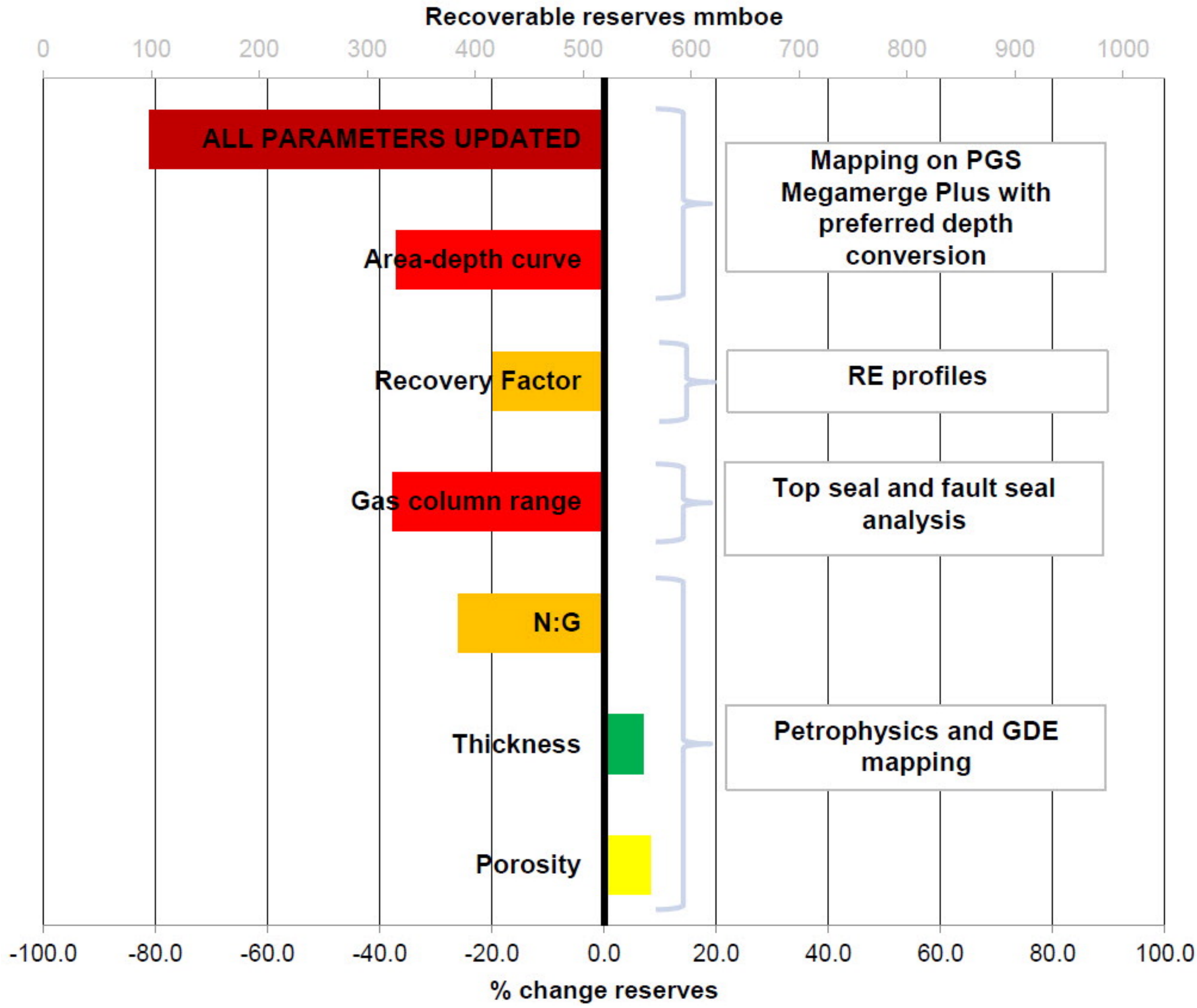


Fig. 4.2 Tornado Chart*. Tornado chart showing key elements for reducing recoverable resources in Tingen prospect*

Tingen prospect

At the time of the application, and based on the interpretation of the PGS MC3D MegaSurvey, the licence group could identify and evaluate the Tingen prospect. However, it was agreed that the quality of the data on the top reservoir could improve by reprocessing the PGS MegaSurvey and de-risk the structure mapping. During the re-evaluation of the area, with the reprocess of the PGS MegaSurvey, a new depth conversion method was applied (see 3.2 Trap), which lead to a significant decrease on the GRV of the prospect. A petrophysical study was also carried out and resulted in new parameters reservoir proprieties. Table 4.1 shows a summary of the main changes on the prospect parameters.

The revised prospect data is shown on the Table 4.2.

The table below shows a comparison of the most recent Tingen recoverable volumes and chance of success (CoS) compared to the 2012 licence application estimates.

Table 4.1 Main changes on the reservoir parameters for Tingen prospect.

	2012 licence application			2014 licence evaluation		
	Min	Base	Max	Min	Base	Max
Crest		4900			5250	
HWC	5000	5300	5600	5373	5498*	5640
Thickness	100	300	500	190	270	512.5
Spill Point		5600		5680	5690	5825
N/G	0.4	0.65	0.8	0.2	0.4	0.8
Porosity	0.08	0.113	0.14	0.105	0.126	0.15
Recovery Factor	0.5	0.6	0.75	0.4	0.42	0.62

Table 4.2 NPD Table 5. Prospect data.

Table 5: Prospect data (Enclose map)

Block	30/1, 30/2, 30/4, 30/5	Prospect name	Tingen	Discovery/Prosp/Lead	Prospect	Prosp ID (or New!)	NPD will insert value	NPD approved (Y/N)	
Play name	NPD will insert value	New Play (Y/N)		Outside play (Y/N)					
Oil, Gas or O&G case:	Gas	Reported by company	BG Norge	Reference document				Assessment year	2014
This is case no.:	1 of 1	Structural element	Viking Graben	Type of trap	Rotated fault block	Water depth [m MSL] (>0)	120	Seismic database (2D/3D)	3D
Resources IN PLACE and RECOVERABLE		**Main phase**				**Associated phase**			
Volumes, this case		Low (P90)	Base, Mode	Base, Mean	High (P10)	Low (P90)	Base, Mode	Base, Mean	High (P10)
In place resources	Oil [10^6 Sm^3] (>0.00)					2.11	3.07	7.79	15.80
	Gas [10^9 Sm^3] (>0.00)	7.77	12.90	25.40	50.00				
Recoverable resources	Oil [10^6 Sm^3] (>0.00)					0.94	1.22	3.90	8.17
	Gas [10^9 Sm^3] (>0.00)	3.42	5.02	12.60	25.70				
Reservoir Chrono (from)	Bajocian	Reservoir litho (from)	Ness Formation	Source Rock, chrono primary	Toarcian	Source Rock, litho primary	Drake Formation	Seal, Chrono	Bathonian to Kimmeridgian
Reservoir Chrono (to)	Bathonian	Reservoir litho (to)	Tarbet Formation	Source Rock, chrono secondary	Bathonian to Kimme	Source Rock, litho secondary	Heather Formation	Seal, Litho	Heather Fomation
Probability [fraction]									
Technical (oil + gas + oil & gas case) (0.00-1.00)	0.14	Oil case (0.00-1.00)		Gas case (0.00-1.00)		Oil & Gas case (0.00-1.00)			
Reservoir (P1) (0.00-1.00)	0.40	Trap (P2) (0.00-1.00)	0.85	Charge (P3) (0.00-1.00)	0.80	Retention (P4) (0.00-1.00)	0.50		
Parametres:	Low (P90)	Base	High (P10)	*Comments*					
Depth to top of prospect [m MSL] (> 0)		5250							
Area of closure [km^2] (> 0.0)									
Reservoir thickness [m] (> 0)	226	292	389						
HC column in prospect [m] (> 0)	183	250	321						
Gross rock vol. [10^9 m^3] (> 0.000)	4.210	11.900	32.200						
Net / Gross [fraction] (0.00-1.00)	0.29	0.43	0.60						
Porosity [fraction] (0.00-1.00)	0.12	0.13	0.14						
Permeability [mD] (> 0.0)									
Water Saturation [fraction] (0.00-1.00)	0.33	0.26	0.20						
Bg [Rm3/Sm3] (< 1.0000)									
1/Bo [Sm3/Rm3] (< 1.00)									
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)									
Recov. factor, oil main phase [fraction] (0.00-1.00)									
Recov. factor, gas ass. phase [fraction] (0.00-1.00)									
Recov. factor, gas main phase [fraction] (0.00-1.00)	0.40	0.46	0.60						
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)	0.40	0.46	0.60	For NPD use:					
Temperature, top res [°C] (>0)				Innrapp. av geolog-init:	NPD will insert value	Registrert - init:	NPD will insert value	Kart oppdatert	NPD will insert value
Pressure, top res [bar] (>0)				Dato:	NPD will insert value	Registrert Dato:	NPD will insert value	Kart dato	NPD will insert value
Cut off criteria for N/G calculation	1.	2.	3.					Kart nr	NPD will insert value

Recoverable resources	P90	Mean	P10	P90	Mean	P10	CoS
	Main Phase (Gas) $10^9 sm^3$			Associated Phase (Condensate) $10^6 sm^3$			%
Tingen 2012 licence application	13.1	66.1	137.7	3.86	8.25	43.9	13.5
Tingen 2014 licence evaluation	3.4	12.7	25.7	0.931	3.91	8.2	15.3

PL679S leads

A total of 13 additional middle Jurassic structural closures were identified around the Tingen prospect (Table 4.3). Three of these leads are located within the PL679S area and considered key leads: Uskjo, Hest and Bratt. Hest lead was identified after the APA 2012 evaluation, therefore there is no comparison with APA 2012 results.

Table 4.3 Summary of Middle Jurassic Leads as presented during APA 2012 evaluation.

Lead Name	Depth (m)	P50 Area (km2)	P50 HC Column	P50 porosity	P50 gas expansion (Bg)	P50 Rec (10*6 Sm3 o.e.)
Lyng	4050	9.8	300	0.14	0.0030	22.5
Bukk	4650	21.6	300	0.12	0.0027	32.4
Odda	4700	23.1	400	0.12	0.0026	36.2
Asp	5100	12.3	300	0.11	0.0026	14.4
Brimse	4650	19.8	200	0.12	0.0026	25.4
Heng	4950	22.7	300	0.11	0.0026	52.6
Tuns	4650	24.9	300	0.12	0.0027	44.6
Riska *	4500	23.4	300	0.12	0.0027	12.8
Lind	4850	8.4	200	0.11	0.0026	7.4
Uskjo	5200	19.7	200	0.11	0.0026	19.1
Uska	4500	75.4	400	0.12	0.0028	54.3
Bratt	5000	7.5	150	0.11	0.0025	2.7
Krog	5400	6.2	150	0.11	0.0025	4.6

The leads were also re-evaluated after APA 2012. In terms of reservoir and source & migration elements Uskjo is identical to Tingen as it has the same reservoir depth and expected hydrocarbon system. However, following remapping on the PGS MegaSurvey Plus survey (ex-NX10M02) and in particular, as a consequence of the new depth conversion methods, the new Uskjo crest was interpreted deeper than previously, at 5410m and the volumes of this structure were reduced significantly. The new new depth conversion also affected the spill point and hydrocarbon column high, with a significant reducing on mode column high from 355m to 90m. Due to these changes on the interpretation, the hydrocarbons P50 recoverable volumes were reduced to 1.46 10*6 Sm3 OE. Bratt lead showed little chance on the volume analysis comparing to the results obtained during the APA 2012 evaluation.

5 Technical Evaluations

The development concept for Tingen is shown in Fig. 5.1. Production profiles were made assuming a mean case of 1mD permeability for the Brent Group (mean case and 5mD for the high case). Tingen prospect inplace volumes ranges from 9.46 x10^6 Sm^3 (P90) to 62.4 x10^6 Sm^3 (P10), and mean inplace volume is 31.6 x10^6 Sm^3. The recoverable volumes ranges from 4.21 x10^6 Sm^3 (P90) to 32.2 x10^6 Sm^3 (P10), and mean inplace volume is 15.7 x10^6 Sm^3. Production volumes for the low assumption of 0.5mD were too small to be economic. The wells are considered to be HPHT, with temperature around 180°C and pressure of around 1070bar.

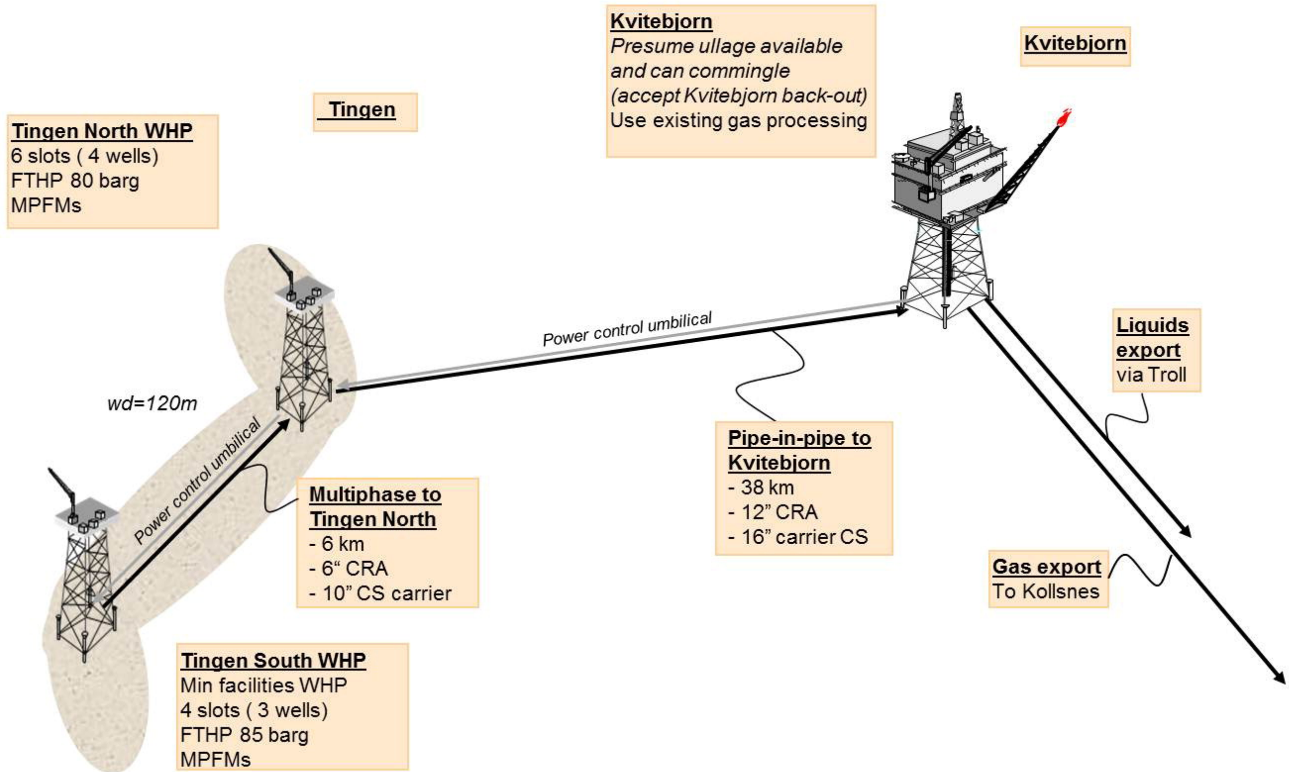


Fig. 5.1 PL679S development concept*. Assuming development of Tingen tie-back to the Kvitbjørn producing facility.*

The assumed development scenario is one where Tingen gas and liquids would be developed by; (i.) mean case - 7 production wells drilled from two well head platforms tied back to the Kvitbjørn processing facility and a (ii.) high case - where twelve gas producers would drilled from two well head platforms tied back to Kvitbjørn by a 38km pipeline, liquid export then via the Troll field and gas export to Kolisnes.

6 Conclusions

The PL679S partnership decided to relinquish the licence following an extensive licence program which included:

- PreSTM reprocessing of the NX10MO2 3D survey as part of the multiclient 2013 PGS NNS MegaSurvey Plus 3D PreSTM reprocessing.
- Seismic time and depth mapping based on the PGS NNS Plus PreSTM full stack.
- Petrophysical evaluation of key offset wells.
- Fault seal and top seal analysis.
- Gross depositional environment (GDE) mapping.
- Detailed reservoir quality studies of the Brent Group using the Touchstone reservoir modelling software to model effect of burial on reservoir properties.
- 3D basin modelling & kinetic study of the Heather Formation.
- 30/4-1 fluid inclusion study.

Three dip/structural closed prospects remain on the licence, Tingen, Uksjø and Bratt. The reduction in volumes of the main prospect Tingen following remapping of the structure and detailed geological studies have shown the critical risk of reservoir effectiveness remains high. The evaluation of the remaining prospects show the same decrease in volumes and permeabilities compared to the evaluation at the time of licence application.

All the work commitments in the licence have been fulfilled and through extensive subsurface studies the partnership has concluded that the remaining prospectivity is not economically viable and does not support the drilling of an exploration well. Based on these assumptions the licence group unanimously agreed to drop the licence at the Drill or Drop milestone on the 8th August 2014.