ACORN & BEECHNUT

INTEGRATED SUBSURFACE REPORT

MAY 2015

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1 Introduction

1.1 Project Background

Seaward Production Licence P2038, comprising part-blocks 29/8a and 29/9b and containing the Acorn and Beechnut undeveloped oil discoveries, was awarded to Shell (100%) in January 2013 as part of the UK 27th licencing round. In March 2013 ExxonMobil acquired a 50% interest in the licence, exercising its right under the UK JV'65 agreement. The work programme in the initial 4 year licence term includes 2 firm commitment activities:

1. Obtain 100 km^2 of 3D seismic data in the blocks.
2. Drill a well on the Beechnut Prospect to 3932 m to evaluate the Jurassic Fulmar.

The licence blocks are located on the margin of the West Central Graben and Western platform in the UK Central North Sea. The discovered fields are high pressure/high temperature oil accumulations within Triassic Skagerrak (Acorn North) and Jurassic Fulmar (Acorn South, Beechnut) reservoirs. There are also several exploration leads within the licence area.

Project economic viability at the time of licence award was based primarily on a tie-back to a proposed nearby Fram FPSO. However, the FPSO project is no longer proceeding requiring a change to the Acorn Beechnut development concept, most likely to a higher cost tie-back to the more distant Shearwater platform.

A fully resourced development team has conducted studies within the licence with the objective to:

1. Demonstrate a line of sight to an economic Acorn and Beechnut development.
2. Select the optimal location to drill the commitment well.

In order to fully leverage the knowledge and expertise of the licence partners, an integrated Shell/ExxonMobil exploration and development subsurface team was established, including the secondment of an ExxonMobil geoscientist into the evaluation team. Oversight and assurance was provided jointly by both Shell and ExxonMobil technical experts.

This report documents the integrated subsurface work conducted to support the Acorn & Beechnut projects.

1.2 Seismic Data Coverage

Several seismic surveys have been acquired over blocks 29/8a and 29/9b, with several reprocessing of the same acquisition. All the available data has been summarised in Table 1 with the three main datasets used in this work shown in Figure 1.

Table 1 Summary of seismic data covering blocks 29/8a and 29/9b

Dataset	Type	Acquired	Processing	Areas Covered	Angle Stacks	Open works Project Project	Full Stack Volume
Q28/29	Conventional	1999	2010-11 PSTM	All	Yes	HPHT_CNS_IP	
Q30ph4	Conventional	2004	2011 HPHT PSDM	All	Yes	HPHT_CNS_IP	R2746_10PrDMke_Full _T_Rzn_RMO_Deabs
TOMO ML	Conventional	2004	2014 CGG PSDM	All	Yes	ACORN_BEEC HNUT_IP	Final_Stack_in_Time_T OMOML
Q30 Ph8ex	Broadseis	2014	2014 CGG PSTM	Acorn North Only	No	CURLEW_BB_ Q30PH8E_IP	P3261_14R14PrTM_A 0030_T_Rzn_Shp
Q30 Ph8ex	Broadseis	2014	2014 CGG PSDM	Acorn North Only	No	CURLEW_BB_ Q30PH8E_IP	P3261_14R14PrDMk_ A0030_T_Rzn

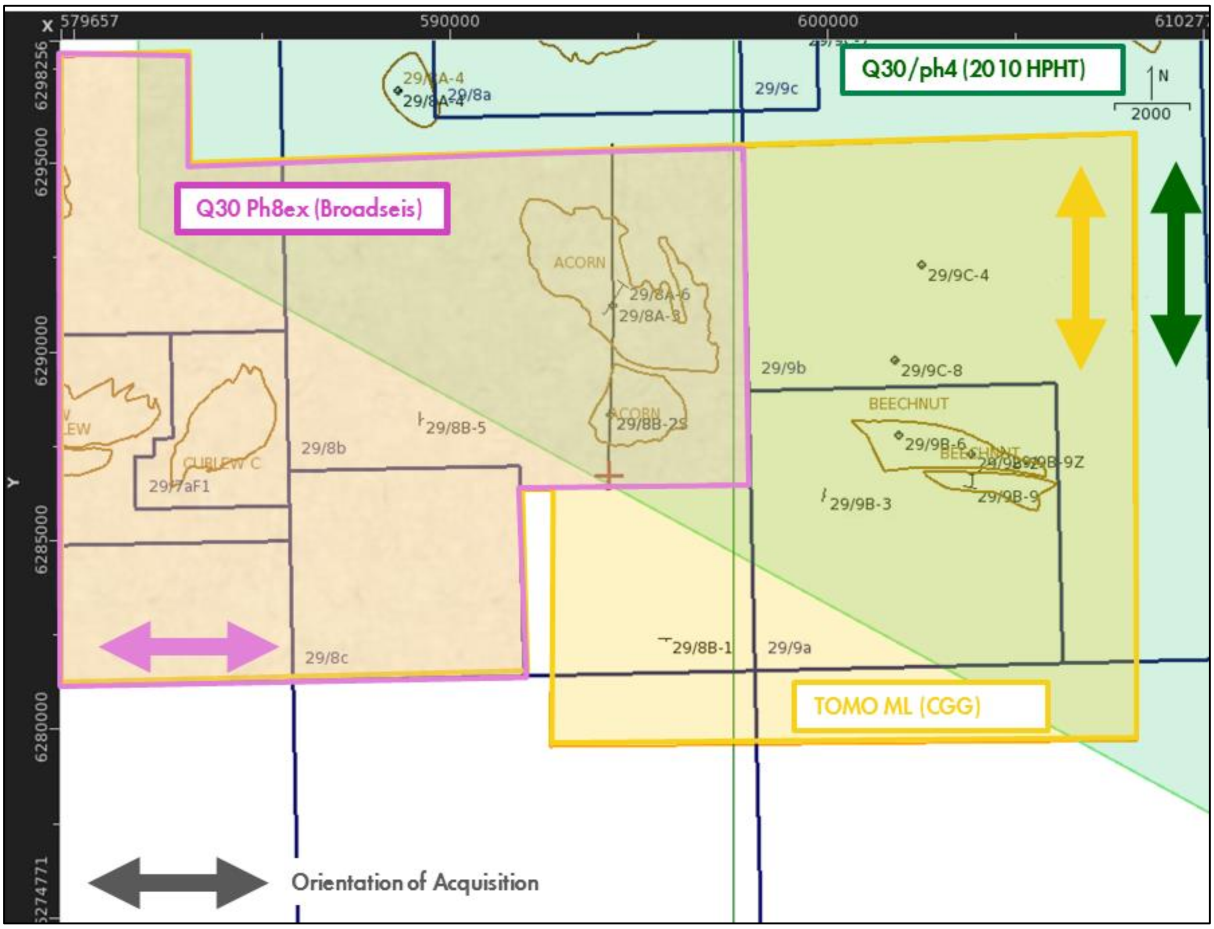


Figure 1 Summary of the extent of seismic datasets used in this evelauation, with acquisition orientations indicated

In addition to the well data the area is also covered by 2 different seismic velocity earth models. The HPHT model was generated in house as part of a reprocessing of the cornerstone HPHT dataset in 2011. The CGG Model was built externally by CGG as part of the TOMO ML reprocessing of the data in 2014. Both models covered large areas and as a result not all of the wells in the Acorn/Beechnut area were used to constrain them.

1.3 Drilling History – Blocks 29/8 & 29/9

1983: 29/8b-2 &29/8b-2s drilled by Union Oil. Oil discovered in Fulmar sands (area now referred to as Acorn South). Well TDed in Smith Bank Fm.

1985: 29/8a-3 drilled by Shell/Esso. Acorn discovery well; producible oil in Triassic Skagerrak reservoir sands. Reservoir pressure of 10997 psia at 13200ft tvdss datum. DST oil rates of 5000 bbl/d. Wet Cromarty sands in overburden section (Oak Prospect). Well TDed in Smith Bank Fm.

1985: 29/9b-2 drilled by Premier Oil. Beechnut East discovery well; successful oil DSTs in Jurassic Fulmar and Triassic sands. Reservoir pressure of 11040 psia at 13800ft tvdss datum. DST oil rates of ~7000 bbl/d. Well TDed in Skagerrak Fm.

1986: 29/9b-3 drilled by Premier Oil. Beechnut West unsuccessful dry hole. Well TDed in Rattray Fm.

1988: 29/8a-4 drilled by Shell/Esso. Oil discovered in Pentland and Skagerrak sands. Well TDed in Skagerrak Fm.

1989: 29/9b-6 drilled by Premier Oil. Proven producible oil discovered in Fulmar sands. Reservoir pressure of 11231 psia at 13800ft tvdss datum. DST oil rates of ~1200 bbl/d. Well TDed in Zechstein Fm.

1992: 29/9c-8 drilled by BG. Dry hole with Triassic Skagerrak sands (Fulmar absent). Well TDed in Skagerrak Fm.

2001: 29/9b-9 drilled by Hess. Proven producible oil in Fulmar sands. Reservoir pressure of 10625 psia at 13800ft tvdss datum. DST oil rates of ~2400 bbl/d. Well TDed in Zechstein Fm.

2001:29/9b-9z drilled by Hess. Incomplete, tight Fulmar section, single oil sample obtained. Reservoir pressure of 11130 psia at 13800ft tvdss datum. Well TDed in Rattray Fm.

2009: 29/8a-6 drilled by Venture/Centrica. Horizontal well with EWT in Triassic Skagerrak formation. Reservoir pressure of 10901 at 13200ft tvdss datum. Proven producible oil from EWT, initial rates of 62000 bbl/d declining to 5000 bbl/d. Well TDed in Skagerrak Fm.

1.4 Geological Setting

Permian (299-251Ma) During this period, the North Sea climatic conditions were hot and arid. During the Permian two key depositional sequences occur, the terrestrial desert sandstones of the Rotliegendes Formation overlain by marine carbonates and evaporites of the Zechstein Group. It is not uncommon for salt layers over 1000m in thickness to be observed and these represent multiple phases of quiescence and evaporation.

Triassic (251-199Ma) During the Triassic rifting took place and extensional tectonics dominated. This rifting led to the initiation of many of the SSE-NNW orientated major basement faults. The Triassic also saw the creation of large northwesterly trending sedimentary basins. Structural reconstruction of this period is complicated by the onset of halokinesis driven by sediment input into the basin and the onset of faulting that led to the creation of the pod-interpod structures.

Early to Mid-Jurassic (199-161Ma) Little rifting took place during this period while Europe continued to migrate northwards. This period represents one of tectonic quiescence, with infilling of the passively subsiding rift basins taking place and a noticeable change in sediment type from fluvial to a predominant marine facies. Lower Jurassic formations are believed to have been deposited in far more substantial quantities than are observed throughout the study area with uplift associated with thermal doming causing erosion and development of the Mid-Jurassic Unconformity.

Late Jurassic (161-146Ma) The Late Jurassic represents deposition of source rock the Kimmeridge Clay as well as syn-depositional shallow marine clastic reservoir intervals such as the Fulmar Formation. The Late Jurassic also saw the creation of the basic structural style observed in the North Sea today. Extension took place spreading from the Arctic in the North along three major axes, the North Viking Graben, the Moray Firth Basin and the Central Graben. The Middle to Late Jurassic was characterised by multiple phases of rifting, climaxing in the Late Jurassic, separated by periods of relative tectonic quiescence. Thus it is not uncommon for Late Jurassic formations to unconformably overly those of the Early Jurassic or even the Triassic as is observed on many horst blocks.

Cretaceous (146-65Ma) The Cretaceous in the North Sea saw the relaxation of extensional tectonics and the onset of passive thermal subsidence covering the syn-rift topography with transgressive sediments and forming the Base Cretaceous Unconformity. Sedimentary development during most of the Cretaceous was primarily influenced by pre-existing topography, halokinesis and eustatic sea level fluctuations. The Cretaceous was a time of greenhouse conditions and experienced a large rise in sea level that saw the deposition of thousands of meters of pelagic chalk that comprise the chalk group.

Tertiary (65MA-Recent) While the North Sea was undergoing post rift thermal subsidence, West of Britain was experiencing thermal uplift that was leading to an increase in clastic input into the North Sea due to erosion of the Scottish Highlands and Shetland platform. This led to the deposition of numerous fan systems including the Maureen, Andrew, Forties and Rogaland fans. Prolific turbidite sequences belonging to the likes of the Forties Formation were formed in the distal parts of these fan systems. Sea level rise and tectonic quiescence during the intervening periods led to clastic supply being cut off and the widespread deposition of pelagic muds.

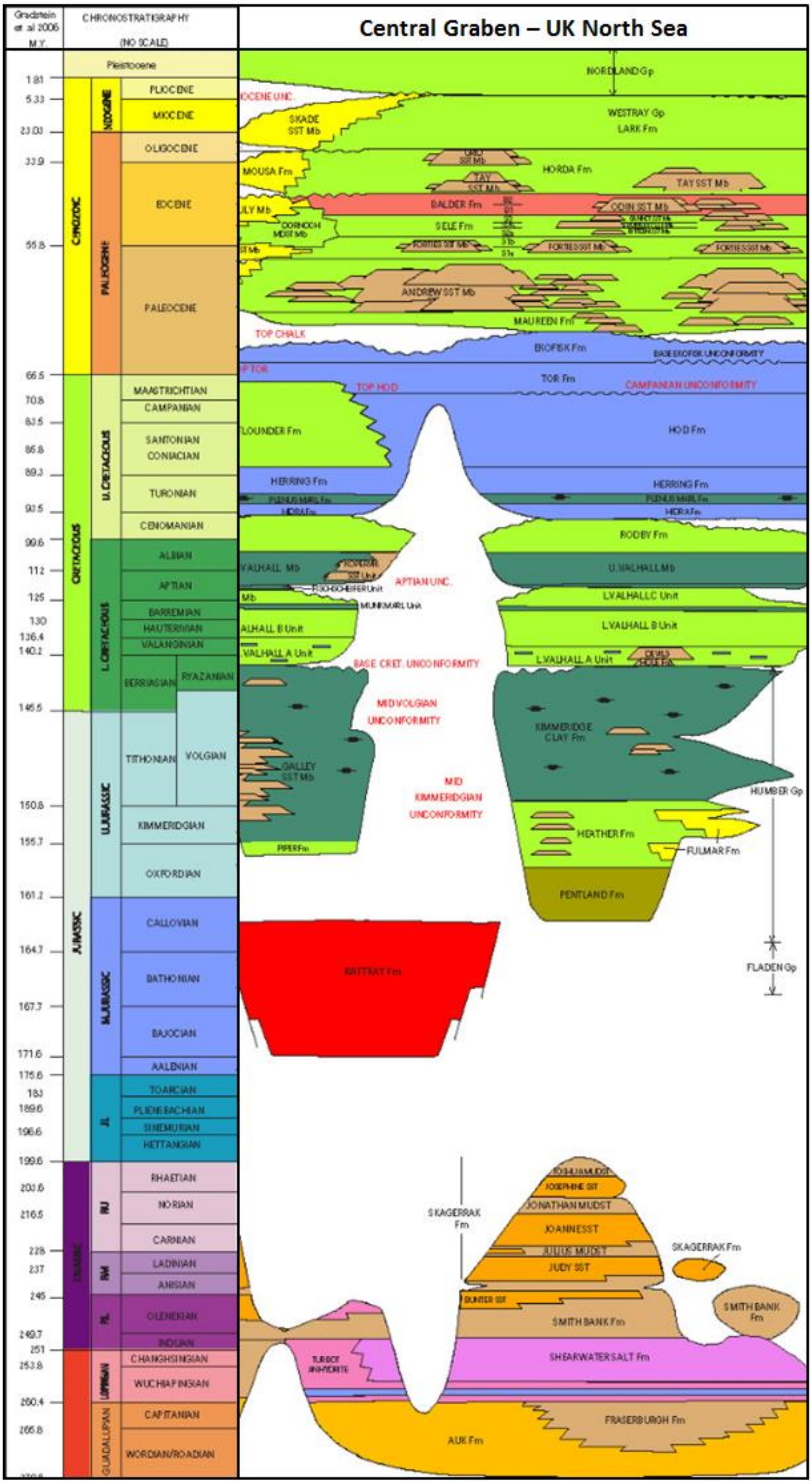


Figure 2 Regional Stratigraphy

1.5 Regional Structure

A robust regional structural interpretation is vital in the Beechnut area as a predictor of Jurassic vs. Triassic reservoir presence. This chiefly involves the delineation of the “pod vs interpod” areas. These are the fundamental tectonic building blocks of the Permian-Jurassic structure, and an understanding of these gives predictive power over Fulmar vs. Skaggerak reservoir distribution. The key surfaces for this are Top Rotliegend, Top Zechstein and the Base Cretaceous. Before focusing on individual fields, the major regional surfaces were remapped on the 2010 HPHT dataset. A detailed description of this work can be found in the Beechnut Seismic Interpretation Report.

In general, block 29 is underpinned by a series of Rotliegend fault blocks, which provide nucleation points for Zechstein Salt structures. Where salt diapirs and salt walls are present, these form the “Interpod” areas, where mid-upper Jurassic sediments can be deposited, including Fulmar sands. Where the underpinning Zechstein salt has evacuated, the Triassic Smith Bank and Skagerrak fault blocks form resistant “Pods”, and the Skagerrak tends to be the uppermost reservoir unit.

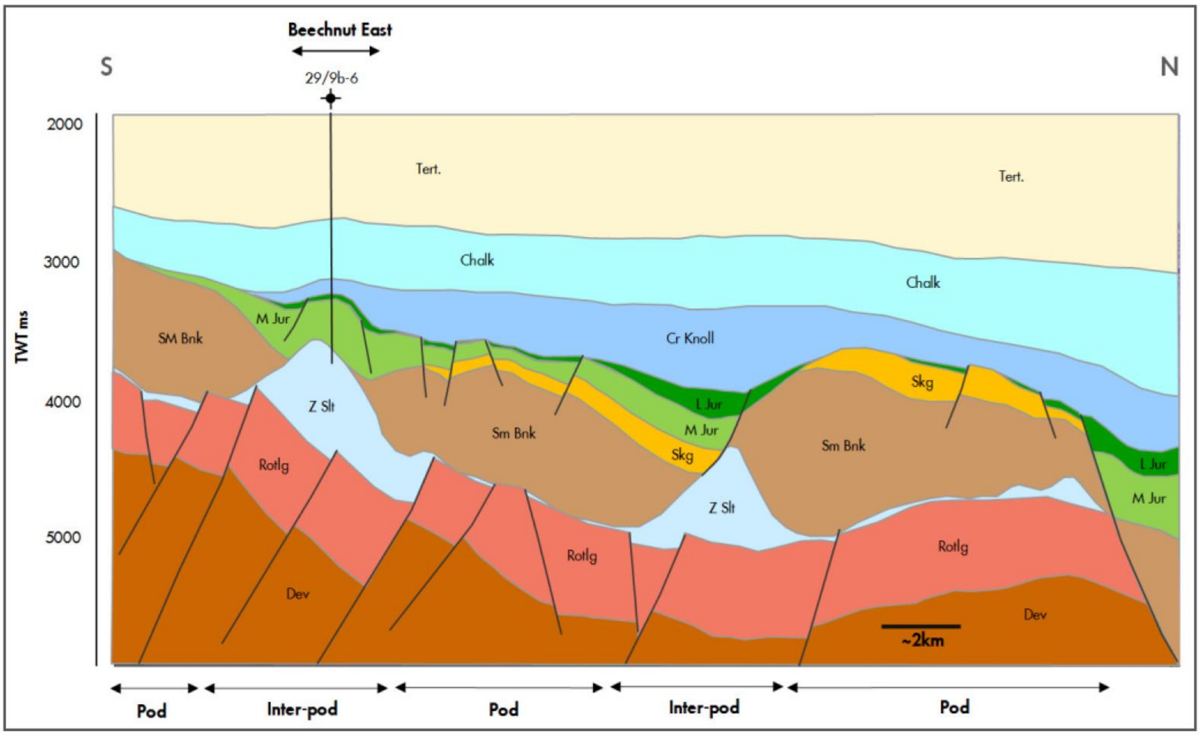


Figure 3: Schematic N-S cross section of Beechnut Area, demonstrating Pod-Interpod concept

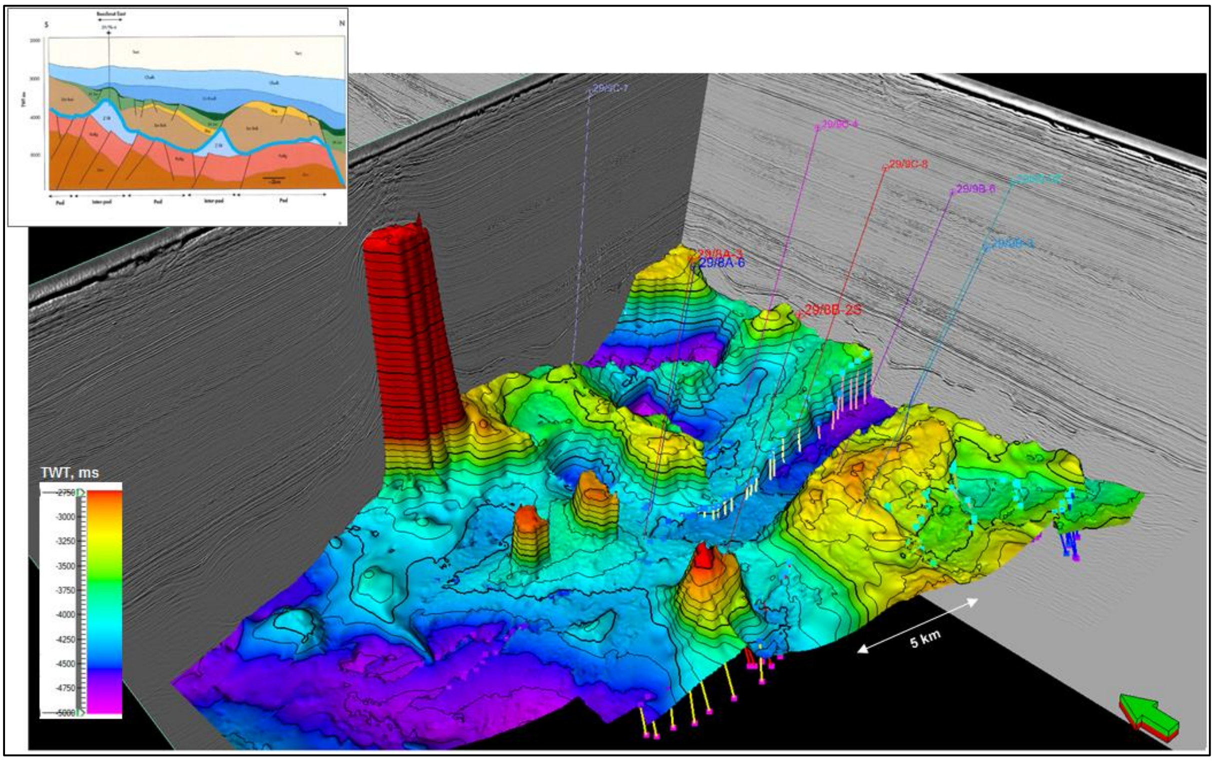


Figure 4: 2014 Regional Top Zechstein (2010 HPHT data)

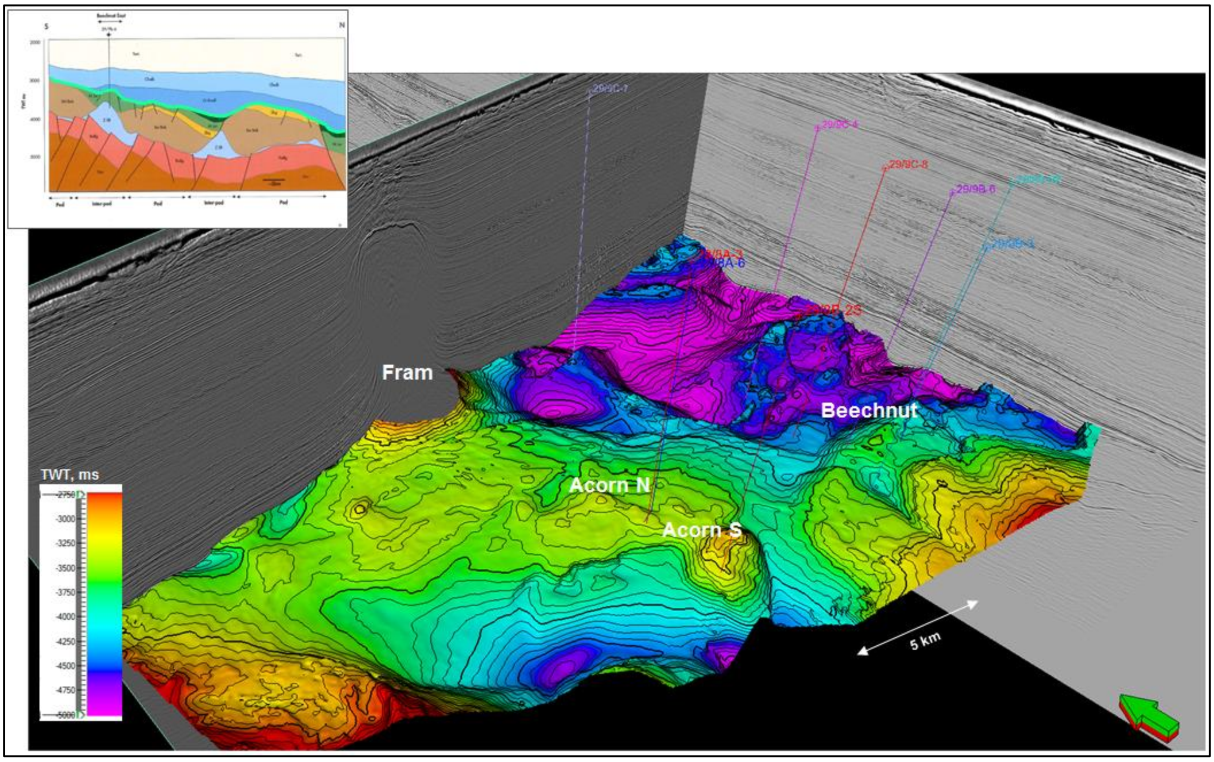


Figure 5: 2014 Regional Base Cretaceous Unconformity (2010 HPHT data)

2 Acorn North Field

2.1 Geology

The Skagerrak reservoir within the Acorn Field was deposited in a dryland setting within ephemeral to intermittent streams with associated overbank splays and playa. The Acorn area was located in a medial position within the southward-draining fluvial system, several hundred kilometres down-palaeoflow from the basin margins. To the south the system ultimately terminated as mud-rich splay deposits within coastal sabkha and playa on the northern margin of the Muschelkalk seaway. In common with the Skagerrak in the Heron Cluster area the Acorn reservoir comprises channel belt deposits interbedded with terminal splay and playa facies. However, the proportion of channel belt deposits is lower, upper bar deposits are more heterolithic, and lower bar and channel thalweg deposits are finer grained than those seen c. 50 km to the north in the Heron area. This facies change results in the loss of a connected, higher permeability network that is critical in effectively draining Triassic fluvial reservoirs in more proximal locations. The compartmentalising shales seen in the Heron Cluster fields are also considered to be as prevalent in Acorn. Overall Acorn has a higher proportion of finer grained, more heterolithic channel belt sandstones and common occurrence of inclined barriers and baffles, resulting in a tortuous connectivity within a relatively poor quality reservoir.

2.1.1 Structural Geology

Early Triassic rifting, followed by middle to late Triassic post-rift thermal subsidence and subdued polyphase extension dominated the filling style of the Triassic basins. Rifting propagated southward from the Arctic, via the Northern and Central North Sea regions, and ultimately penetrated the Southern North Sea. The early, syn-rift basin fill is composed of playa, sabkha and lacustrine mudrocks (Smith Bank Formation) punctuated by localized fluvial-aeolian Bunter fluvial deposits. The section rests on a significant thickness of Permian halite (Zechstein), and this was mobilized during extension, resulting in dramatic thickness variations and the formation of minibasins. However, over much of the area the largely postrift Skagerrak shows more subdued thickness variations, and on seismic has a more tabular, layered fabric on a kilometre scale, suggesting that salt movement had slowed as the instability induced by extensional faulting ceased. Although halokinesis was more subdued, the differential subsidence induced by sediment loading locally influenced the stacking of channel belts and the relative proportion of channel versus floodplain deposits, but the basinwide dispersal of Skagerrak sands would indicate that any surficial expression of this subsidence was unable to maintain areas of sustained lacustrine ponding and divert or block river courses.

2.1.2 Stratigraphic Framework

Biostratigraphic data from 29/8a-3 (Vieira, 2015), although sparse, are sufficient to establish the upper part of the Skagerrak section in this well as TriassicEarly Ladinian (based on the occurrence of the penetrated section is likely to comprise the Judy Sandstone Member (Figure 6), in contrast to amerosporites secatus and Sulcatisporites kraeuseli), indicating that the bulk of the the interpretation presented in Goldsmith et al. (1995). The uppermost, mud-prone Skagerrak in the

Acorn section may be in part equivalent to the basal part of the Julius Mudstone Member. Deeper in the section comparison with offset wells (e.g. 30/7a-4) suggest that 29/8a-3 has penetrated the Bunter Sandstone equivalent.

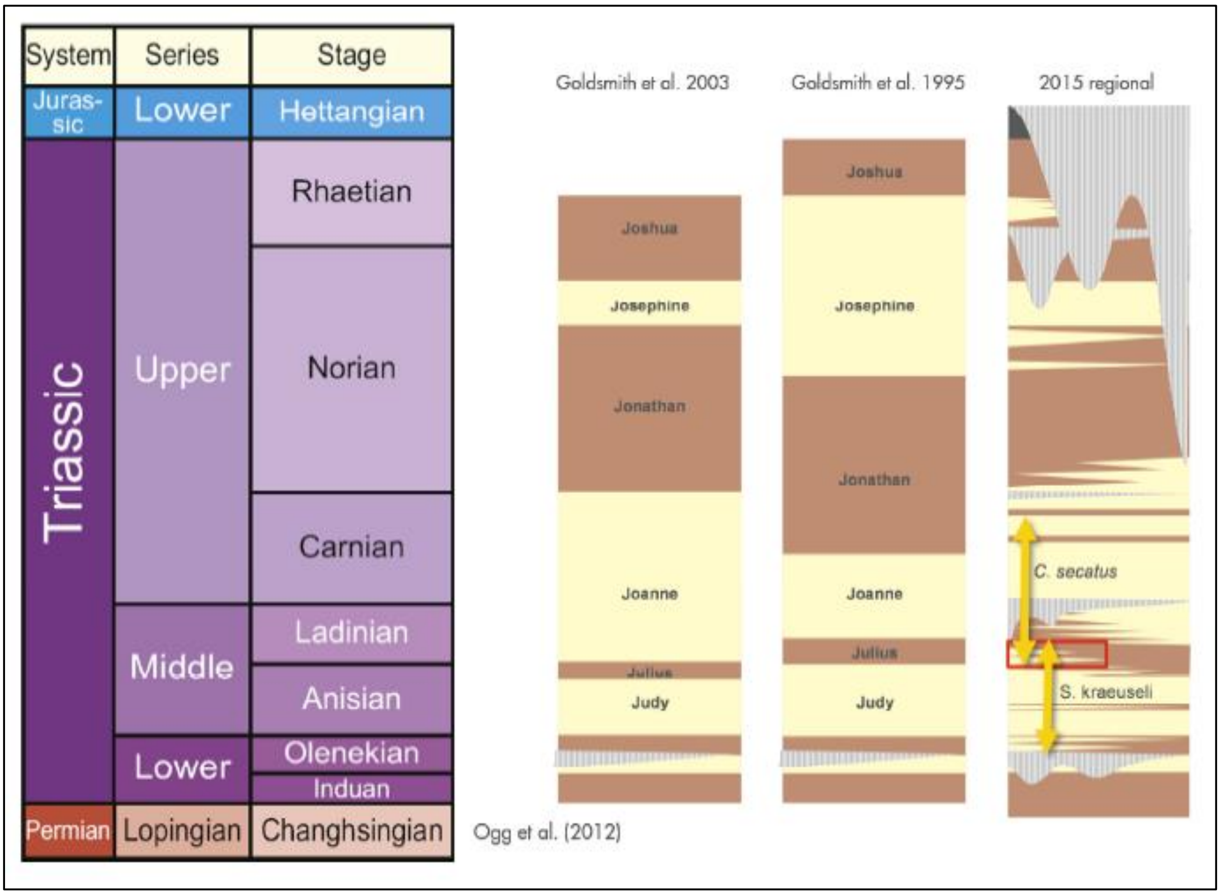


Figure 6: Acorn Field Stratigraphic Framework

2.1.2.1 Well Correlation

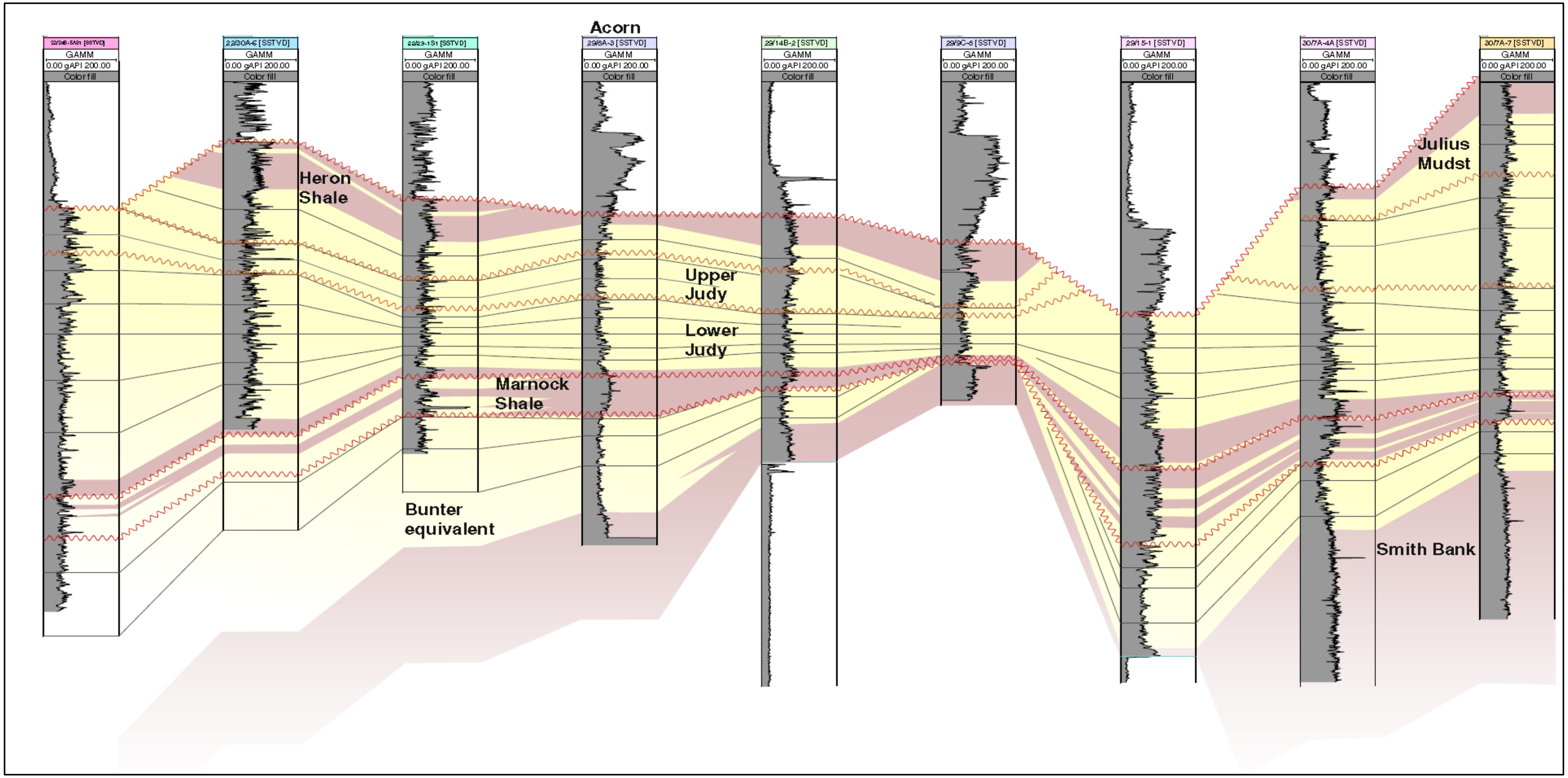


Figure 7: Acorn Field Offset Well Correlation

2.1.2.2 Core Data

Within Acorn c. 177 ft of core data were available from well 29/8-3 and wireline log data from 29/8-3 and 29/8-6. In addition, broadly time-equivalent, cored sections found in 29/3b-4, 29/5b-7, and uncored wells 29/6-3, 29/9c-8, 29/13b-2, 29/14b-2, 29/15-1, 29/18-1, and 29/25- 1 allow the semi-regional context to be established. As a gross simplification two endmember facies are interpreted to be present within the cored section in well 29/8-3. In addition to these, thicker mudrock successions are locally present based on wireline log data, and are interpreted based on comparison with similar cored successions seen across the Central North Sea.

Figure 8: Acorn Field Core Facies

2.1.2.3 Reservoir Units

Channel-belt facies

Channel-fill deposits comprise very fine to fine grained sandstones dominated by horizontal to low angle lamination. Cross-bedding is comparatively rare. The deposits are organised into fining-upward successions 1 – 4 m thick characterised by a basal succession of mudclastbearing, plane bedded and cross-bedded sandstones, passing upwards into more heterolithic sandstones which are interbedded with laminated siltstones. The overall context of these deposits, in demonstrably terminal systems in a region prone to evaporate precipitation, suggests that they are largely the product of streams which had a highly erratic discharge which may have been ephemeral or intermittent in nature.

Heterolithic splay deposits

These heterolithic deposits occur in association with the channel belt deposits. They typically comprise decimetre-scale, interbedded very fine to fine grained, current ripple laminated, plane bedded and cross bedded sandstones, and variably laminated and pedified mudstones with burrow mottling and rooting. These are interpreted to represent weakly confined to unconfined splay deposition

Playa/floodplain mudrocks

These deposits are not cored, but are characterised by high gamma, wide neutron/density separations in intervals that are typically up to 5 m thick. Comparison with comparable log facies across the basin suggests that these intervals are likely to comprise either rooted and burrowed floodplain mudrocks, or mud-rich heterolithic, desiccated playa deposits.

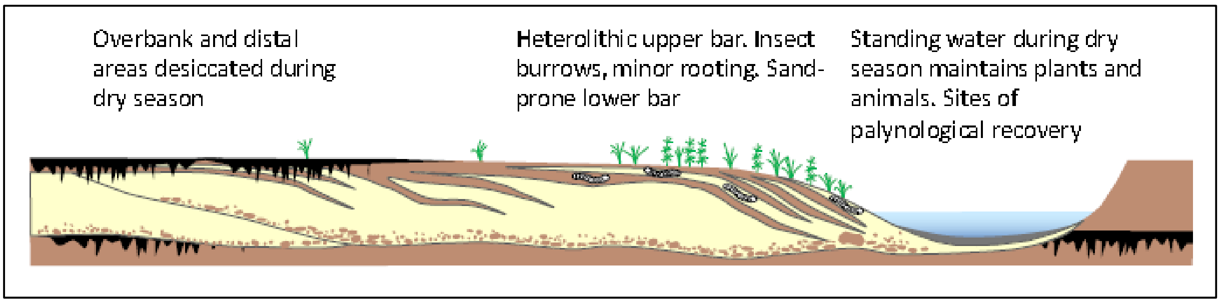


Figure 9: Skaggerak Depositional Environment

2.1.3 Depositional Model

Regional mapping of the facies distribution during deposition of the Judy Sandstone Member (Figure 10) highlights the context of the fluvial systems within the Acorn area. Typically, the setting of the Skagerrak is placed within the confines of the Central North Sea, with the adjacent Southern Permian Basin regarded as a separate entity because of the marked facies change to Muschelkalk marine limestones and the marginal marine Dowsing Dolomitic Formation. However, detailed facies mapping, based on a horizon slice c. 10 m below the Muschelkalk Halite (a robust regional Illyrian marker) extends the palaeogeography of an interval broadly equivalent to the upper part of the Judy Formation and prior to the early Ladinian onset of Julius Mudstone deposition. This reveals the extension of clastic mud and very minor sandstone as a lobate body, immediately down-palaeoflow from the Judy fluvial systems (based on palaeocurrent data documented in McKie, 2011), terminating in coastal sabkha and (rarely) lignite-bearing mudstones. The Skagerrak river systems appear to have deposited a large part of their sand load in the approach to the Mid North Sea High region, where palynological data indicate episodic march conditions (cf. Goldsmith et al. 1995), prior to extending as muddy streams into the SNS. These muddy streams diluted the marine Muschelkalk carbonates, accounting for the lithological transition into the Dowsing Dolomitic Formation. In nearby well 29/3b-4 stacked coarsening upward cycles of climbing current ripple laminated sandstones suggest the episodic development of small-scale deltas that prograded into restricted water bodies.

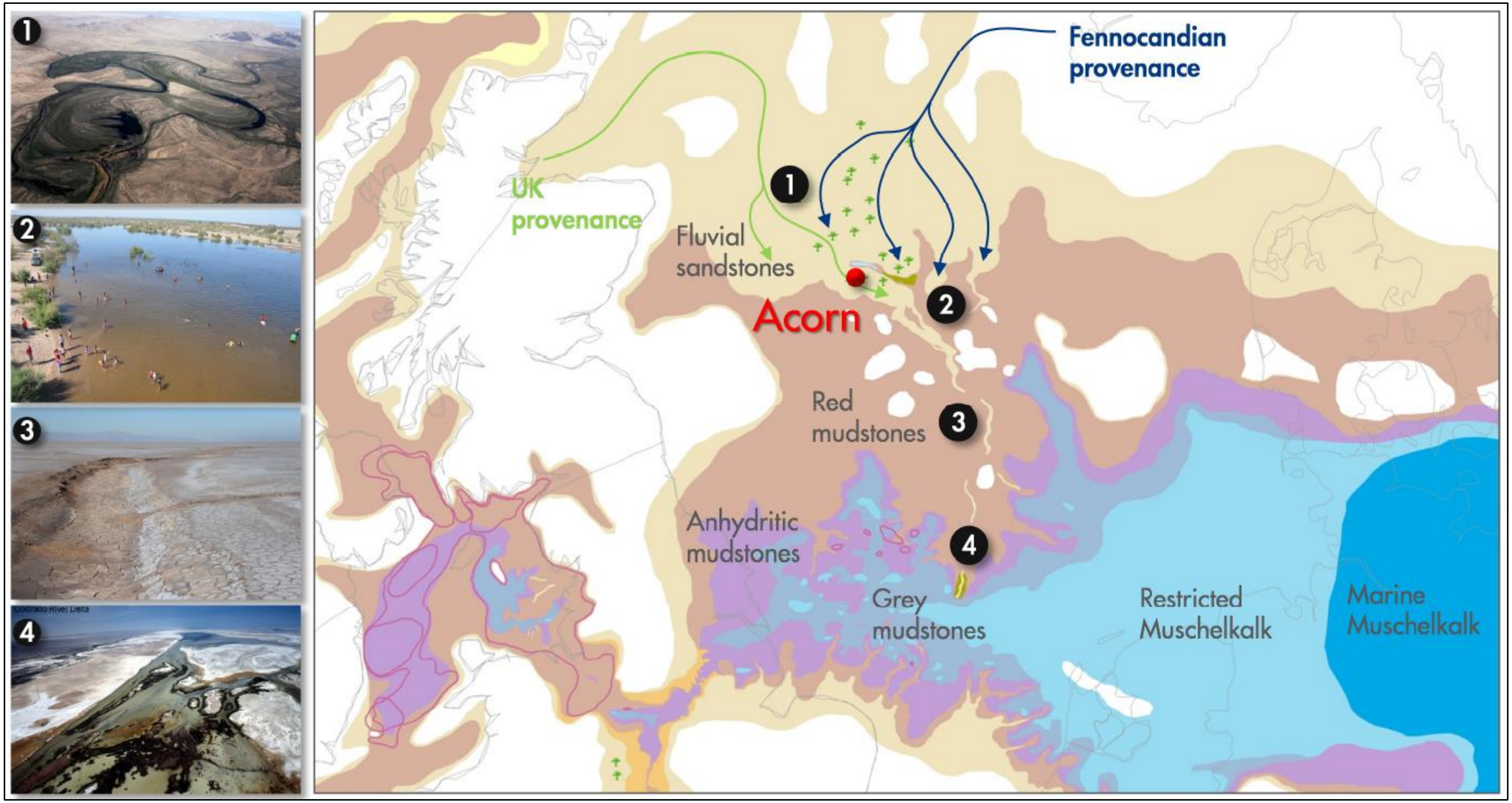


Figure 10 Gross depositional setting of the Late Anisian upper Judy Member with the Colorado River used as an illustrative modern analogue for various points (1-4) along the Skagerrak drainage.

2.2 Seismic Interpretation

2.2.1 Objectives and Approach

Acorn North is a Skagerrak discovery, with two well penetrations, and a significant volume of oil in a fairly structurally simple Triassic "pod" (fault block). Workshops between Shell and ExxonMobil in June 2014 identified the need for a detailed mapping effort, utilising all of Shell's in house reprocessing expertise to extract the maximum possible from the seismic data.

Objectives were as follows:

- Frame Acorn North in a Regional Context with **regional mapping**
- Create a robust **fault network** for input into the modelling phase of the project
- Create a **"Top Reservoir"** interpretation
- **Seismic Facies** Mapping to identify any non-Skagerrak facies

Work was carried out in June - August 2014, using optimised volumes of the 2010 TOMO ML dataset. A sense check of the interpretation was conducted in April 2015, versus the 20015 CGG Broadseis data, and is detailed further in the seismic interpretation report. It was found that while subtle imaging uplift was available with the 2015 data, the overall findings remain the same and the products generated in summer 2014 are robust enough for this project stage.

All mapping was done in Petrel, while well ties and depth conversion were performed in NDI.

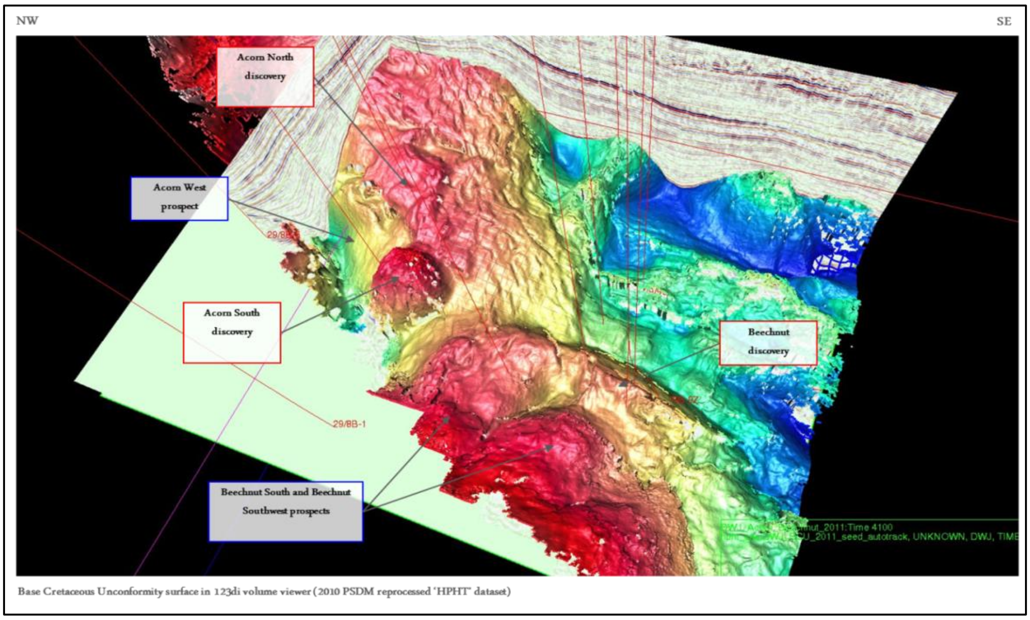


Figure 11 Location of Acorn N Triassic Pod in relation to Beechut (BCU Map, 2011 Shell interpretation)

2.2.2 Seismic Database

All of the available seismic datasets provide coverage over Acorn North. At the time the seismic interpretation was being carried out the TOMO ML reprocessing was not available. The seismic interpretation of Acorn was therefore carried out on the conventional 2010 HPHT cornerstone dataset.

The seismic data below the Base Cretaceous Unconformity (BCU), particularly over the interval of interest, is badly affected by multiples and loss of seismic band width. In order to aid the seismic interpretation in this challenging zone several different seismic cubes were generated using various post-processing techniques. These cubes were used along with the normal reflectivity to help mitigate against the interference of multiples and loss of band width.

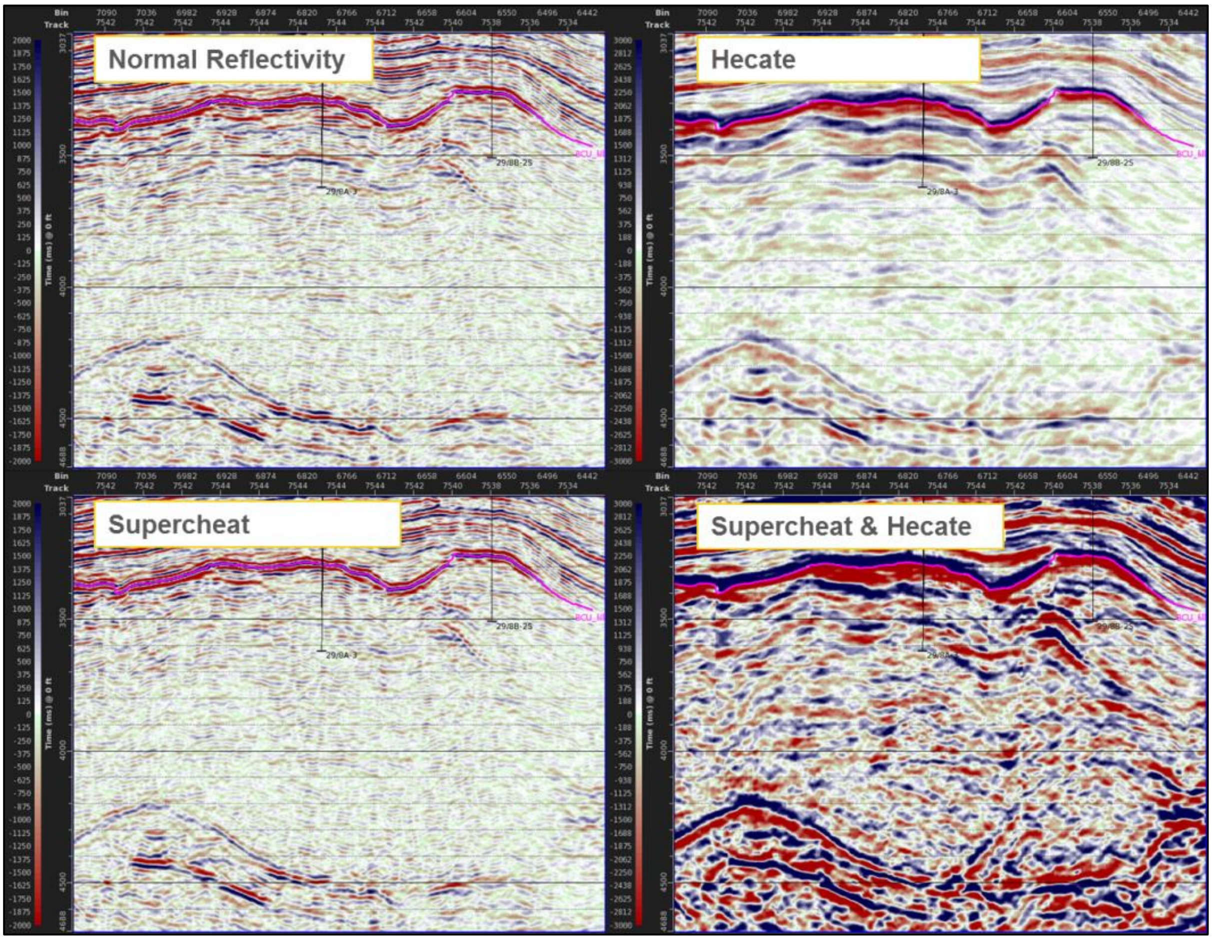


Figure 12 Optimised 2014 seismic volumes vs. 2010 HPHT data, Acorn

All of the various cubes were used in order to carry out the seismic interpretation over Acorn North. The normal reflectivity cube with AVC applied was the reference volume for interpretation and used in conjunction with the other volumes.

The TOMO ML and Broadseis data also covered Acorn North but were delivered after the seismic interpretation took place. The interpretation was checked against these datasets to ensure that they were consistent and assess whether or not the new processing and acquisition provided a change in the seismic interpretation. No significant differences were observed and the surfaces from the HPHT dataset that were used in the modelling remain the final surfaces.

2.2.3 Well Ties & Picking Philosophy

There are two wells on Acorn North, one vertical well (29/8B-3) and one deviated (29/8B-6) through the reservoir interval. The vertical wells have the best coverage of sonic and density logs, with data from shallow intervals, to the interval of interest (T Kimmeridge Clay to B Skagerrak) and below. This well provided the main seismic to well tie for Acorn North, defining the picking philosophy for each of the key horizons. In addition to this well ties from some offset wells were used to assess the consistency in the pick and check for any polarity switches.

The seismic interpretation of Acorn North was carried out on the conventional HPHT dataset and Figure 13 shows the respective well tie at both the Acorn North well, 29/8A-3 and one offset well, 29/8A-4. In both wells there is a strong correction and reasonable match between the synthetic and the seismic.

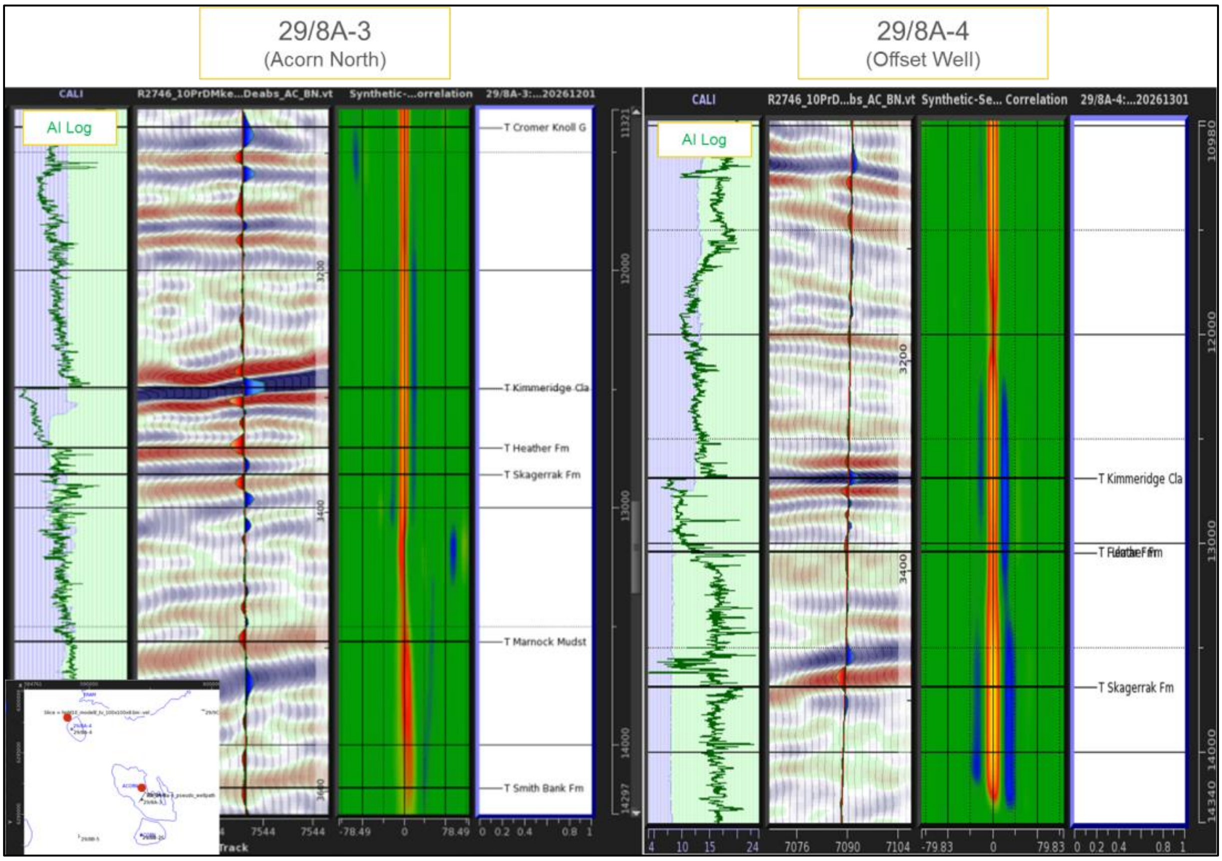


Figure 13 Final Seismic to Well Ties against the Conventional HPHT seismic for 29/8A-3 and 29/8A4, both generated using Butterworth synthetic wavelets

The overburden horizons (Top Kimmeridge Clay & Top Heather) are consistent across the well ties and result in a relatively conventional picking philosophy.

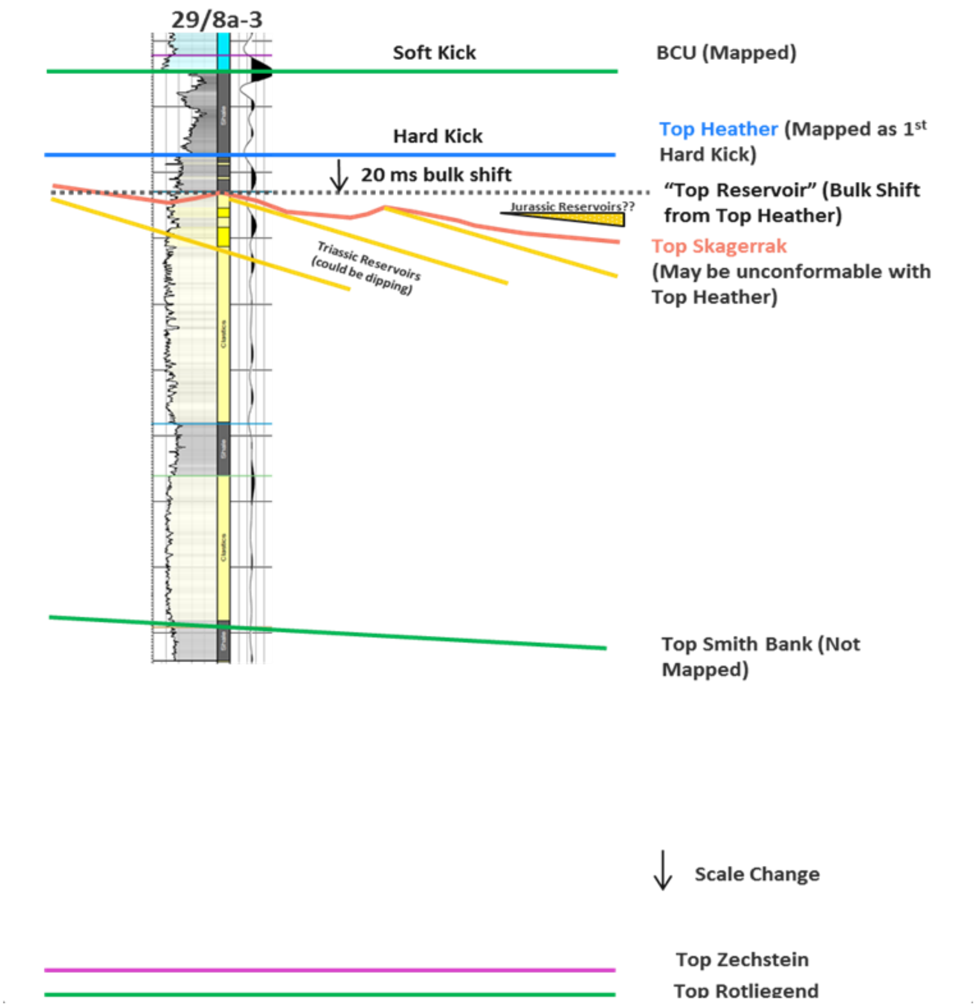
- Top Kimmeridge Clay: Peak – interpreted on reflectivity cube
- Top Heather: Trough – interpreted on Hecate Cube as zero-crossing.

The acoustic impedance (AI) logs demonstrate that the Top Skagarrak (Top Reservoir) has little to no acoustic impedance contrast with the overlying Jurassic Heather Formation. This made it extremely challenging to map it out directly and as a result required the overlying Top Heather horizon to be bulk shifted to approximate Top Skagerrak. It should be noted that away from well control there is potential for error, if the Jurassic section thins or thickens, using this method.

The picking philosophy for Acorn North was as follows:

- Map gross structure – particularly deeper salt features and major bounding faults
- Map Base Cretaceous Unconformity (BCU/T Kimmeridge Clay) - regional soft kick
- Map Base Kimmeridge / Top Heather - regional hard kick
- Bulk shift down Top Heather to approximate Top Skagerrak.

The overall picking philosophy was checked against well ties corresponding to the TOMOML and Broadseis data, with no changes required.



Surface	*Pick*	*Comment*
BCU	*Reflectivity – PEAK (Soft Loop)*	
Top Heather	*Hecate – S CROSSING*	*Pseudo – impedance pick- hard kick*
Top Skagerrak	*None*	*Bulk Shifted*
Top Zechstein	*Reflectivity – S CROSSING*	*Interpreted some phase rotation*
Top Rotliegend	*Reflectivity – S CROSSING*	*Interpreted some phase rotation*

Figure 14 Summary of Mapped Horizons - Acorn Skagerrak Play

2.2.4 Structural Interpretation

Regional

Beneath Acorn North two major fault Rotliegend trends can be identified, N-S and NE-SW. These faults detach in the Zechstein Salt, however the trends re-establish themselves above the salt once more at reservoir level. The Acorn North area has a major salt diapir underpinning Acorn South, and two smaller diapirs within the Acorn North field.

Acorn North developed as a raised fault block around the major Volgian - Early Cretaceous rift phase in the basin. By the time of Top Cromer Knoll deposition at the end Albian, the area was tectonically quiescent and has remained so to the present day. Figures detailing this evolution can be found in the seismic interpretation report.

Acorn North Skagerrak

Mapping of the Skagerrak level structure was undertaken iteratively, with a fault framework being mapped at the same time as Base Kimmeridge. A robust fault interpretation has been developed with support from structural attributes, in particular the variance cube. The fault geometry is influenced by salt tectonics, with curved shapes adapting to radial stress fields around salt bodies. Confidence in the fault interpretation is good at top reservoir level, but model-driven at depth.

The final “Top Reservoir” map contains a distinct N-S trending structural crest, into which the discovery and appraisal well were drilled. There is a further shallow area to the north. A major graben exists just to the east of the discovery wells. While care was taken to map all resolvable faults, it is possible that there are many further faults <75ft throw that could not be imaged. Given the thin nature of the channel sand bodies in the reservoir, this has major implications for connectivity and is further explored in the dynamic modelling section of this report.

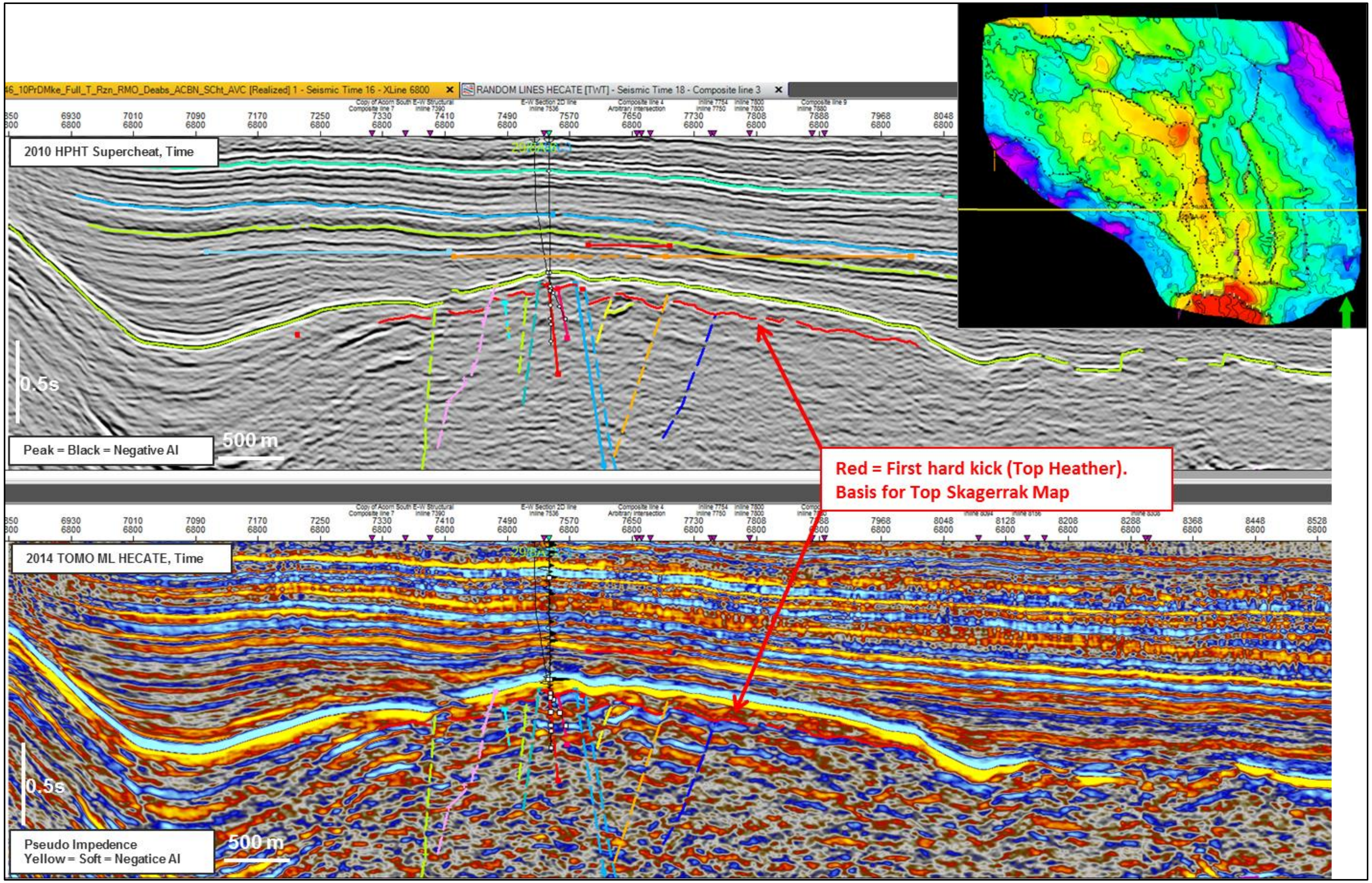


Figure 15 Interpreted "First Hard Kick" (Skagerrak Top Reservoir Proxy) over Acorn N Central Area. Note good shallow fault imaging, with image deterioration with depth

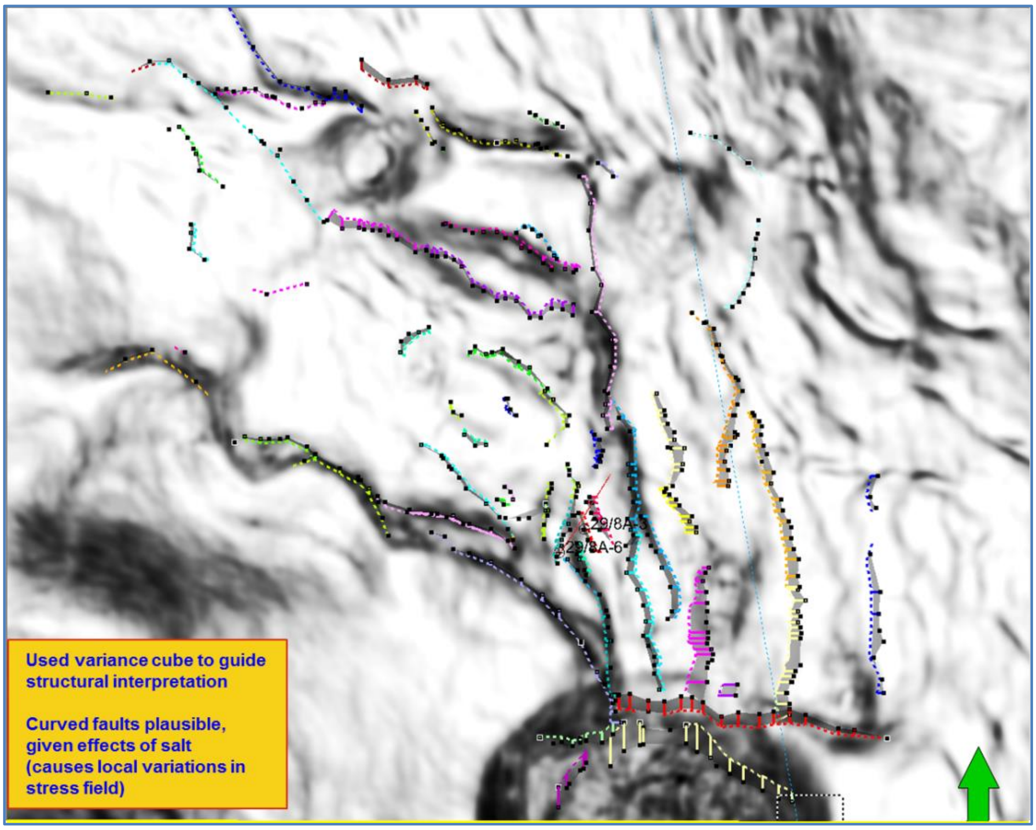


Figure 16 Use of Variance Cube to Guide Acorn N Fault Interpretation. Timeslice at 3380ms

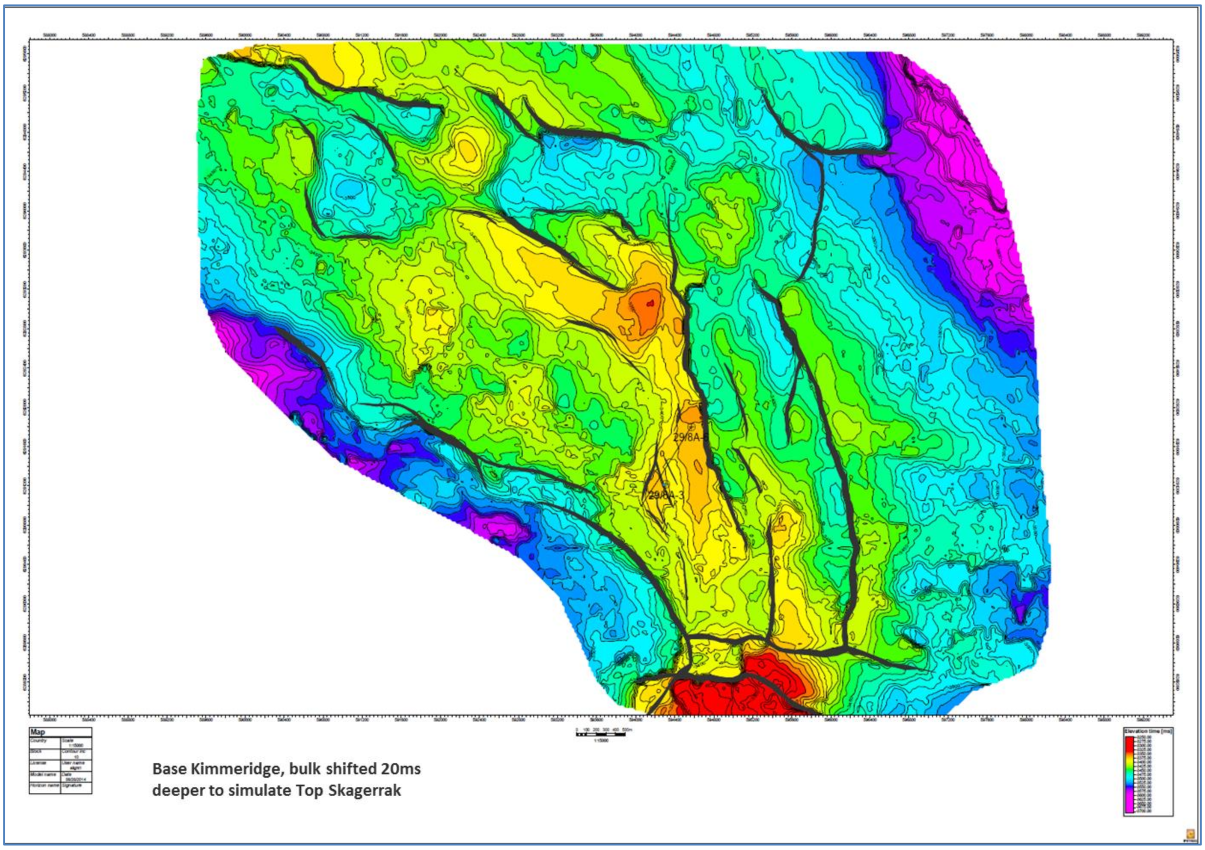


Figure 17 Final "Top Reservoir" TWT. Note N-S trending crest, into which A3 and A6 wells were drilled. CI = 25ms

2.2.5 Reservoir Interpretation

Six seismic facies could be found in the field area. The most common seismic facies was a "Skagerrak Type". Most of the Acorn N block was composed of this seismic facies, which could be tied to the 29/8A-3 and 29/8A-6 wells. The south west fringing area had a "Jurassic Wedge" type seismic facies, with a prominent reflector that could be tied to the 29/8A-4 well in the northwest of the field area.

There were four more unusual seismic facies, which seemed linked to local salt tectonics). Of these, the high amplitude facies found in the graben to the east of the discovery well was most critical to understand, as it fell into the "Top Reservoir" closure area. This is interpreted as a Jurassic aged salt-withdrawal graben, with high amplitudes attributable to shallow detached salt. The fill of this graben has no well control. It is proposed that rather than a typical shallow Skaggerak, this graben could contain an expanded Heather section.

The majority of the Acorn North area has Skagerrak seismic facies. These areas of Skagerrak form the discovered volume of Acorn North, and the near field exploration prospect Acorn East. The "Jurassic Wedge" to the southwest forms the Acorn South West prospect.

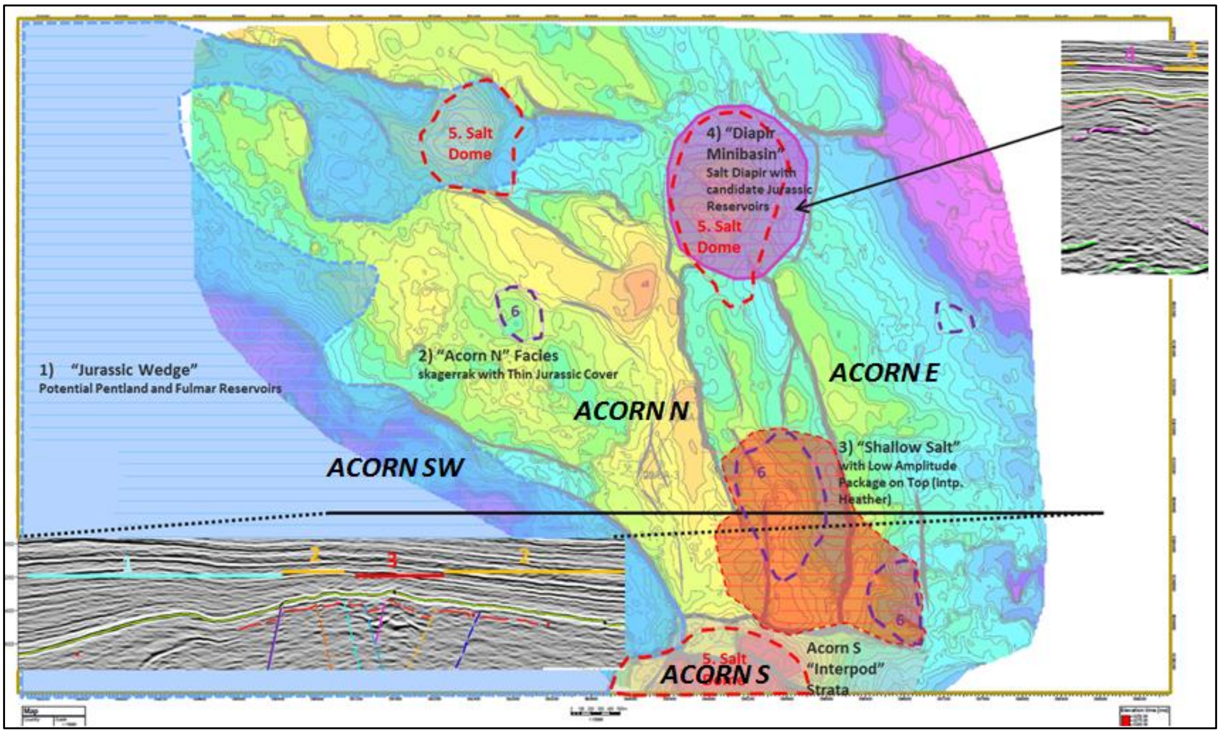


Figure 18 Seismic Facies Interpretation Summary. Not the area of seismic facies 3, interpreted as shallow salt with Jurassic shale fill, dividing Acorn North and Acorn East

2.2.6 Depth Conversion

A velocity model over Acorn North was required to depth convert the Top Heather time interpretation for the following reasons:

To generate Top Reservoir (Top Skagerrak) by bulk shifting the Top Heather Surface by the average thickness of Heather observed in the two Acorn wells.

To be used in the Model Building for Acorn North only.

To test the productivity of Acorn North in advance of completion of seismic interpretation over the whole block

Analysis of sonic logs over the area indicated that a four layer velocity model would appropriately capture the velocity trends observed in the logs. Two different methods were tested over Acorn North to try and capture the trends observed and generate a velocity model:

PSDM Velocity Model combined with constant interval velocity

Linear V0k Model

The linear V0k method resulted in a four layer model, however using a PSDM velocity model with constant velocities captured the trends in a simpler model with only three layers. The HPHT PSDM velocity model, once scaled, appropriately represented the velocity trends observed from the surface down to BCU, without having to split the layer into two

The uncertainties associated with the key horizons are summarised in Table 2. Top Reservoir was generated by bulk shifting the Top Heather surface down by the average thickness observed in the wells (106 ft), resulting in the same depth uncertainty as the Top Heather.

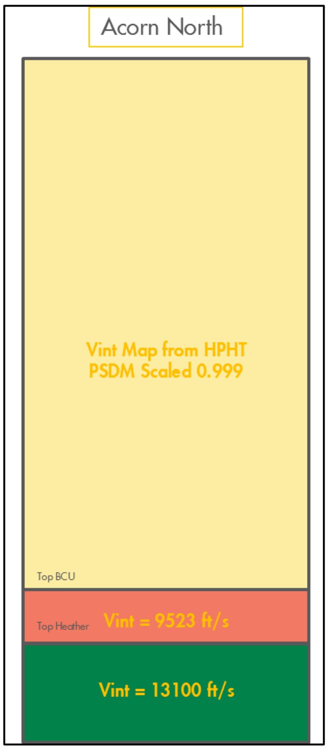


Figure 19 Summary of Final Velocity Model for Acorn

Table 2 Summary of Depth Uncertainities for Acorn North

Horizon	1 sd (ft)	2 sd (ft)
BCU	55	110
Top Heather	70	140
Top Reservoir	70	140

Final depth surfaces were tied in Petrel using an influence radius of 1000m.

2.3 Petrophysics

2.3.1 Objectives and Approach

This section summarises the petrophysical study for the oil bearing Skagerrak formation in Acorn North carried out in 2014 and 2015. There are two wells, 29/8a-3 and 29/8a-6, the former was drilled in 1985 by Shell / Esso, and was tested with three DST's. Core was cut in the Skagerrak and the well was logged with Schlumberger wireline including formation pressures. The second well, 29/8a-6, was drilled in 2009 by Venture / Centrica, it is a highly deviated well with an extended well test in the Skagerrak. The well was logged with Pathfinder LWD and a Baker Hughes LWD NMR.

The objective of the study was to provide the petrophysical properties and uncertainties to the static and dynamic modelling for Acorn North. This includes volume of shale, porosity, electro facies, permeability and hydrocarbon saturation logs, as well as to create a saturation height function. The implementation of the logs in the static model and the upscaling checks are confirmed in a close the loop exercise.

Although the wells had both been interpreted separately, an in-depth, integrated study had not previously been carried out. Therefore, the objective of the study was to build a consistent petrophysical interpretation. The petrophysical interpretation challenges include:

- Differing tool suites and technology used in each well.
- Uncertainty on the water properties as no sample has been acquired.
- The two wells have previously been calculated with very different porosity values, therefore the quality of the logs and interpretation was checked.
- Integration of the NMR log into the interpretation

2.3.2 Reservoir Units

The reservoir focus of this study is the oil bearing Triassic clastic Judy Skagerrak.

2.3.3 Data Available

29/8a-3 log availability

29/8a-3 was logged by Dresser Atlas wireline, Figure 20 shows the log availability by hole section, note that the sonic wrap display is shown in black. The Skagerrak is highlighted in the 8 3/8” section.

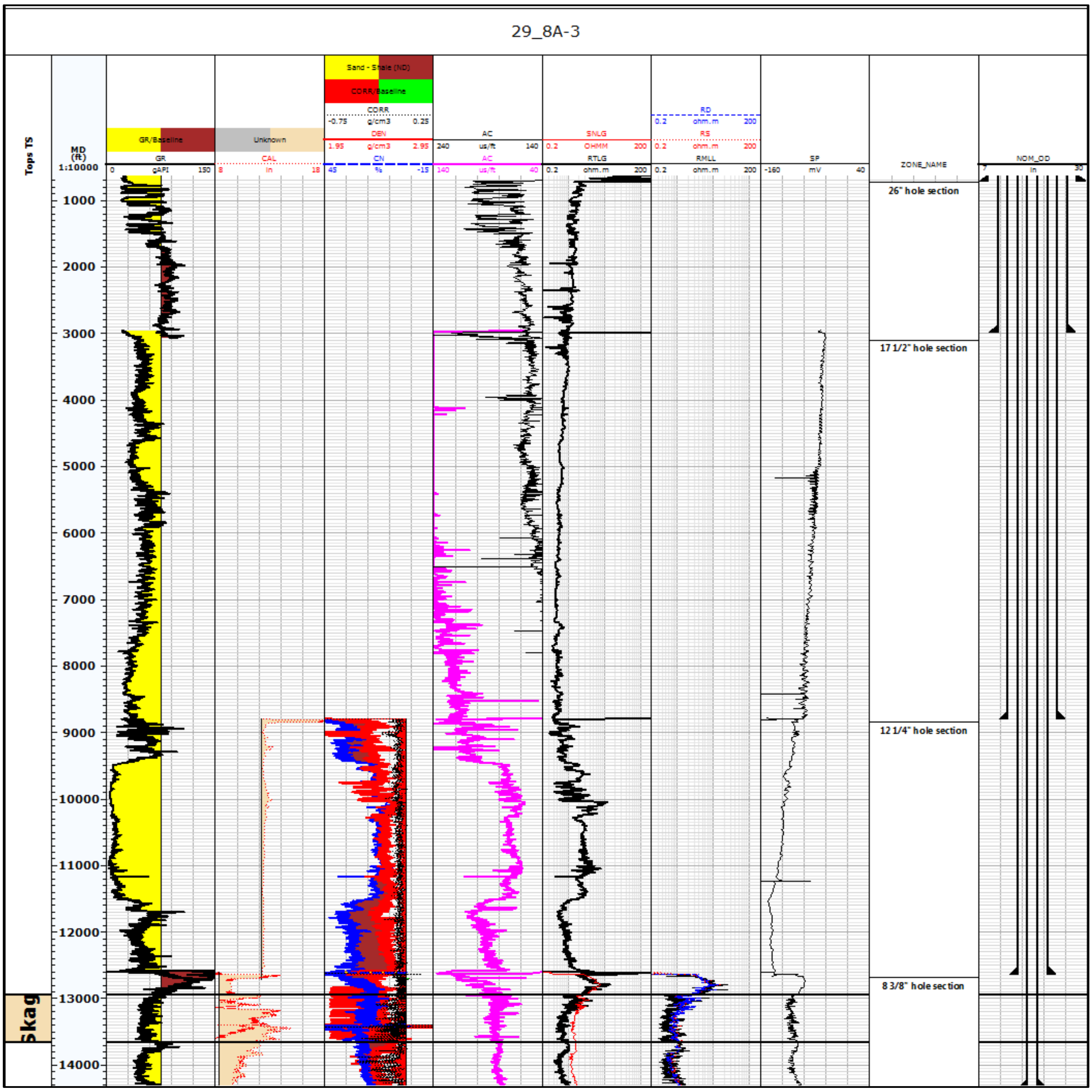


Figure 20 29/8a-3 Log Data

29/8a-6 log availability

29/8a-6 was drilled and logged in 2009, all logging was run on LWD and the majority of the data was provided by Pathfinder, the Baker NMR tools run in the 8 ½" hole section were run in memory only mode piggybacked on the Pathfinder tool suite. Due to the nature of LWD where memory data in time is spliced with time-depth data recorded while drilling there remains some depth matching issues between the NMR Baker data and the rest of the Pathfinder LWD data. All depths in this report are referenced to the Pathfinder LWD data.

The 8 ½" section was drilled and logged in four bit runs, there were three different BHA / tool configurations run and therefore some data has been acquired in wash down mode. The data acquired in wash down passes quality checks but it was acquired at the upper end of the acquisition system capability and therefore is not as reliable as the while drilling data.

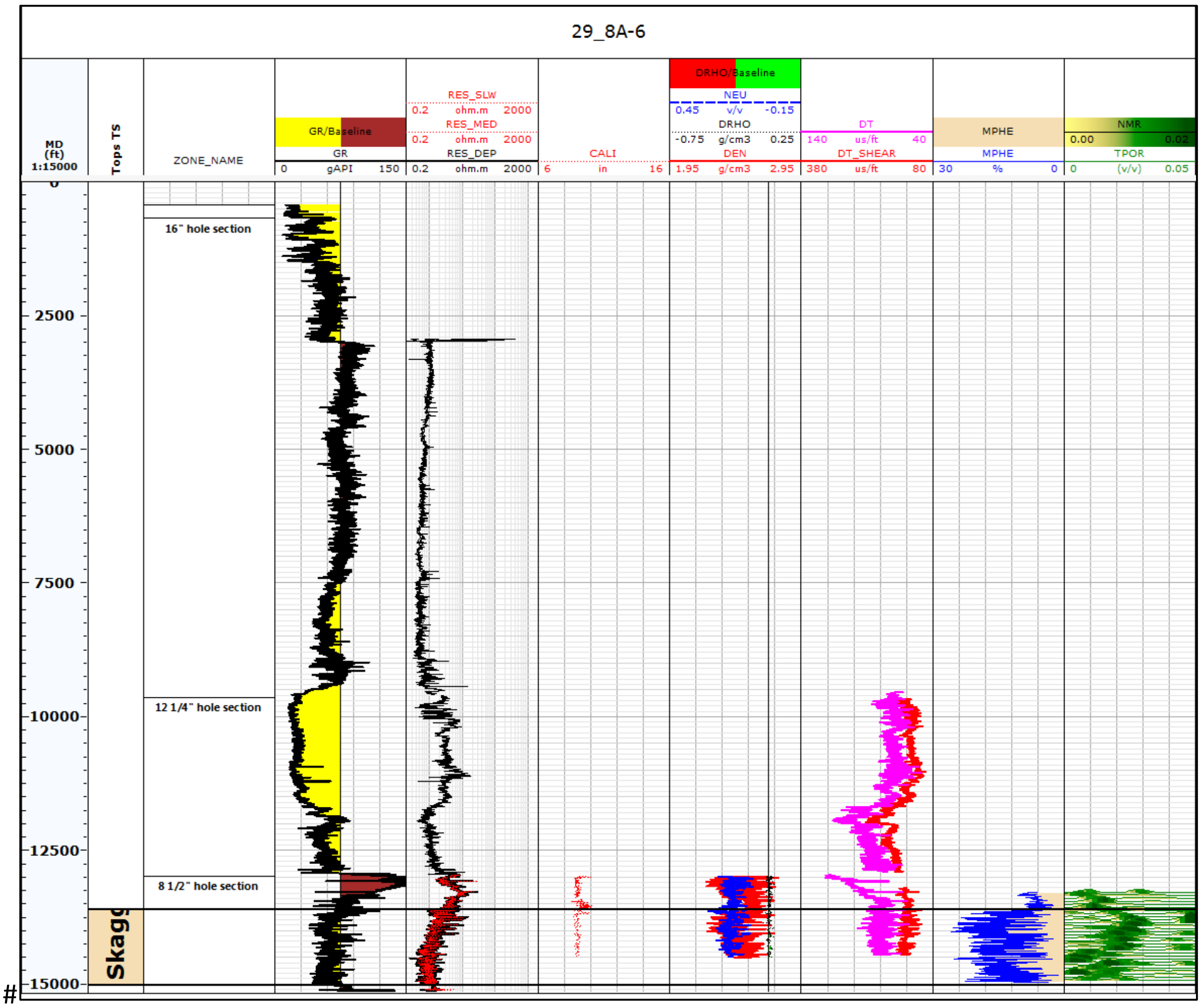


Figure 21 29/8a-6 Log Data

2.3.4 Temperature Depth

Using the regional CNNS trend, which fits other fields very well, a reservoir temperature of 320 degF with a normal distribution and standard distribution of 10 degF has been used in Acorn North.

2.3.5 Overburden Calculation

The overburden stress was calculated as per the Schutjens/Hakvoort method in the revised cookbook. The isostatic stress is defined as a function of maximum and minimum horizontal stress, vertical stress and pore pressure. In the absence of other information the maximum and minimum horizontal stresses are assumed to be equal and as a factor K times the vertical stress.

To calculate vertical stress, a typical value for the average overburden density was used = 2.3 g/cc (= 1 psi/ft) resulting in vertical stress = 13,200 psi for the reference case. A pore pressure value of 10,997 psi was used and K = 0.9.

Therefore, a base case mean effective isostatic stress has been calculated to be **1,323 psi** at **13,200 ft TVDSS**

2.3.6 Routine and Special Core Analysis

Three cores were cut in 29/8a-3 with 96% recovery. Routine and special core analysis was carried out and the tests conducted are summarised in Table 3 below.

Table 3 Core Measurements 29/8a-3

Report Number	Measurement
EP200806203902 Conventional Core Analysis	Surface core gamma ray
	Fluid saturations and Summation of Fluid Porosity – method no longer used in Shell
	Air perm (horizontal at 1' intervals)
	Air perm (vertical at 10' intervals)
	Gas Expansion Porosity
	Grain Density
	Brinell Hardness Measurements
EP201407233761 Special Core Analysis	Permeability to air
	Helium injection porosity
	Grain density
	Formation resistivity and resistivity index
	Formation factor as a function of overburden pressure
	Air-brine capillary pressure (Cell method)
	Mercury injection (drainage and imbibition)
	Permeability to brine as a function of overburden pressure
	Porosity as a function of overburden pressure
	Cation Exchange Capacity
EXPRO200306910390	Irreducible water saturation on three samples (Dean Stark)
EP201407233728	Thick walled cylinder strength
EP201407233728	Acoustic transit time
	Porosity (ambient and 240 bar
	Matrix density

2.3.6.1 In-situ porosity correction

Porosity measurements at increasing hydrostatic confining pressures were analysed on core plugs from the Acorn 29/8a-3 well. Plug measurements were performed at five hydrostatic confining pressures (15, 1500, 2000, 3000, and 4500 psi).

The effective isostatic stress in the reservoir is calculated as being 1,323 psi, the porosity reduction to this stress is calculated as being 0.95 and is shown in Figure 22.

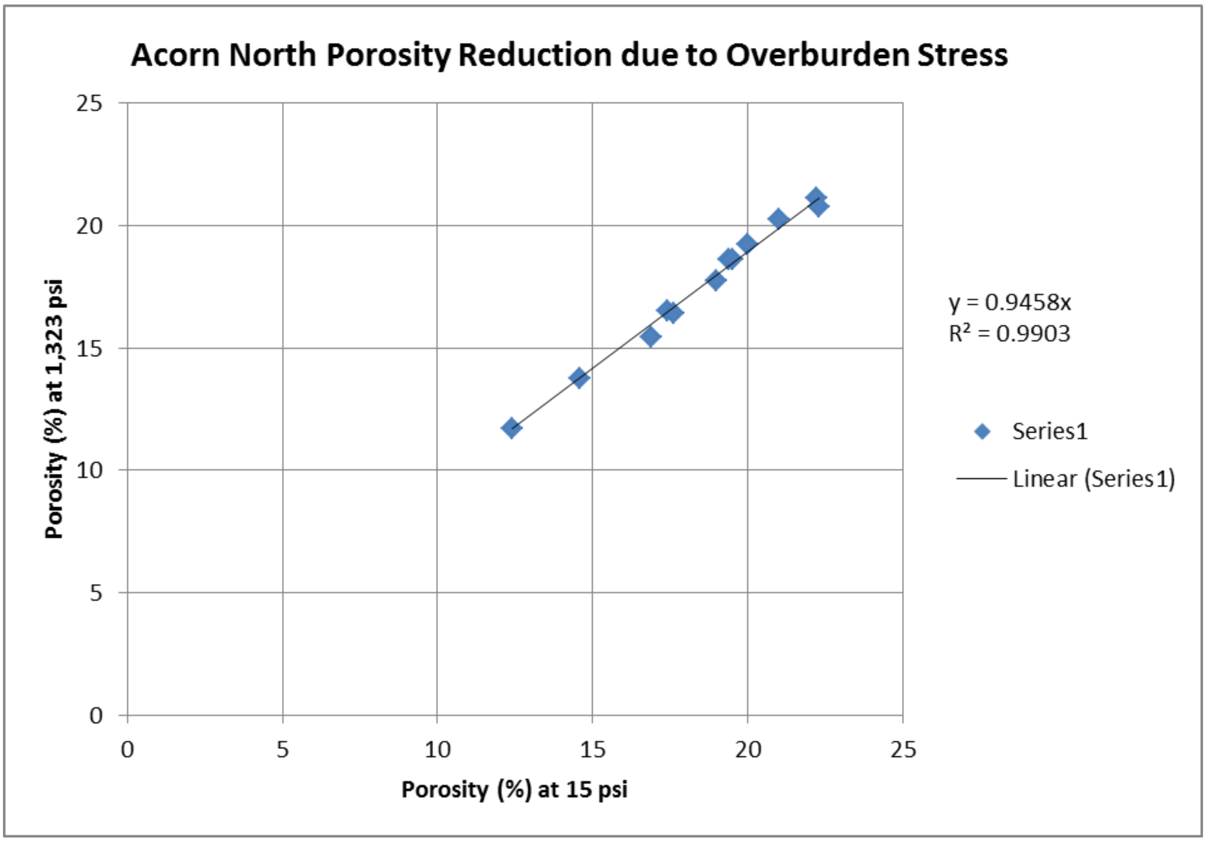


Figure 22: In-situ porosity reduction under isostatic stress

Therefore the ambient core porosity can be reduced to in-situ conditions using Equation 1:

$$CPOR_{in-situ} = CPOR \ \times 0.95$$

Equation 1: Core porosity stress correction

2.3.6.2 In-situ permeability correction

Permeability measurements were made at increasing pressures on 8 plugs in 29/8a-3. By individually fitting trend lines to the 8 core samples the brine permeability for each plug has been calculated at the in-situ stress of 1,323 psig. The black line in Figure shows the best fit equation to calculate brine permeability at in-situ stress conditions from air perm data at 200 psig (the green line is a y=x line). As can be seen the best fit line crosses the y=x line and therefore a condition has been applied to the stress correction. This equation and condition are given in Equation 2 and this has been applied to the conventional and special core analysis data.

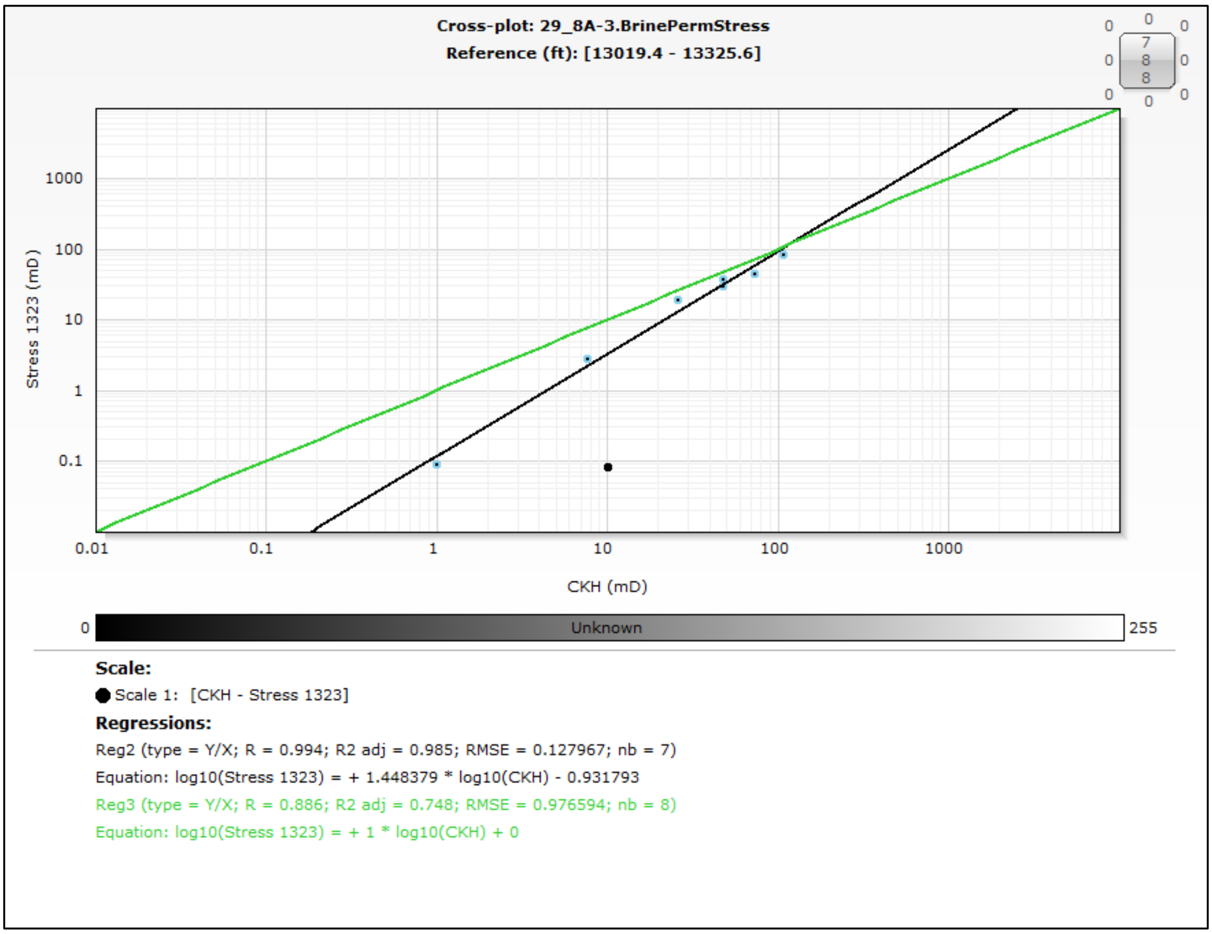


Figure 23: In-situ stress correction of core permeability

$$log10(CKH - C) = 1.4484 * log10(CKH) - 0.9318$$

$$MIN(CKH - C, CKH)$$

Equation 2: To stress correct air permeablity data to insitu brine permeability

2.3.6.3 Formation resistivity factor, m and m*

Formation resistivity factor was measured on each of the 12 plugs, the FRF was measured at increasing confining pressure and the formation water salinity corrected FRF* was calculated. The m and m* values at 1,323 psi overburden pressure for Acorn North was then extrapolated from the data.

	m	m* at salinity in ppk NaCl eqv			
Confining pressure	-	80	170	200	250
1323	1.92	1.94	1.93	1.93	1.93

Table 4: m and m* from SCAL in 29/8a-3

In the interpretation with formation water salinity of 80 ppk NaCl eqv the m* value to be used is 1.94 with a standard deviation of 0.01. The standard deviation is calculated from the range of m* numbers as formation water salinity varies.

2.3.6.4 *Resistivity Index, n and n**

Resistivity index data exists for 12 plugs from the 29/8a-3 core and the data was analysed. The data was then corrected for formation water resistivity and n* was interpreted for each plug.

	n	n* at salinity in ppk NaCl eqv			
		80	170	200	250
Stdev of ind plugs	**0.154**	**0.252**	**0.193**	**0.188**	**0.181**
All data	**2.012**	**2.117**	**2.072**	**2.068**	**2.061**

Table 5: n and n from SCAL in 29/8a-3*

In the interpretation with formation water salinity of 80 ppk eqv the n* value to be used is 2.12 with a standard deviation of 0.25. The standard deviation is taken from the individual plug n* values at 80 ppk NaCl eqv.

2.3.7 Volume of Shale – Acorn North

A volume of shale was calculated from gamma ray and density neutron cross plot, the minimum of the two calculated values was then used in interpretation.

	29/8a-6	29/8a-3	Unit
GR_matrix	44.8	35.6	gAPI
GR_shale	87.8	74.8	gAPI
RHOB_matrix	2.61	2.66	g/cm3
RHOB_shale	2.57	2.59	g/cm3
RHOB_fluid	1	1	g/cm3
NPHI_matrix	-0.03	-0.03	v/v
NPHI_shale	0.20	0.23	v/v
NPHI_fluid	1	1	v/v

Table 6: Shale volume parameters

2.3.8 Formation Resistivity

Due to differing logging conveyance methods and physics of the tools run in the two logged wells in Acorn North the resistivity curve to be used in interpretation was confirmed.

In 29/8a-3 both induction and laterolog tools were run in water based mud, technically the laterolog is more suited to the environment but the induction tool was run a week earlier than the laterolog and the hole conditions were degrading with time. The induction and laterolog curves are very similar. The LWD propagation wave resistivity tool run in 29/8a-6 is more analogous a measurement to the induction tool. Hence Table 7 indicates the formation resistivity curves used in interpretation.

Well	Formation resistivity curve description	Original curve name
29/8a-3	**Deep Induction**	**RTLG**
29/8a-6	**High frequency, long spacing, phase shift**	**RDPH**

Table 7: Formation resistivity curves

2.3.9 Water Salinity (Rw)

There are no uncontaminated water samples available in Acorn North and therefore the water salinity has to be evaluated from logs and analogues. Both 29/8a-3 and 29/8a-6 were drilled through the contact and logs exist in the water legs. Initial analysis, calculated a salinity range 170 – 200 – 250 ppk NaCl eqv.

The formation water salinities picked above ranged from 170 to 250 ppk NaCl, the initial evaluation was carried out with the base case at 200ppk and the uncertainty analysis covered the range picked above. Table 8 below shows the input variables to the petrophysical interpretation as a function of salinity.

Salinity (ppm NaCl)	Rw (ohm.m at 320 degF)	m* (at 1,323 psi)	n*	Formation water density at insitu conditions (g/cm3)
80,000	0.023	1.94	2.31	1.059
170,000	0.013	1.93	2.20	1.122
200,000	0.012	1.93	2.19	1.148
250,000	0.0105	1.93	2.18	1.180

Table 8: Salinity values and associated Rw, m and n**

However once facies analysis had been carried out and the high permeability facies only data is used in analysis the formation water resistivity interpretation changes to 0.023 ohm.m which is a salinity of 80 ppk NaCl eqv. Therefore, the petrophysics was revisited with this new insight. This lower salinity formation water interpretation reduces the risk of halite drop out in the event of water break through during production.

2.3.10 Qv Porosity relationship

In order to establish a relationship between Qv and porosity for use in Waxman Smits interpretation two data sources are available, namely the core data in 29/8a-3 and the NMR data in 29.8a-6. Porosity and saturation are calculated in PORSHDEN. The format for the Qv equation in PORSHDEN is given in Equation 3, where qvf and qvp are constants.

$$Qv = qvf * \emptyset^{qvp}$$

Equation 3: PORSHDEN format for Qv calculation from porosity

The data from NMR and core was plotted in a single cross plot. The green data points are from the NMR and the purple data points from core. This figure shows that the data is consistent and overlapping between the two data sources but that the regression through the core data is lower than the Qv regression in the NMR data. This is possibly due to sampling bias in the core data. The Qv relationship from NMR was used in this interpretation as the logs will have the same sampling as the NMR.

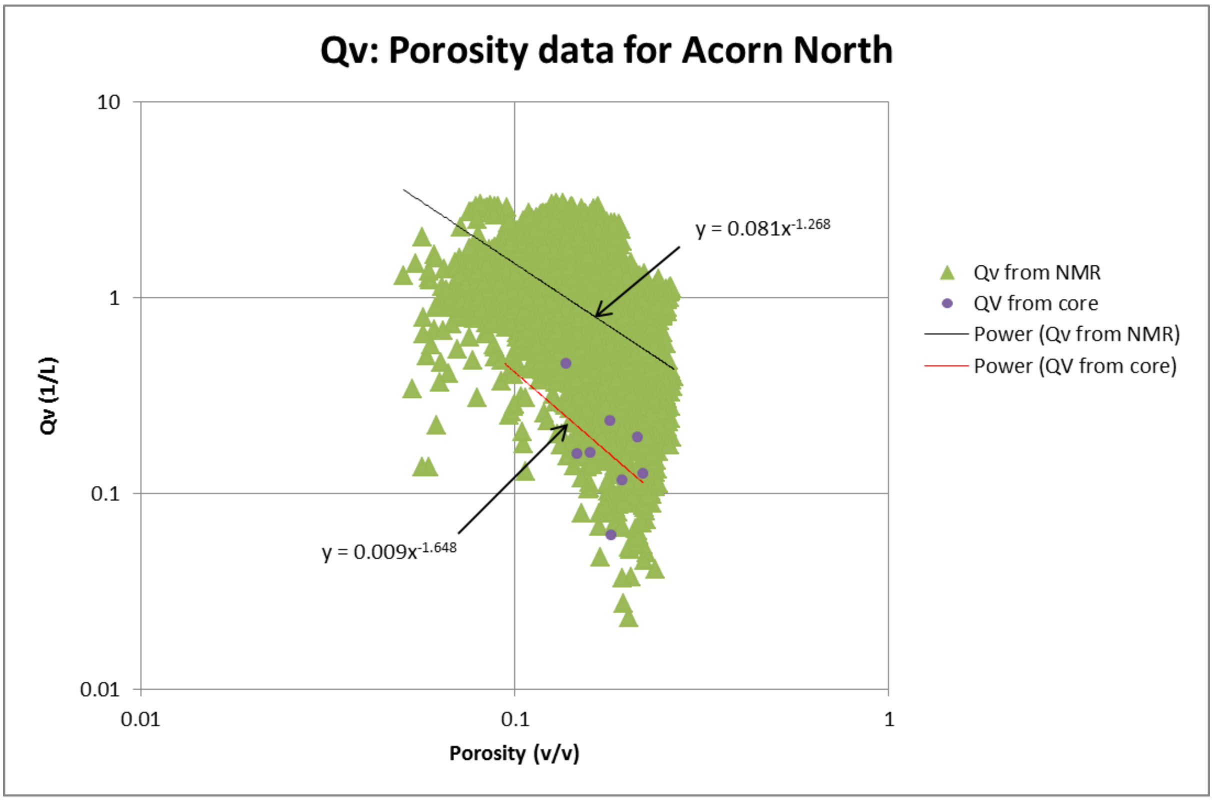


Figure 24 Qv: Porosity data for Acorn North

2.3.11 Porosity & Oil Saturation Evaluation (PORSHDEN)

PORSHDEN is an iterative interpretation method that calculates porosity and hydrocarbon saturation simultaneously from a density and resistivity log. This method, as applied in Acorn North, incorporates a matrix density that increases with decreasing porosity, a correction for fluid mix in the invaded zone and a clay content dependent on porosity. The hydrocarbon saturation is calculated using Waxman Smits. The B factor is determined to be 23 from the 1978 Waxman Smits chart at a temperature of 320 degF. The other inputs to the PORSHDEN script are previously described in this section.

Monte Carlo analysis incorporating the uncertainty in each of the input parameters showed that the uncertainty in Qv and n* were the two most significant factors in the water saturation calculation.

2.3.12 Electro-Facies

A neural network (Ipsom) was constructed in Techlog, to create five classes from the logs. The neural network was run in a non-supervised mode so that an electro facies is built. Fluid fill (flag) and formation resistivity were not included as the purpose of the neural network is to identify facies in the rock and not the fluids. The initial five facies were reduced to three facies as the geologic model called for non-net, background and high permeability facies. A permeability cut-off of 20 mD was applied to differentiate background from high permeability facies. It is recognised that of the inputs to the neural network that there are two main factors, porosity and volume of clay. Therefore, a cross plot of the volume of shale on the x-axis and the porosity on the y-axis is shown in Figure **Error! Reference source not found.**25 with the final facies in colour.

Table 9 Showing neural network to reduced facies

Mapped reduced facies	Facies description	VSh (relative)	Por (relative)
0	Non net	High	Low
1	Background	Low	Med
2	High perm	Low	High

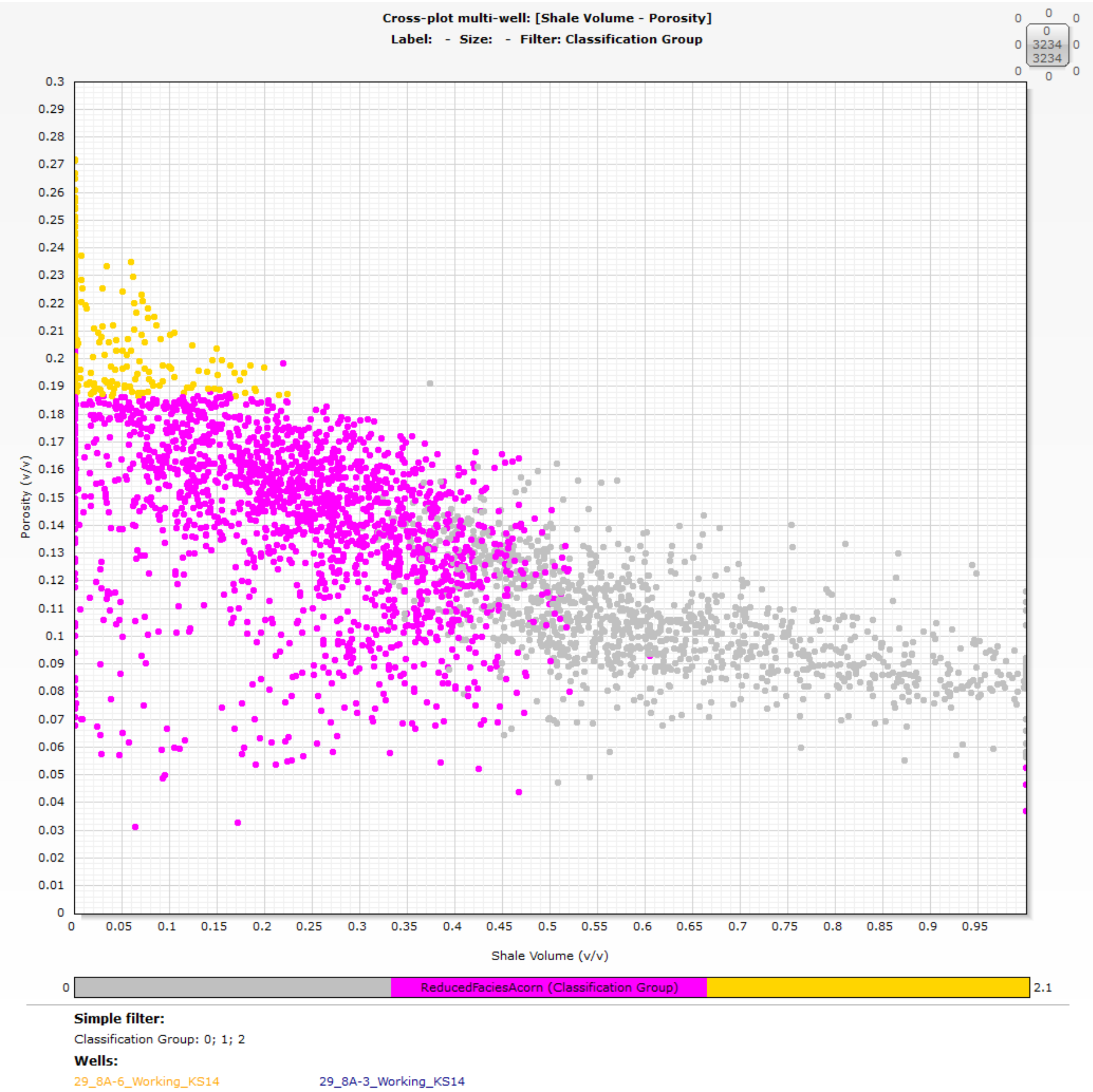


Figure 25 Reduced facies with permeability cut

In order to further explain the mis-match previously observed in the porosity between the two wells Figure 26 shows the distribution of facies per well. It can be seen that 29/8a-3 intersected 20% of high permeability sand and 29/8a-6 only intersected 8%. The contrast in distribution of the facies by well has driven the facies distribution in the static model.

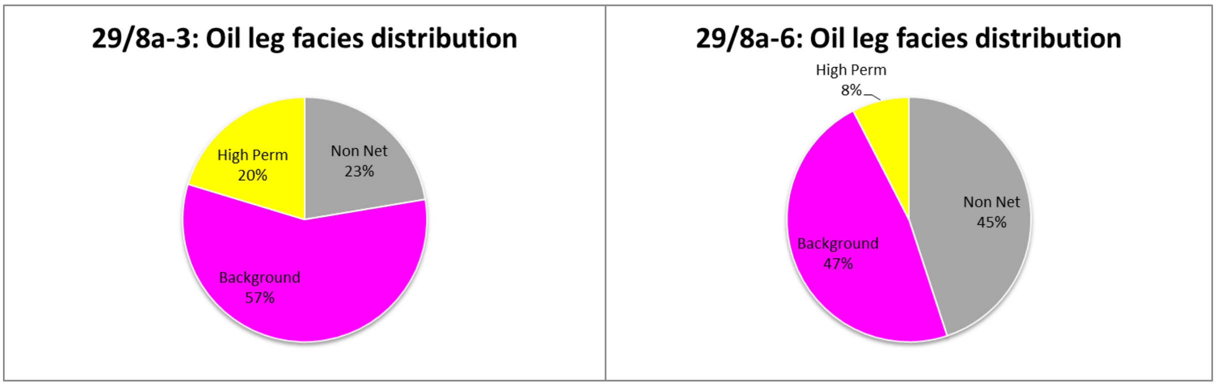


Figure 26 Facies distribution for each well in the oil leg

2.3.13 Permeability Evaluation

A porosity permeability equation has been built from the NMR data in 29/8a-6, the data overlaps with the core data from 29/8a-3 and due to the numbers of points can be more easily used for a facies based equation.

These regressions are geometric permeability as the high degree of compartmentalisation interpreted in the well test leads to the conclusion that high permeability streaks in well log data will not contribute significantly to the permeability in well test.

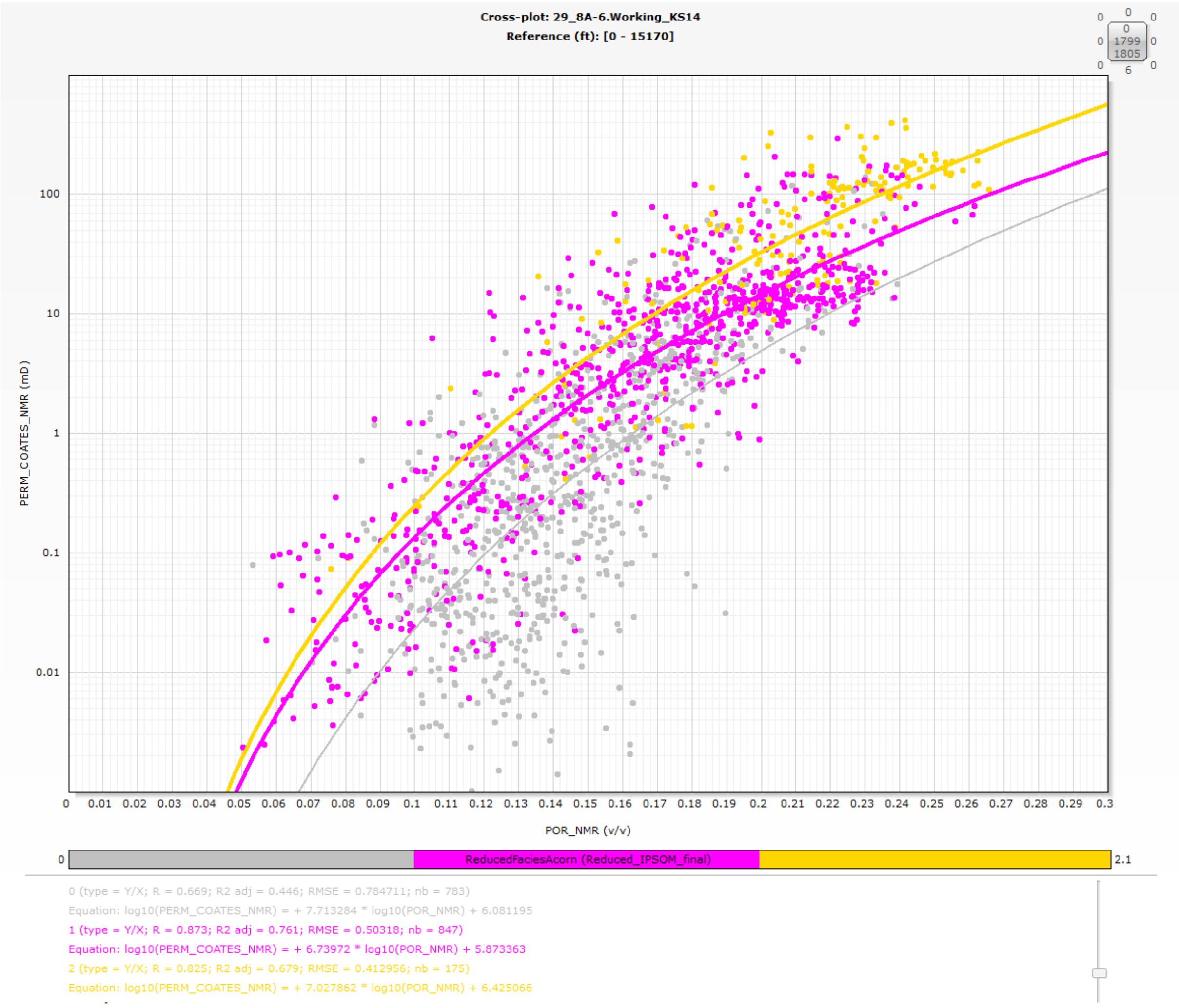


Figure 27 Permeability equations from NMR data acquired in 29/8a-6

$$Perm = 10^{a}\emptyset^{b}$$

Equation 4: Permeability from porosity in Acorn North

Facies	a	b
0	6.08	7.71
1	5.87	6.74
2	6.43	7.03

Table 10: Permeability equation parameters for Acorn North

2.3.14 Net Reservoir

Net reservoir has been calculated using two cut-offs, namely facies and porosity. The facies 0, having high volume of shale and low porosity was defined in the electro facies as being non-net. There is also a porosity cut off at 0.106pu. This is based on an average hydrocarbon por thickness of 95%.

2.3.15 Fluid Contacts

In the first well drilled in Acorn North, 29/8a-3, wireline formation pressures were acquired, these showed an oil gradient that matches PVT data and disconnected pressure points in the water leg. The contact was interpreted at 13,216 ftTVDSS from this FMT data combined with log interpretation and oil down to the bottom of the deepest DST which produced dry oil. The log interpretation and dry oil produced from the extended well test in 29/8a-6 lead to a similar depth for the contact and therefore the contact is taken to be the same in the two wells.

In the static model a single contact at 13,216 ftTVDSS is used with an uncertainty constructed as a truncated log-normal distribution with mean 13, 216 ftTVDSS, a standard deviation of 25ft, a minimum of 13,100 ftTVDSS and a maximum of 13,250 ftTVDSS.

2.3.16 Saturation Height Function

A saturation height function has been built using a Leveret J function from the mercury- air capillary pressure curves measured on the 29/8a-3 core.

$$Sw = 3.19\,J^{-0.29} \quad \text{where} \quad J = h\left(\sqrt{\frac{\kappa}{\phi}}\right)$$

Equation 5: Leveret J function for saturation height modelling

The cross plot of core J (x-axis) vs Sw (y-axis) in Figure 28 for all the data points shows a good fit between the calculated function and the input data.

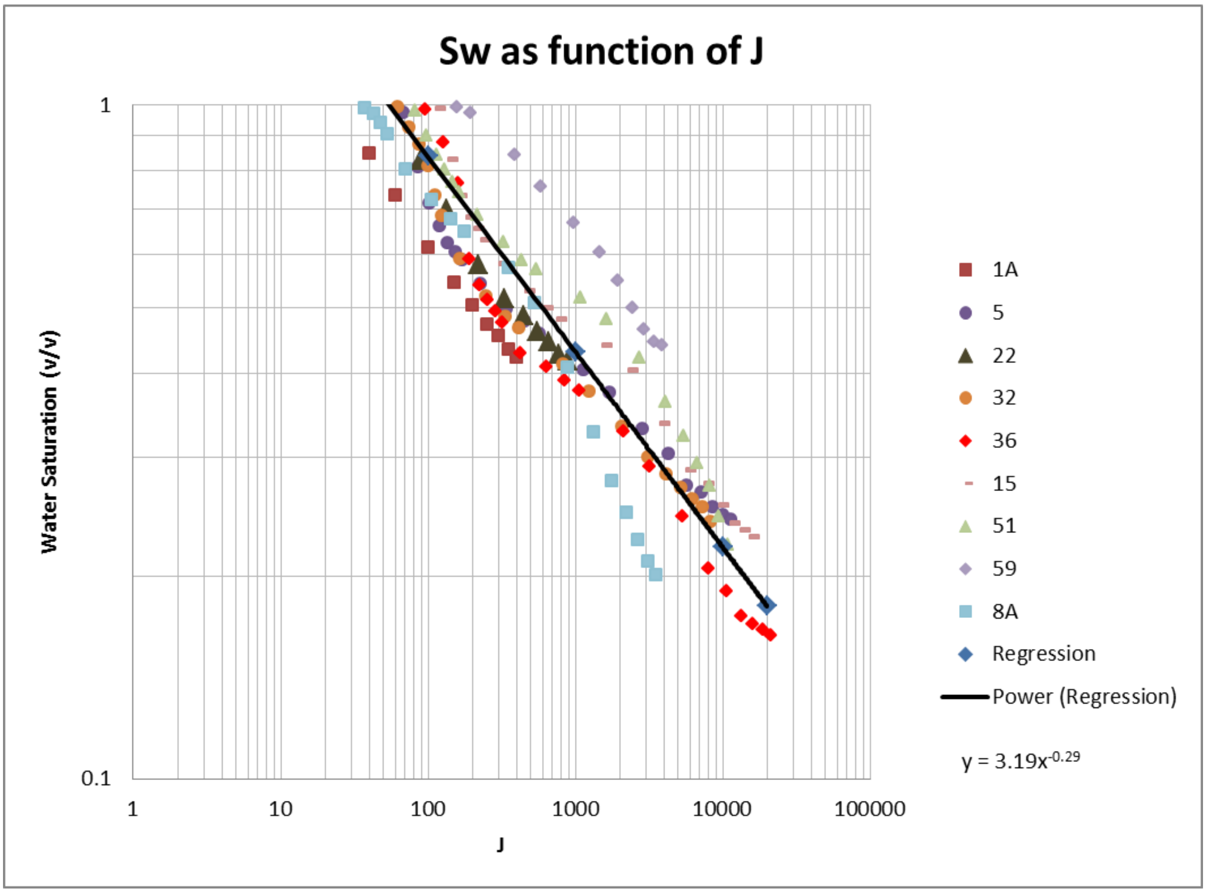


Figure 28 Sw as a function of J showing regression of SHF

2.3.17 Sums and Averages

Sums and averages for the petrophysical interpretation detailed in this summary are shown in Table 11 below. The depth reference is TVD as 29/8a-3 is near vertical and 29/8a-6 is highly deviated. Electro facies are defined where logs are present so gross and net values are over log presence.

TVD Oil leg by facies, using net cutoff from facies (ie 1 and 2 only) with 10.6 porosity cutoff																	
	Well	Zones	Flag Name	Top	Bottom	Reference unit	Gross	Net	Not Net	Unknown	Net to Gross	Net to (Gross-Unknown)	Facies	Av Porosity	Av Permeability	Av Hydrocarbon Saturation Log	Av Hydrocarbon saturation SHF
	29_8A-3	Judy Skaggerak Oil	ROCK			ft	82	0	82	0	0.00	0.00	0				
	29_8A-3	Judy Skaggerak Oil	ROCK			ft	210	195	15	0	0.93	0.93	1	0.16	6.4	0.30	0.46
	29_8A-3	Judy Skaggerak Oil	ROCK			ft	74	74	0	0	1.00	1.00	2	0.23	105	0.49	0.62
	29_8A-6	Judy Skaggerak Oil	ROCK			ft	160	0	160	0	0.00	0.00	0				
	29_8A-6	Judy Skaggerak Oil	ROCK			ft	169	125	45	0	0.74	0.74	1	0.15	4.1	0.42	0.44
	29_8A-6	Judy Skaggerak Oil	ROCK			ft	27	27	0	0	1.00	1.00	2	0.21	48	0.61	0.68

TVD Whole well by facies, using net cutoff from facies (ie 1 and 2 only) with 10.6 porosity cutoff																	
	Well	Zones	Flag Name	Top	Bottom	Reference unit	Gross	Net	Not Net	Unknown	Net to Gross	Net to (Gross-Unknown)	Average Facies	Av Porosity	Av Permeability	Av Hydrocarbon Saturation Log	Av Hydrocarbon saturation SHF
	29_8A-3	Judy Skaggerak	ROCK			ft	178	0	178	0	0.00	0.00	0				
	29_8A-3	Judy Skaggerak	ROCK			ft	435	411	24	0	0.95	0.95	1	0.15	5.4	0.17	0.21
	29_8A-3	Judy Skaggerak	ROCK			ft	100	100	0	0	1.00	1.00	2	0.22	91	0.39	0.46
	29_8A-6	Judy Skaggerak	ROCK			ft	190	0	190	0	0.00	0.00	0				
	29_8A-6	Judy Skaggerak	ROCK			ft	221	172	49	0	0.78	0.78	1	0.15	3.8	0.29	0.32
	29_8A-6	Judy Skaggerak	ROCK			ft	27	27	0	0	1.00	1.00	2	0.21	48	0.57	0.68

TVD Whole well, using net cutoff from facies (ie 1 and 2 only) with 10.6 porosity cutoff																	
	Well	Zones	Flag Name	Top	Bottom	Reference unit	Gross	Net	Not Net	Unknown	Net to Gross	Net to (Gross-Unknown)	Facies	Av Porosity	Av Permeability	Av Hydrocarbon Saturation Log	Av Hydrocarbon saturation SHF
	29_8A-3	Judy Skaggerak	ROCK			ft	714	511	202	0.47	0.72	0.72	1.195	0.17	22	0.21	0.26
	29_8A-6	Judy Skaggerak	ROCK			ft	696	199	239	258	0.29	0.46	1.136	0.16	9.8	0.33	0.37

Table 11: Sums and Averages for Acorn North

2.3.18 Uncertainty Modelling

The sums and averages for the two wells were used in deriving uncertainty values for the petrophysical interpretation.

Using Facies 1 and 2 as NET and a porosity cut off 0.106	NtG **Average**	NtG **Uncertainty 1 std in a normal distribution**	Porosity **Average**	Porosity **Uncertainty 1 std in a normal distribution**	Hydrocarbon saturation **(above the FWL only) Average**	Hydrocarbon saturation **Uncertainty 1 std in a normal distribution**	Percentage occurrence of the facies
Average of both wells all facies	57%	13%	0.16	0.010	0.53	0.09	-
Average of both wells facies 0	0	-	-	-	-	-	35%
Average of both wells facies 1	86%	8%	0.15	0.010	0.49	0.10	49%
Average of both wells facies 2	100%	0%	0.21	0.010	0.63	0.08	16%

Table 12: Average and uncertainty values for static modelling

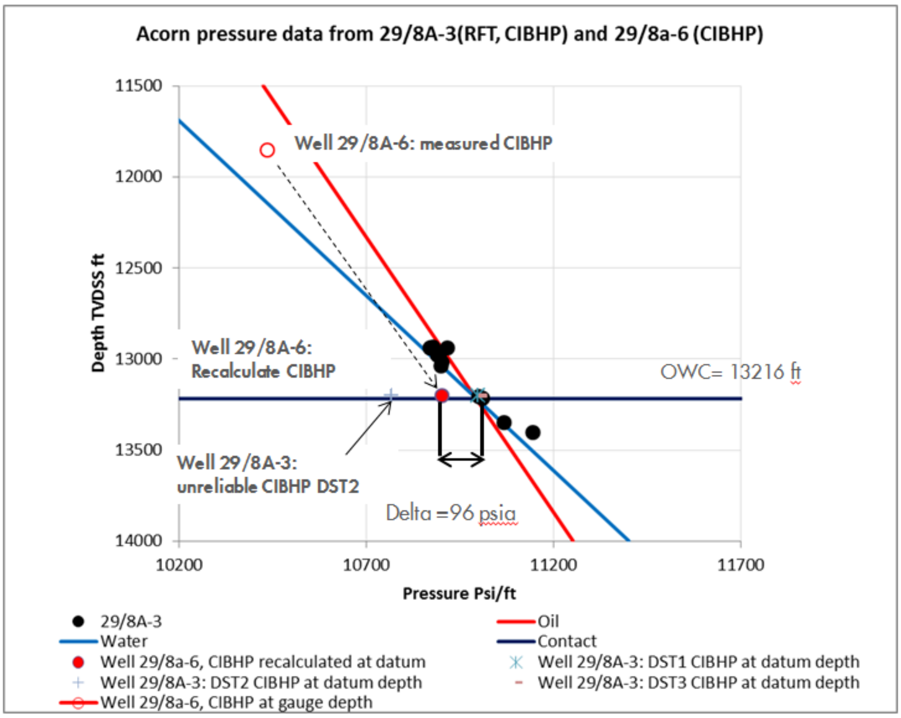
2.3.19 Static Model Close the Loop

A static model close the loop exercise has taken place, the first round of the loop revealed some differences in the way the permeability cut-off had been applied in the static model. Following some investigation a second loop has shown that the petrophysical logs have been appropriately loaded and upscaled in the static model.

2.3.20 Reservoir Pressure/Temperature

Initial formation pressure was tested in 29/8a-6 and 29/8a-3 Acorn North wells. The pressure measurement of well 29/8a-3 is based on RFT data, while well 29/8a-6 does not have any RFT measurements and the pressure was calculated from CIBHP pressure. In order to calculate the CIBHP pressure to a datum depth (13200 ft, TVDSS) the 0.35 psi/ft gradient was used from gauge to top perforation and 0.33 psi/ft from top perforation to the datum depth. The fluid gradient of 0.35 psi/ft, which is oil base mud, was estimated from the well test report by difference between static BHP and THP is 0.35 psi/ft prior to perforation; the formation fluid gradient of 0.33 psi/ft was calculated from PVT data.

Comparison of formation pressures in the wells indicate that formation pressure in well 29/8a-6 is 96 psia lower than in Well 29/8a-3: 10901 psia vs. 10997 psia respectively. QA/QC of well test production data and PVT data could not find any inconsistency in calculation of formation pressure from CIBHP. It is unclear why the pressure is different: there is no geological features (faulting, different facies etc) identified in order to support the pressure inconsistency. Taking into account uncertainty in calculation of initial pressure of well 29/8a-6 and also the fact that the difference between the measured pressures is not significant (96 psi) a decision was made to take initial pressure of 10997 psia (13200 ft TVDSS) measured in Well 29/8A-3 (RFT and CIBHP) as a reference pressure of Acorn North field for further analysis.



- Well 29/8a-3: RFT initial pressure 10997 psia at 13200 ft TVDSS
- Well 29/8a-3: CIBHP (DST1 and DST3) initial pressure measurements are in line with RFT data set, CIBHP (DST2) initial formation is not representative and represents a depleted pressure from DST1 interval, due to bad cementation/cross flowing
- Well 29/8A-6: CIBHP is 10901 psia at 13200 ft TVDSS, which is 96 psia lower than measured pressure (RFT, CIBHP) in well 29/8a-3

Figure 29 Initial formation pressure: wells 29/8a-3 (RFT, CIBHP) vs 29/8a-6 (CIBHP)

2.3.21 Miniplots

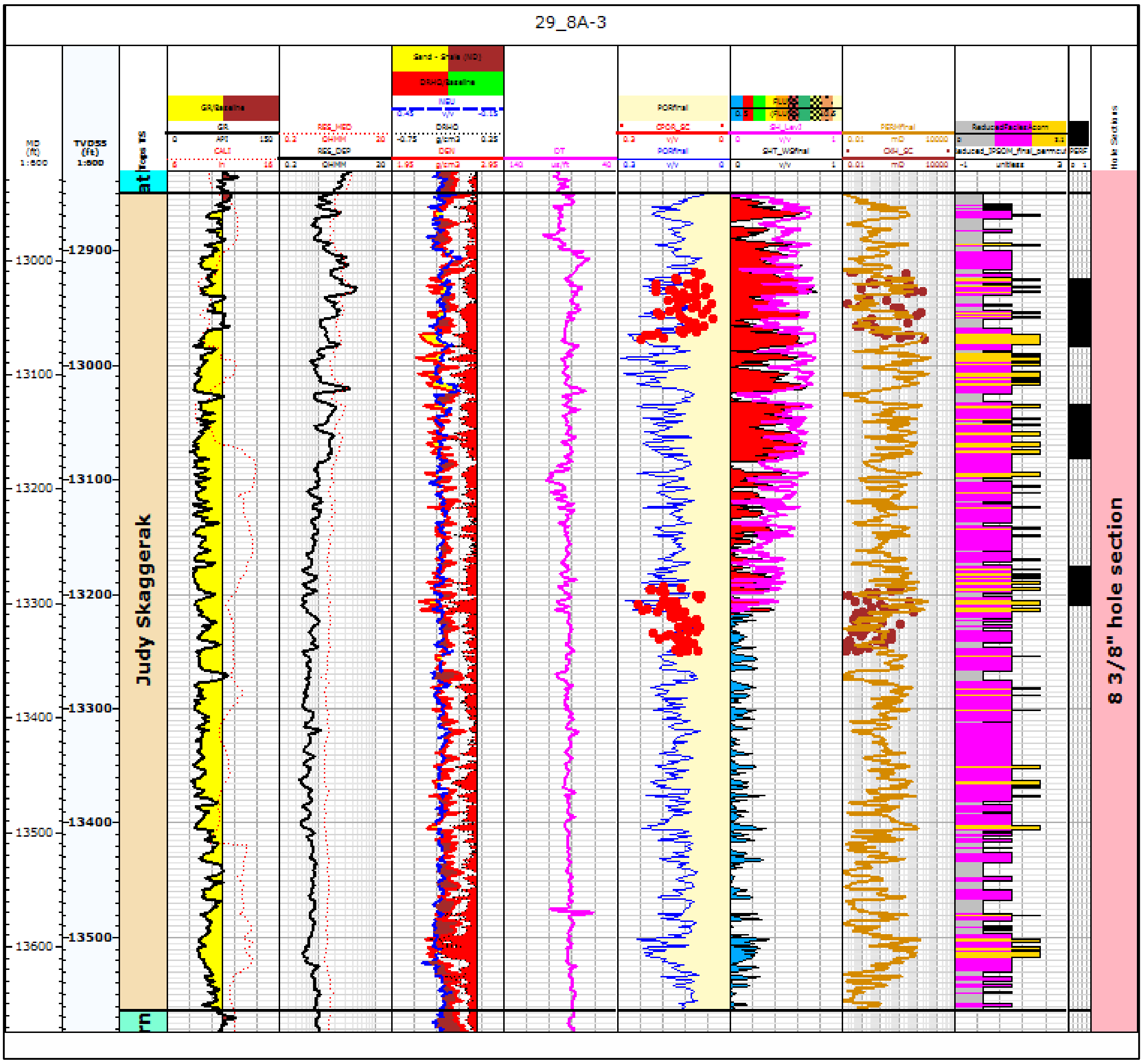


Figure 30: 29/8a-3 Miniplot

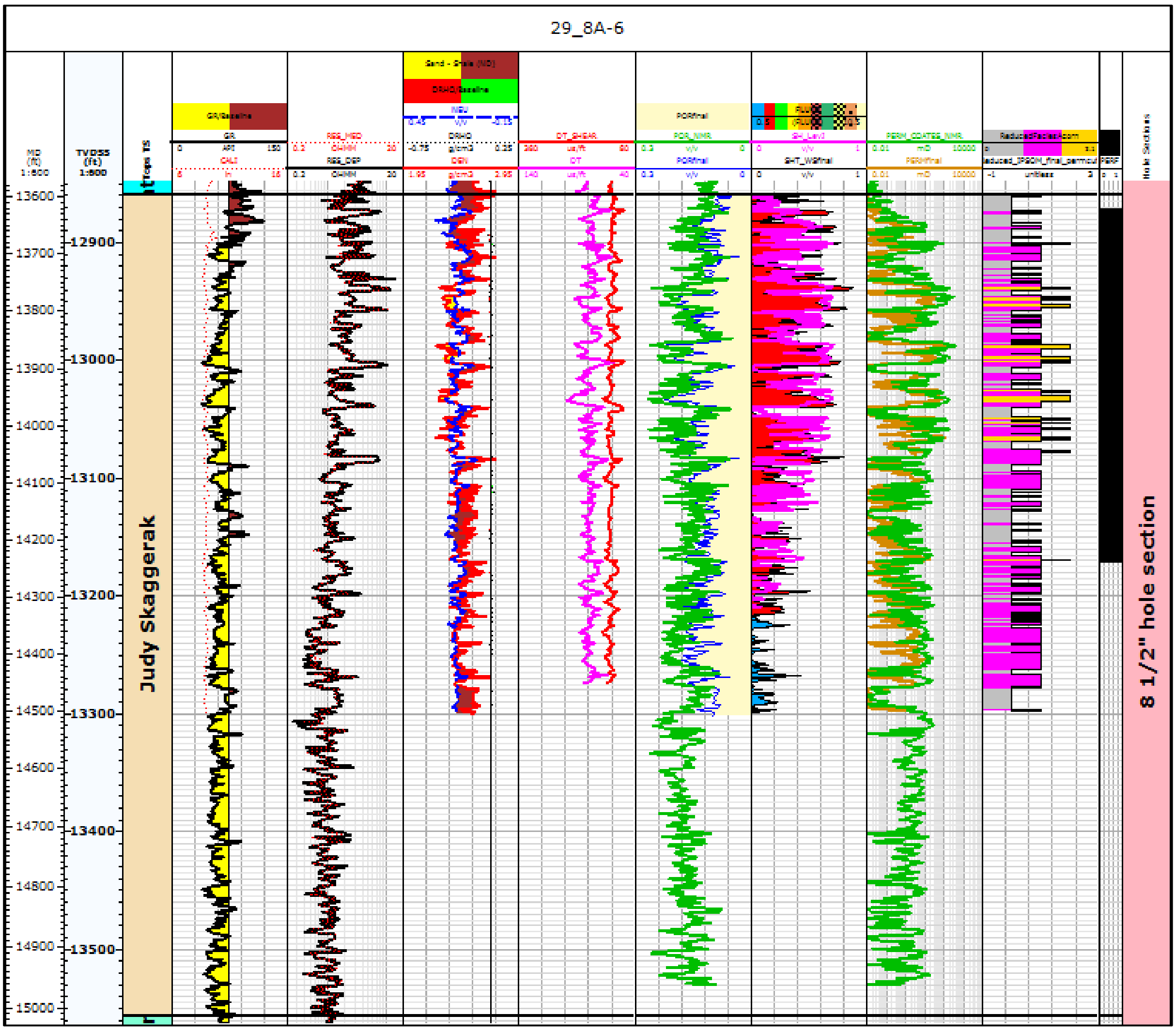


Figure 31: 29/8a-6 Miniplot

3 Beechnut Field

3.1 Geology

3.1.1 Structural Summary

Based on this work, we can propose the following Tectonostratigraphic Summary for the Beechnut Area

- The Beechnut field is an interpod structure containing structural and stratigraphic traps
- Withdrawal of Zechstein Salt created accommodation space between pods of Skagerrak and Smithbank.
- Erosion of the structurally high Skagerrak pods deposits early Fulmar sand unconformably onto the under lying, tilted Rattray volcanics.
- Two separate structural periods have been defined for the Beechnut field Fulmar Play:
    - Pre-Rift: Initially a small amount of accommodation space is created by salt withdrawal, allowing a conformable ribbon of Fulmar to be deposited across the field.
    - Syn-Rift: In the second phase rifting initiates normal faulting creating a much deeper basin.
- The contrasting pre vs. syn rift structural settings create a significant variation in reservoir quality. In addition; uneven withdrawal of the salt has created structurally high areas which have also affected the quality of the reservoir (discussed further later).
- After deposition of the pre and syn – rift Fulmar the area was subsequently uplifted and eroded.
- Finally the Kimmeridge Clay was deposited over much of the Beechnut, providing both the source and seal for the field.

Beechnut sits in an “interpod” region, underpinned by Zechstein salt. This provides the major local control on structuration. Most of the structures were formed in the Late Jurassic-Early Cretaceous North Sea rift phases, with minor inversion in the Cimmerian.

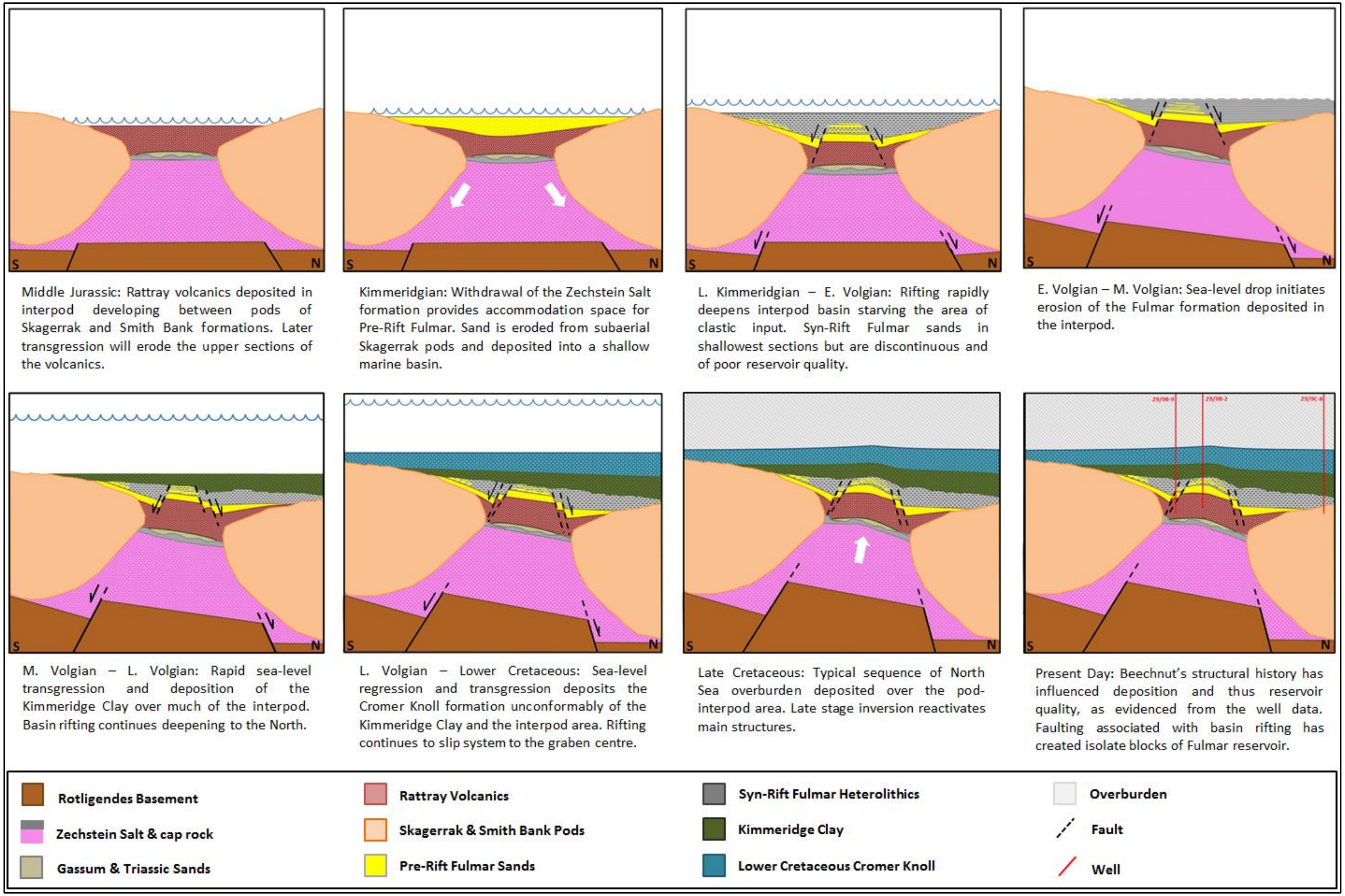


Figure 32 Structural Evolution of the Beechnut Interpod

3.2 Seismic Interpretation

3.2.1 Objectives and Approach

The principle objective was to map the Fulmar reservoir over Beechnut, and describe any reservoir fairways. The Fulmar over Beechnut is challenging to map, as it is thin and has a laterally variable seismic response, linked to facies variation. Mapping therefore had several distinct stages:

1) **Regional Mapping** - Map major surfaces from Basement to Top Chalk, to constrain pod vs. interpod structures.
2) **Fulmar Structure Mapping** – Structural framework and horizon mapping for the key Fulmar Play, critically the Base Upper Jurassic (BUJ) unconformity, and the “Top Pre Rift” surface.
3) **Reservoir Fairway and QI Work** – Using QI with structural to describe Pre Rift sand distribution.

Work was conducted by several interpreters in parallel, with consultation from company experts in dedicated collaborative interpretation sessions. All mapping was undertaken in Petrel, with QI and well ties performed in NDI. Mapping of the Acorn South and Beechnut Deep discoveries was also undertaken at the same time, and is detailed later in this report.

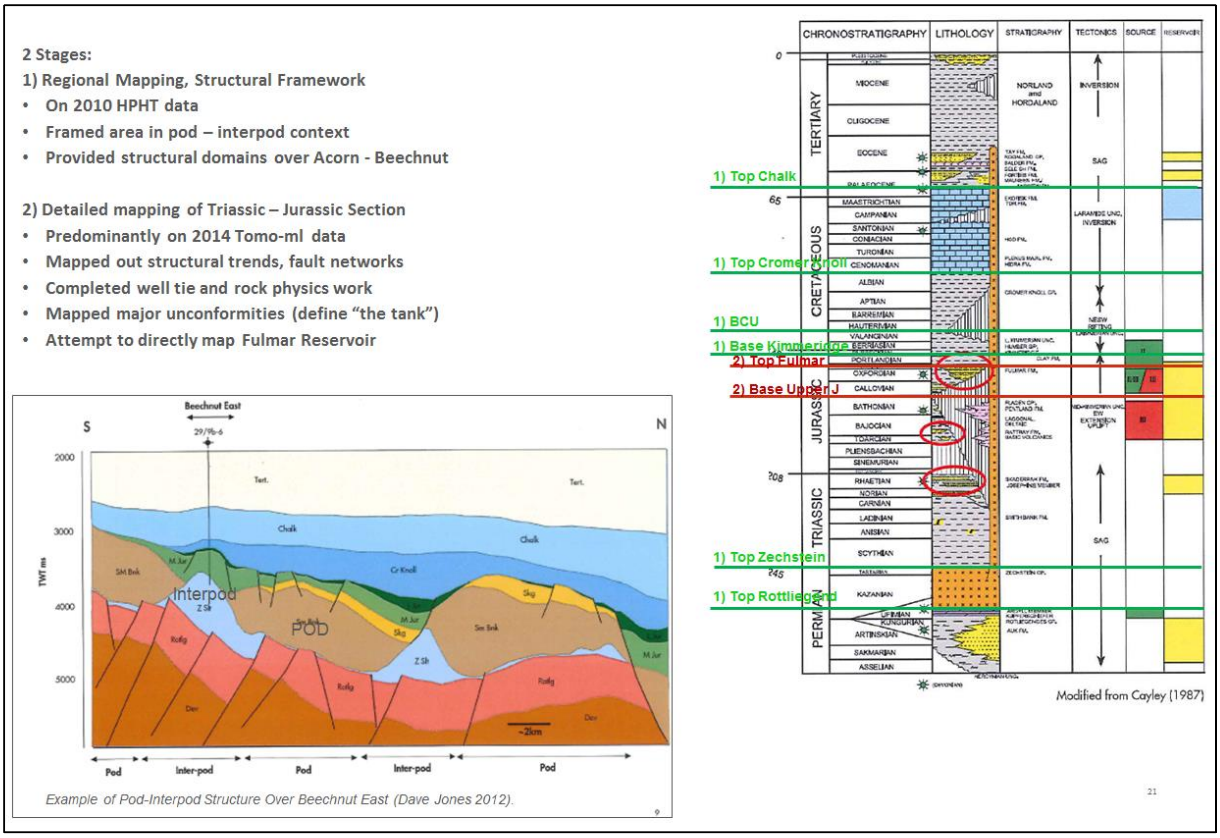


Figure 33 Mapping Strategy Summary with chronostratigraphic chart and Fulmar Horizon

3.2.2 Seismic Database

The TOMO ML reprocessing of the cornerstone dataset was available for the interpretation of Acorn South and Beechnut. This dataset was preferred over the 2010 HPHT volumes as it has a frequency spectrum which preserves more of the low frequency energy than the previous volume. In addition to this, it is the most recent dataset available over Beechnut as we do not have a licence to the Broadseis data over the area of interest.

The TOMO ML data still suffers from the effect of multiples below the BCU. The interval of interest (Fulmar) is located very close to the BCU at the crest of the structure. In some areas, especially the flanks of the field the loop of interest would appear to coincide with a BCU seabed multiple. Inspection of the data showed that in some areas of the flank, dipping features appear to cross-cut the stronger events which are running parallel to the BCU. The same technique that was used on Acorn, of applying a harsh de-multiple filter, was applied to the TOMO ML. This post-processing technique provided significant improvement in the seismic data. Removing some of the multiple energy built confidence in interpreting the cross-cutting reflectors as the subsurface, instead of those running parallel to the BCU which where supressed after filtering. This version of the TOMO ML full stack volume was used to guide the interpretations in areas of complexity, with the Full stack data being used as reference cube.

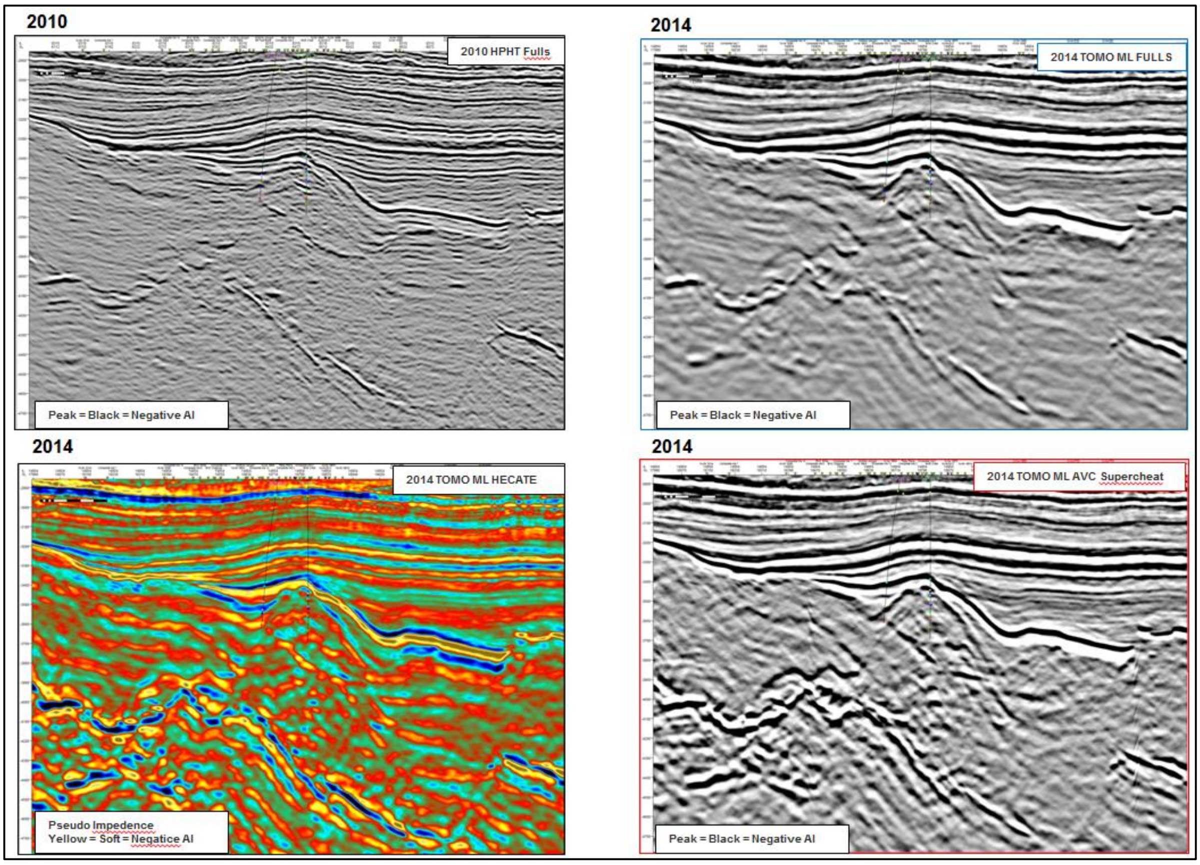


Figure 34 Optimised 2014 TOMO ML seismic volumes vs. 2010 HPHT data, Beechnut East

3.2.3 Well Ties and Picking Philosophy (RL/AL)

There are five wells on Beechnut, 4 relatively vertical wells (29/9B-2, -3, -6 & -9) and one deviated well (29/9B-9Z) and one vertical well on Acorn South (29/8B-2S). The vertical wells provided the best well ties over the interval of interest (T Kimmeridge Clay to T Rattray) and below. There were two exceptions to this which did not have enough density coverage to enable a decent seismic to well tie, 29/9B3 and 29/9B-6.

The seismic interpretation of Beechnut and Acorn South was carried out on the CGG TOMO ML reprocessing of the HPHT dataset and Figure shows the respective well ties for the Acorn South well, 29/8B-2S and two Beechnut wells, 29/9B-9 and 29/9B-2. In all wells there is a strong correction and reasonable match between the synthetic and the seismic.

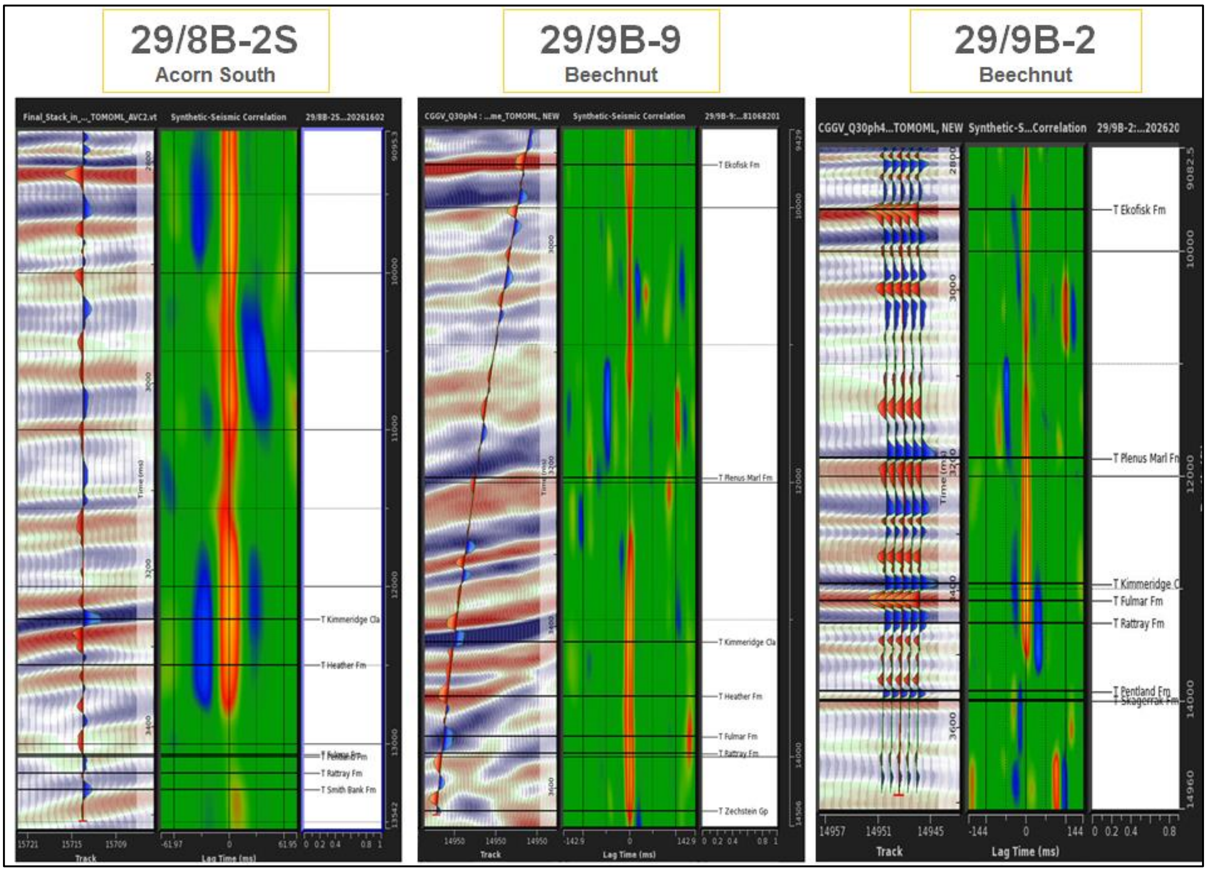


Figure 35 Final Seismic to Well Ties against the CGG TOMOML cornerstone HPHT seismic for Acorn South and Beechnut wells, all generated using Butterworth synthetic wavelets

The main horizons show consistency across the whole area and Table 13 summarises what seismic loop or zero-crossing each key horizon was interpreted on. These horizons were mapped iteratively with the structural fault interpretation.

Table 13 Picking philosophy for Acorn South and Beechnut

Surface	Pick	Comment
BCU	Reflectivity – PEAK (Soft Loop)	
Base Kimmeridge Clay/ Top Syn-Rift	Hecate – S CROSSING	Pseudo – impedance pick
Top Pre Rift	Reflectivity – S CROSSING	Top of "Fulmar Loop"
BUJ	Reflectivity – Z CROSSING	Base of "Fulmar Loop"
Top Zechstein	Reflectivity – S CROSSING	Interpreted some phase rotation
Top Carboniferous	Reflectivity – S CROSSING	Interpreted some phase rotation

Once the major structural horizons were mapped, an attempt was made to map the basal sand unit in the Fulmar / Heather section – the Pre Rift. This sits within a single soft kick above the BUJ, and can therefore be characterised as a single cycle response. In zero phase reflectivity, the base and top of this loop were mapped to approximate the Pre-Rift package. The top loop was tied to the well control to create a Top Pre Rift surface.

In summary the picking philosophy for Beechnut was as follows:

- Map gross structure – particularly deeper salt features and major bounding faults
- Map Base Cretaceous Unconformity (BCU/T Kimmeridge Clay) - regional soft kick
- Map Base Kimmeridge / Top Syn-rift, iterating with fault interpretation - regional hard kick
- Map Base Upper Jurassic, iterating with fault interpretation – regional zero-crossing
- Map Top Pre-rift – zero crossing associated with "Fulmar Peak"

This overall picking philosophy was checked against well ties corresponding to the conventional HPHT data and no changes were required.

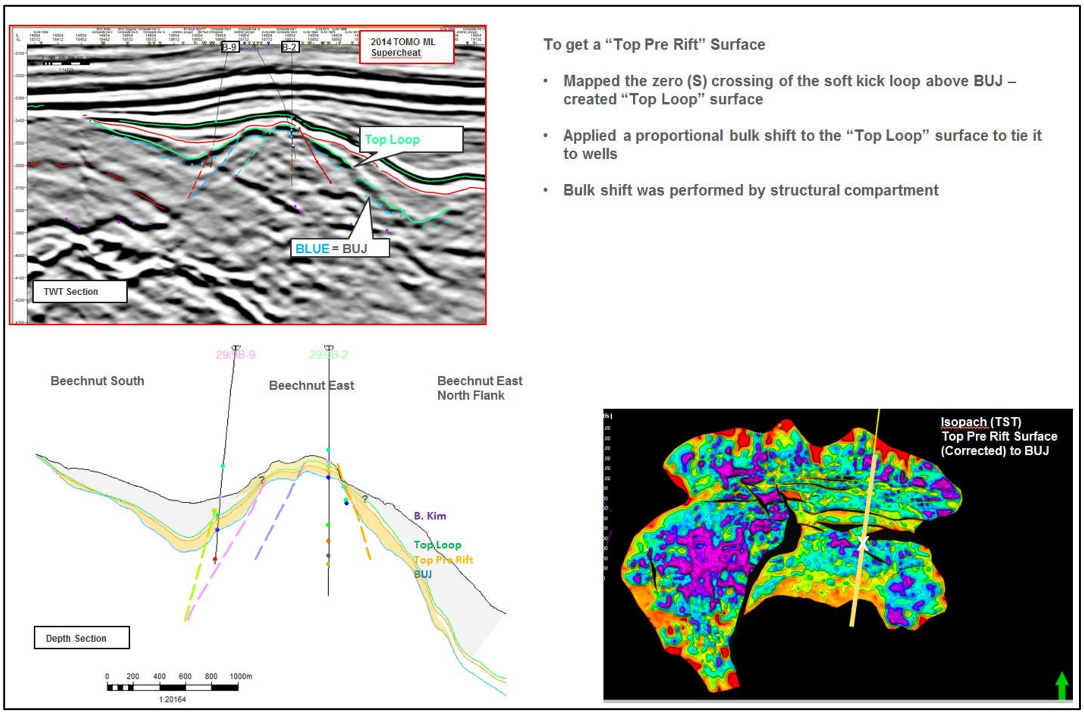


Figure 36 "Top Pre Rift" Seismic Interpretation

3.2.4 Structural Interpretation

Regional

A regional set of surfaces and associated structural framework were developed, which demonstrate the rift history of the basin and pod-interpod plays around Beechnut. The critical structural features for Beechnut are as follows:

- Beechnut is underpinned by a large E-W trending salt wall, which underpins an interpod with its apex around the 29/9B-2 well. This is separate from the Acorn South salt diapir.
- A Triassic pod is interpreted between Beechnut and Acorn S.
- 4 way structural closure is interpreted at BUJ, Base Kimmeridge and BCU level over Beechnut East
- No such closure is observed at any structural level on Beechnut West.

Fulmar Play

The above concepts can be illustrated with type lines, with special attention paid to the Base Upper Jurassic unconformity, upon which the Pre Rift section sits. Further key observations at this level are as follows:

- The upper Jurassic section is eroded on top of the Triassic pods surrounding Beechnut, and also to the east.
- A major detachment fault separates Beechnut East Fulmar/Heather from Beechnut West.
- The structural orientation of Beechnut East and West are very different at BUJ level, driven by the shape of the salt body beneath.
- The strength of the “Pre Rift” seismic response is much weaker in West vs. East.

Beechnut East is compartmentalised by multiple E-W trending faults, while Beechnut West has no obvious structural closure.

Interpretation confidence is lower in the West than East, due to the weaker seismic reflection character of the Base Upper Jurassic / Pre Rift sections. This is proposed this to be lithology linked, explored in the next section.

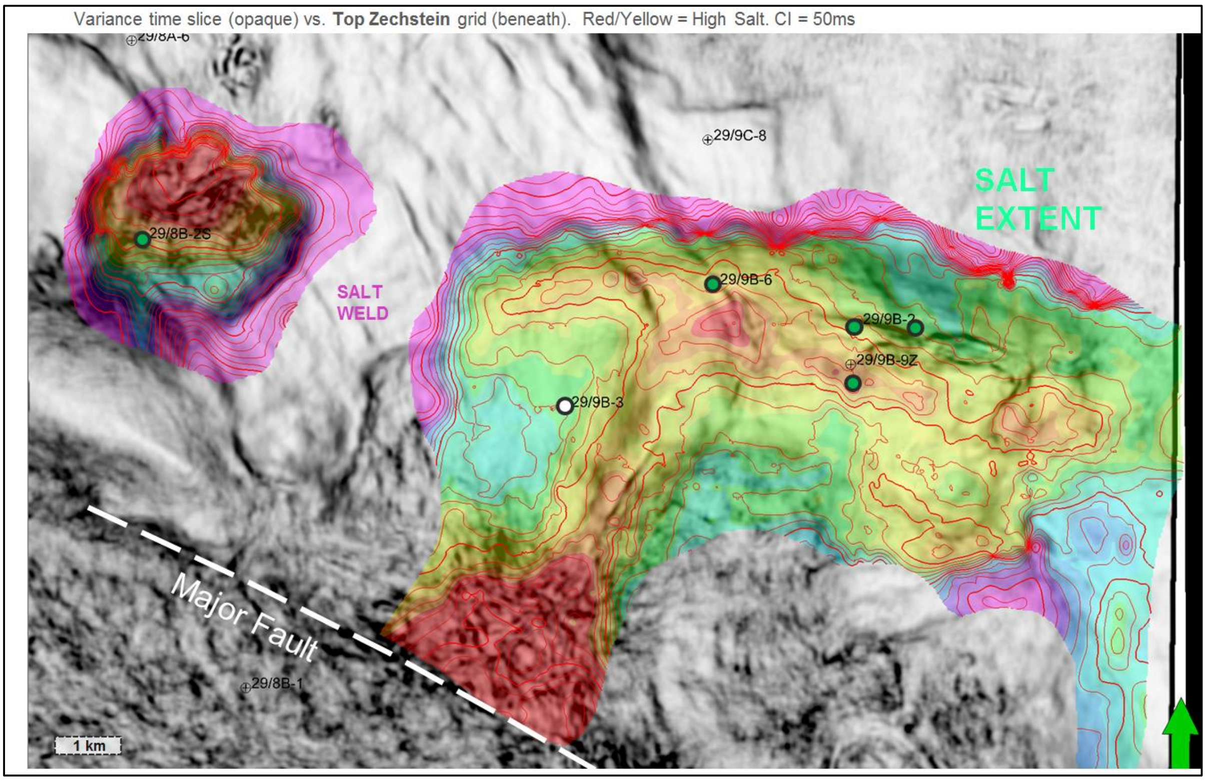


Figure 37 Top Zechstein salt (TWT) vs Variance Time Slice.

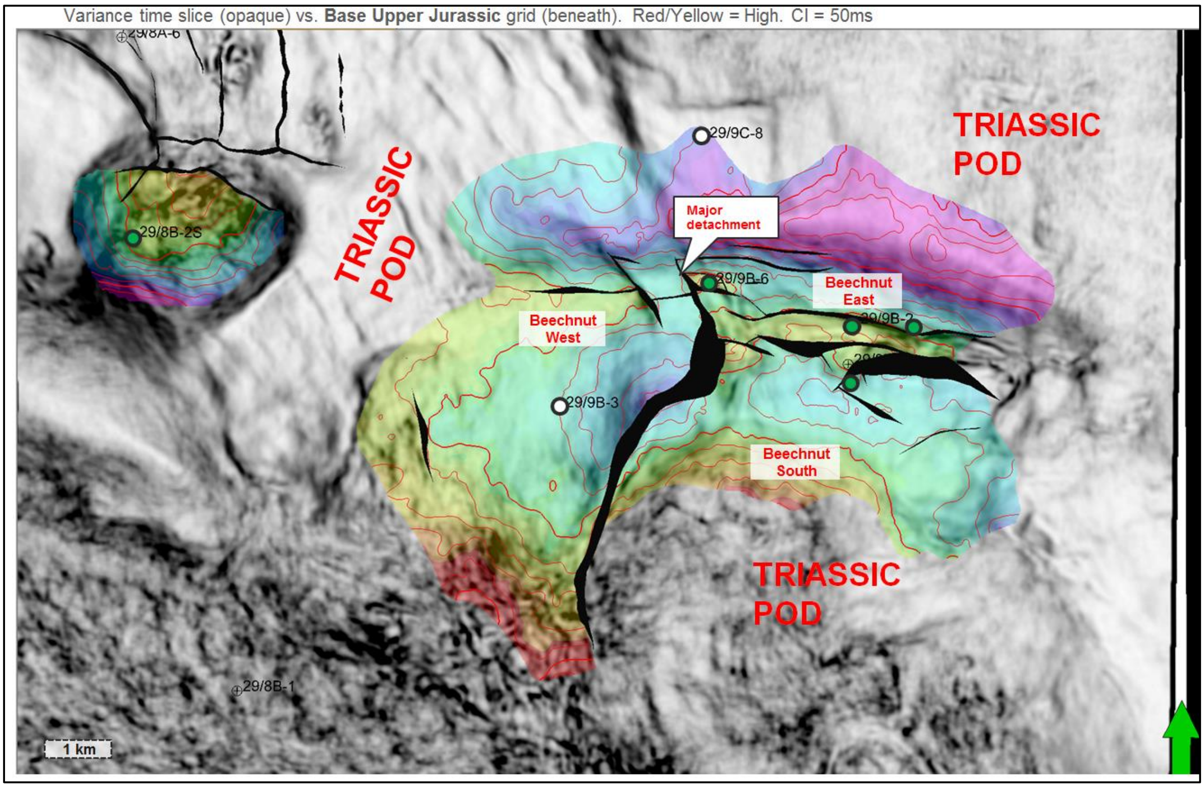


Figure 38 Base Upper Jurassic Time Structure (TWT) Vs. Variance. Edge of BUJ = interpreted max extent of Fulmar (eroded elsewhere). Note lack of closure on Beechnut West.

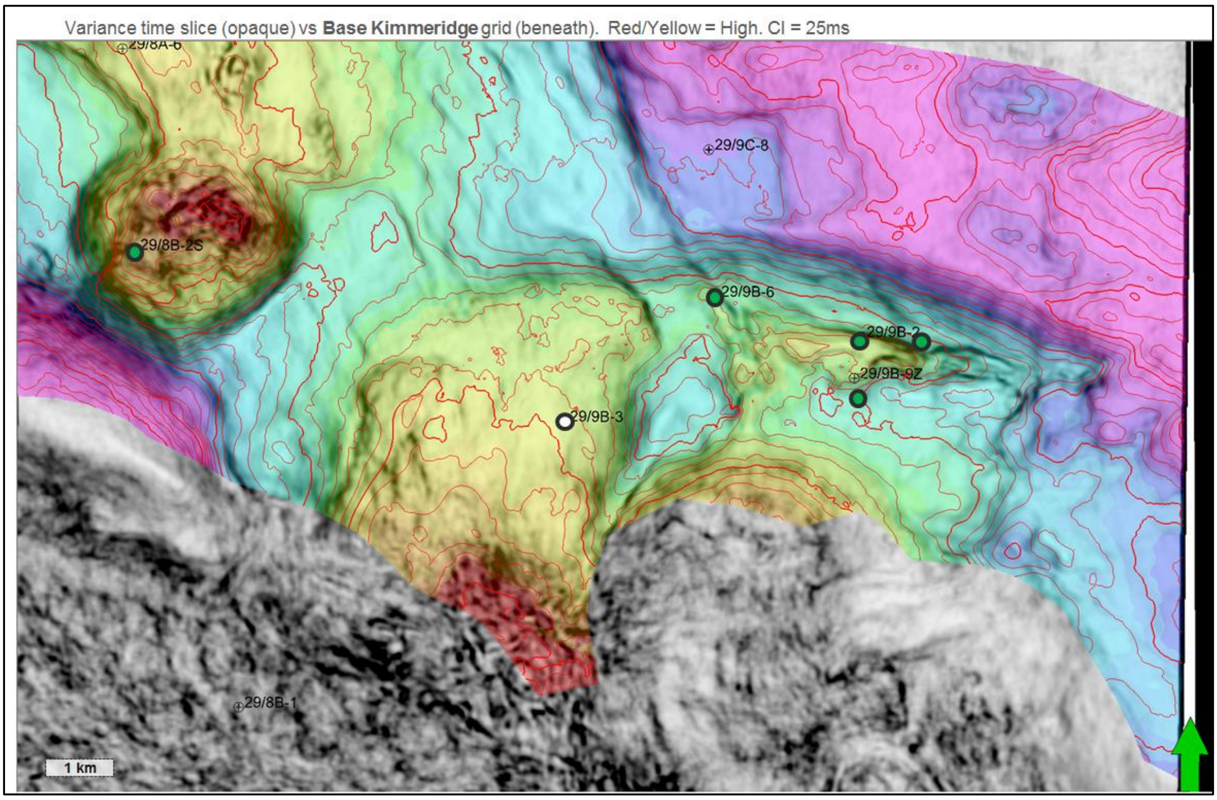


Figure 39 Base Kimmeridge Time Structure (TWT) vs. Variance

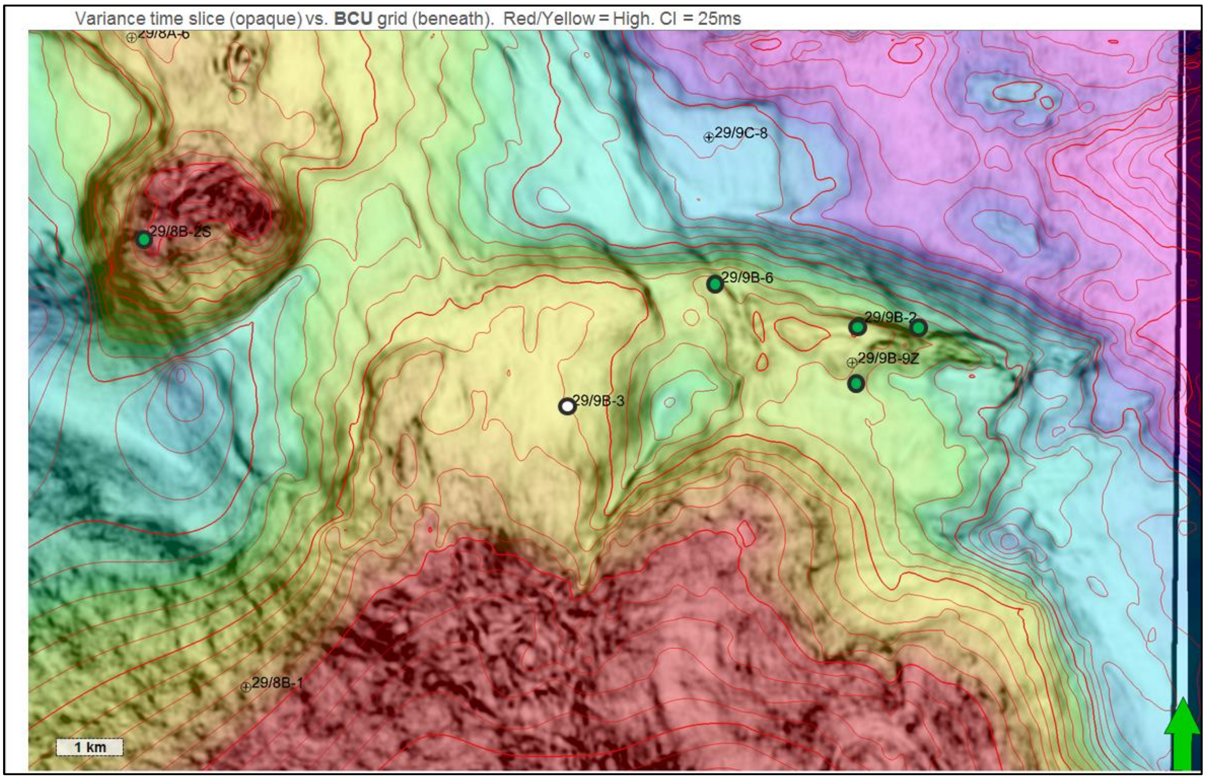


Figure 40 BCU Time Structure (TWT) vs. Variance. Note robust 4 way closure over Beechnut East, and lack of closure over Beechnut West.

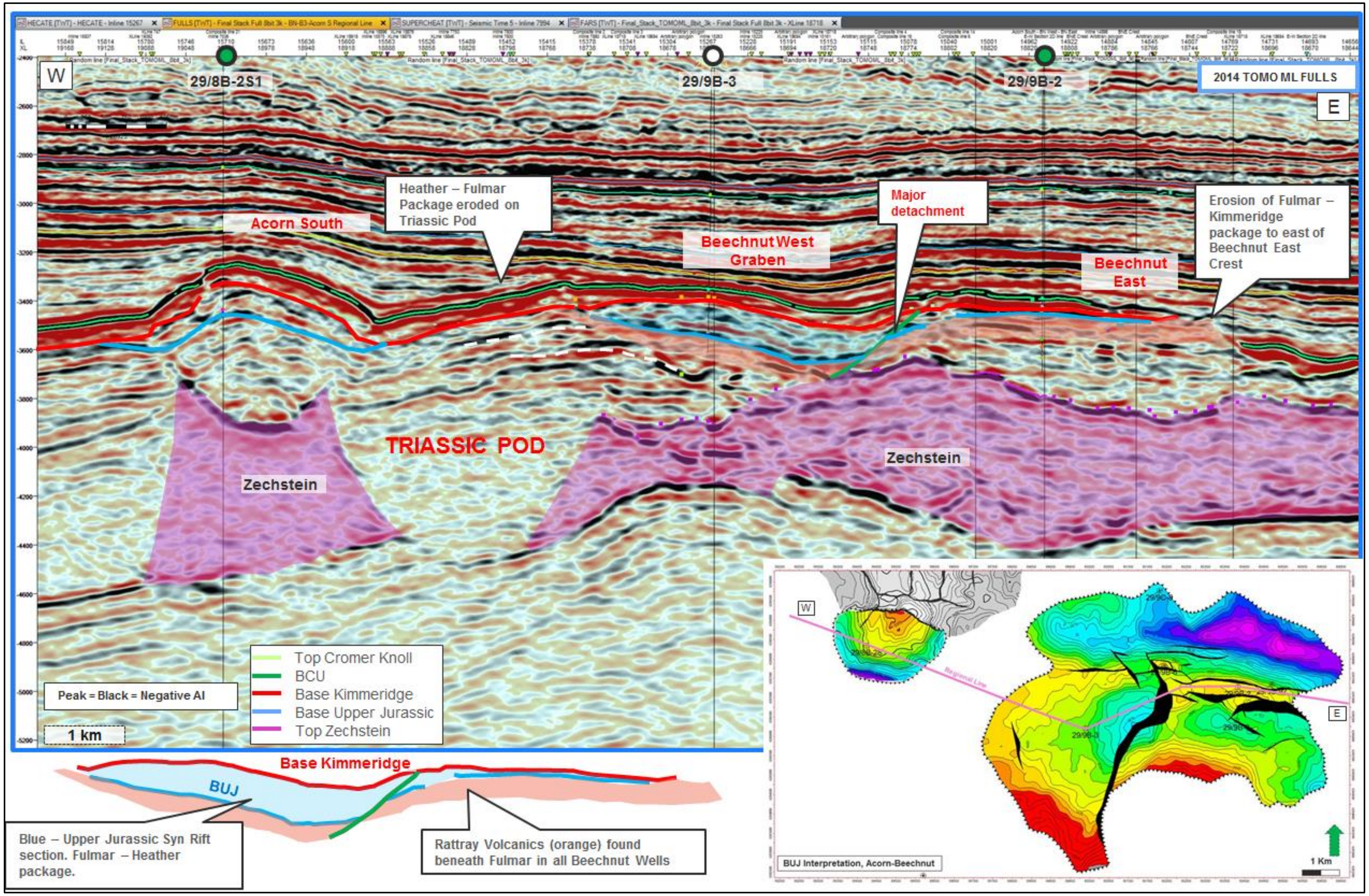
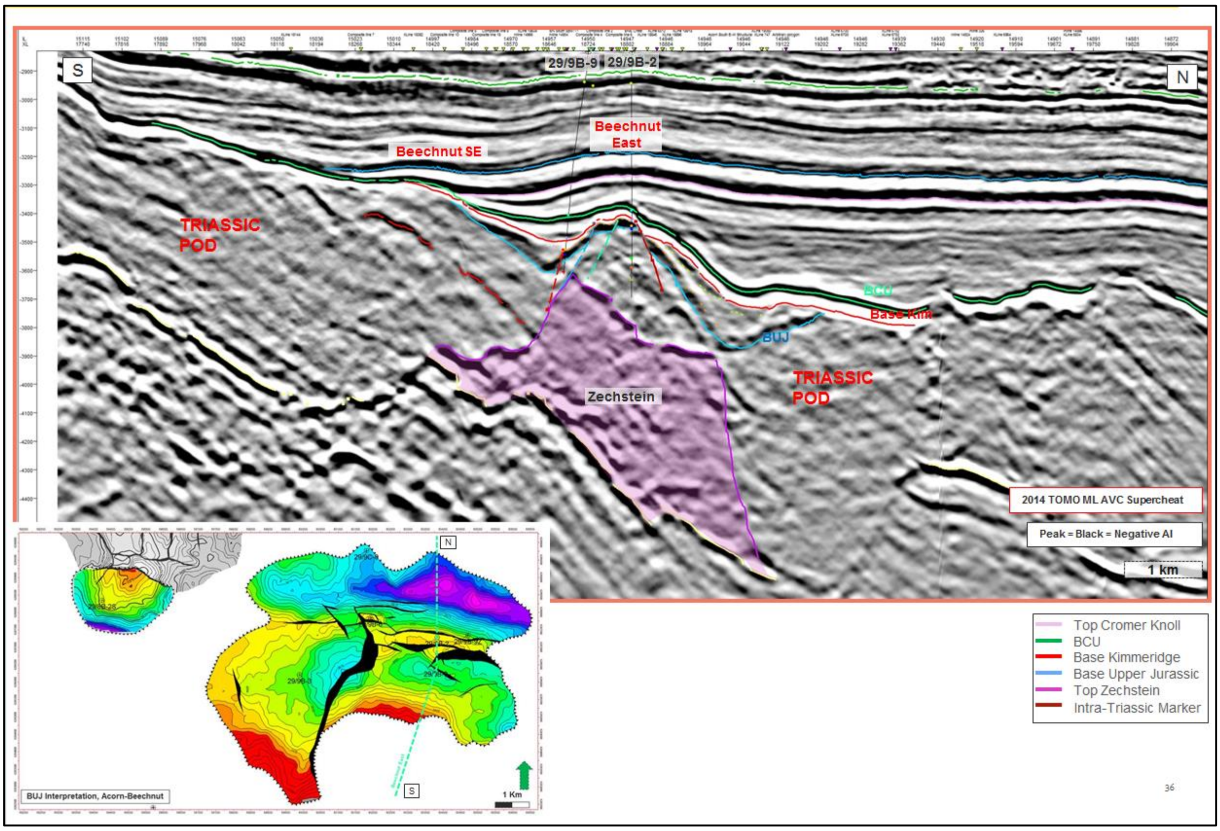


Figure 41 Seismic line from Acorn South to Beechnut East demonstrating pod-interpod concept



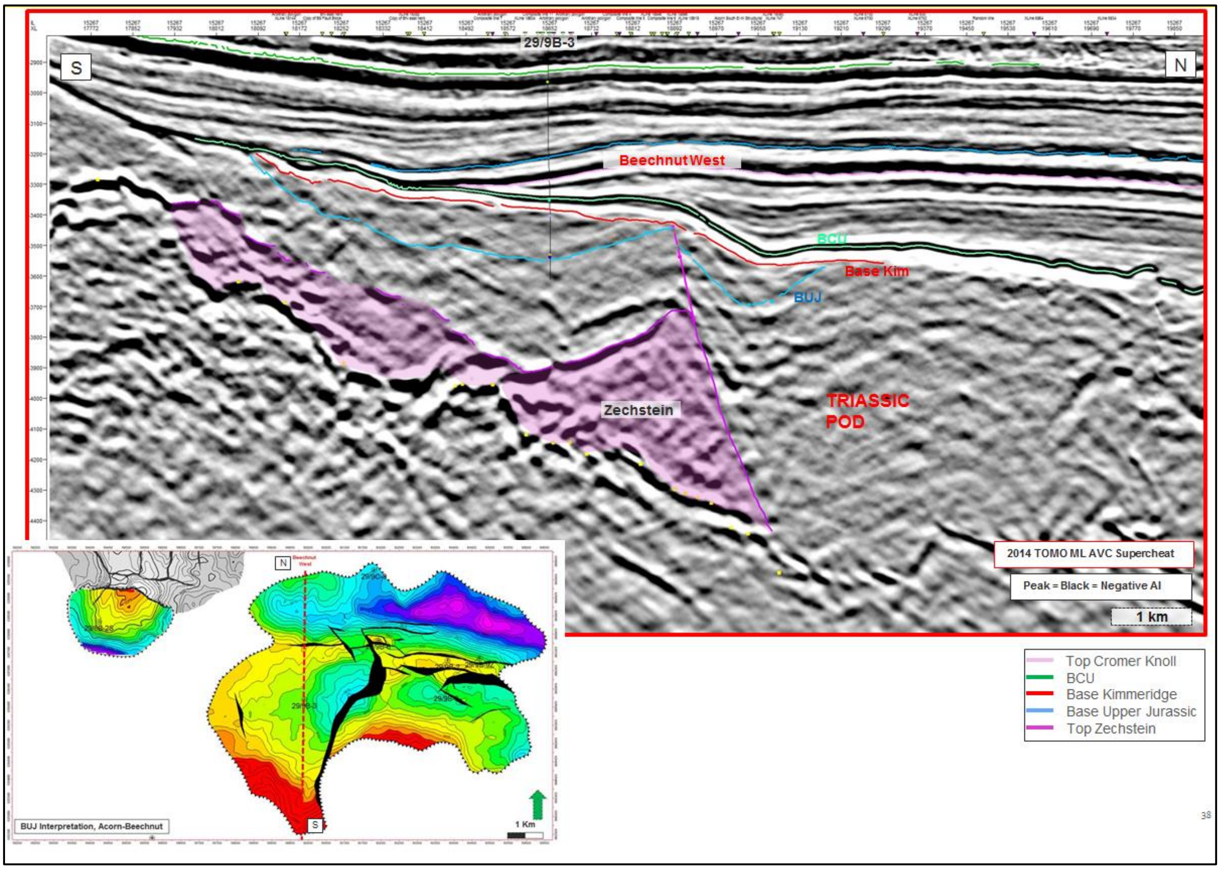


Figure 42 Structural comparison of Beechnut East (top) and Beechnut West

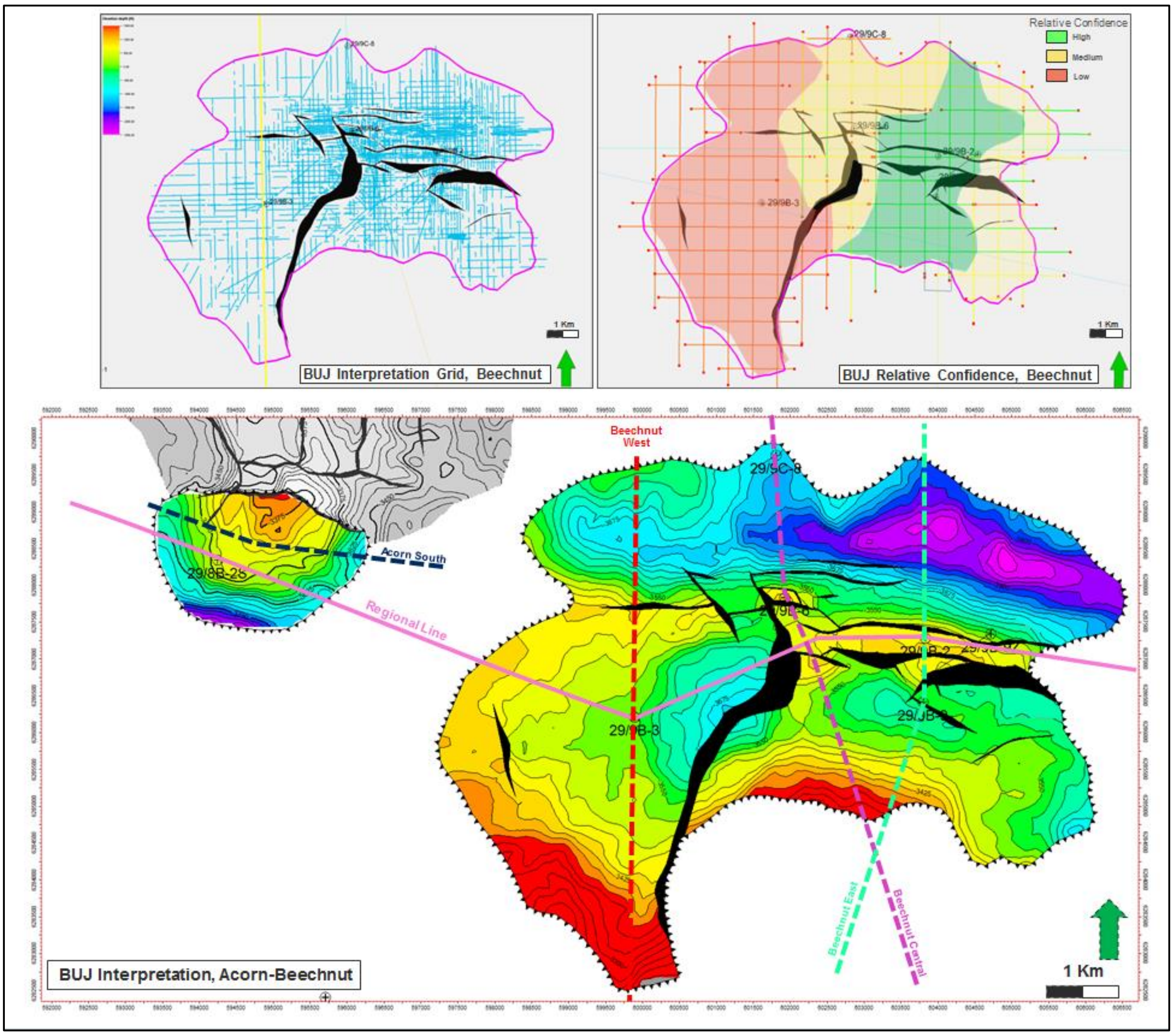


Figure 43 Final TWT map of BUJ (Base Fulmar or Heather Fm.) with Beechnut interpretation grid and confidence map

3.2.5 Reservoir & Quantitative Interpretation

The Pre Rift reservoir section sits within a single seismic loop, and is hence susceptible to interference and tuning effects. The tuning thickness derived from wedge modelling indicated that Pre-rift with a thickness less than approximately 150-160 ft would be affected by tuning interference. The thicknesses of Pre-Rift recorded in the Beechnut wells ranges from 30 – 150 ft approximately. This indicates that over a majority of the area of interest the loop associated with the Pre-Rift is subject to tuning interference. As a result, a significant residual uncertainty remains on reservoir thickness around the area.

Wedge modelling was used to determine whether or not the seismic character could help define the reservoir quality and distribution. Three vertical wells from Beechnut were used to represent the varying Pre-Rift quality; 29/9B-2 as the best, 29/9B-9 as the poorest and 29/9B-6 in the middle. The modelling found that there is a clear response in amplitude, at the Top Pre-Rift, to the quality of the reservoirFigure . The Sum of Positive Amplitudes (SPA) taken over this interval can therefore be used as a guide to reservoir quality and distribution. The areas of bright amplitudes indicate presence of a relatively good Pre-rift, whereas, dim areas indicate relatively poor Pre-rift or none at all. The SPA attribute also indicates that the reservoir is not evenly distributed across the area and has significant variation in quality over short distances, demonstrated by the patchy nature of the amplitudes.

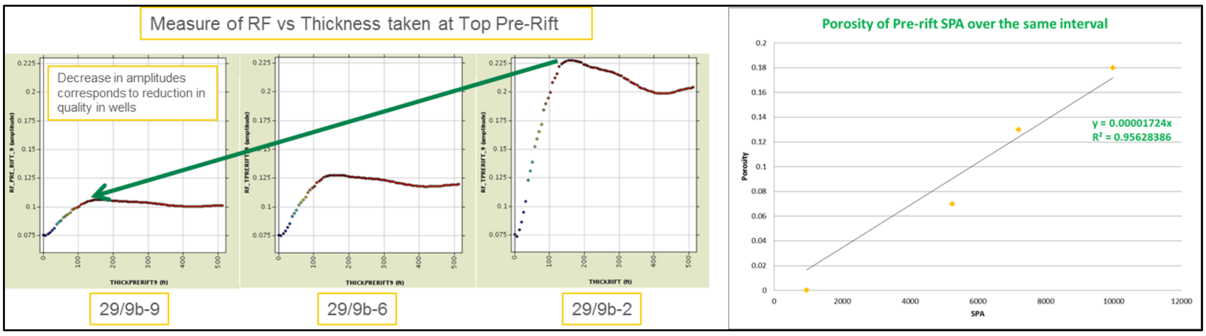


Figure 44 Wedge modelling results showing the relationship between amplitude and reservoir quality for the Pre-Rift

A stronger soft kick associated with the pre rift section should therefore, equate to better reservoir quality. There is a good correlation between the seismic response at the wells and their respective quality, for example around the 29/9B-2 well where reservoir quality is high; the pre rift section is associated with a strong soft kick. In the area around the 29/9B-3 well, where the pre-rift section has entirely shaled out, there is a very weak amplitude response.

On this basis, the Beechnut area can be split broadly into a high amplitude eastern area, where a sand fairway is proposed, and a low amplitude western area, where no reservoir is expectedFigure . Well data shows us that the pre-rift reservoir has significant lateral poroperm variation over short distances, with areas of non-deposition or erosion. The “patchy” appearance of the amplitude response is consistent with this model. A potential modern day depositional analogue can be found in the Outer Hebrides.

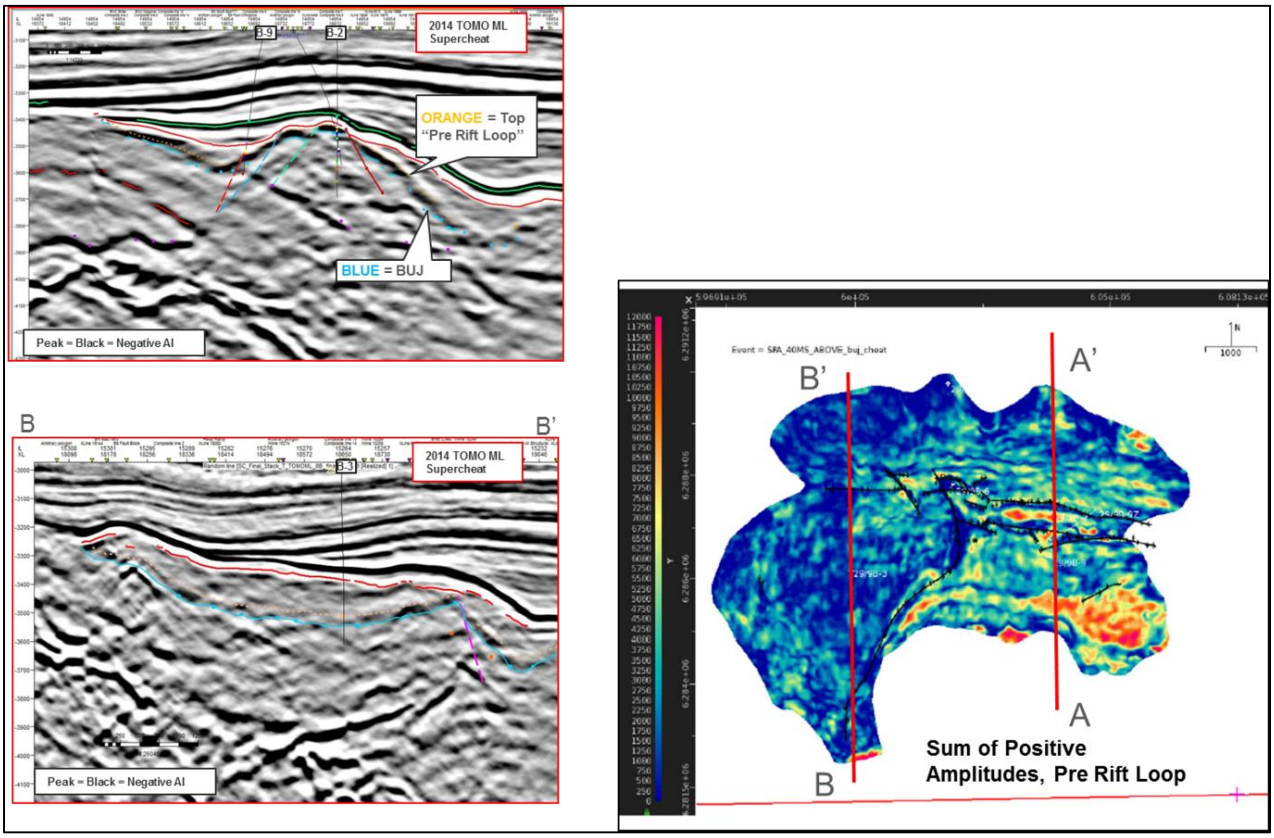
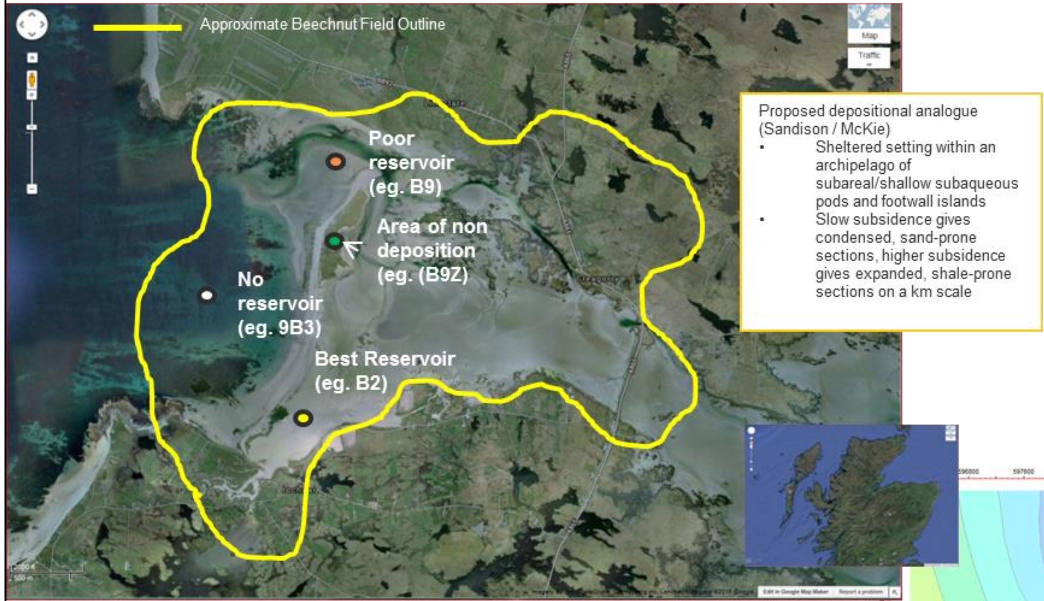
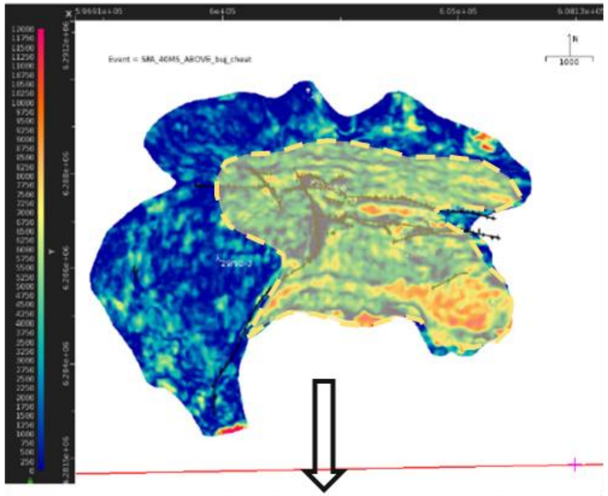


Figure 45 Amplitude of Pre-Rift seismic loop across Beechnut Area. Note lower amplitudes in West than East and patchy appearance.





- Seismic Attributes and facies variation point to a thin, heterogeneous reservoir system
- Reservoir quality controlled by sediment supply vs. subsidence rate
- Modern day analogue – Hebridean archipelago
- Good, poor and no reservoir within 1 km transect

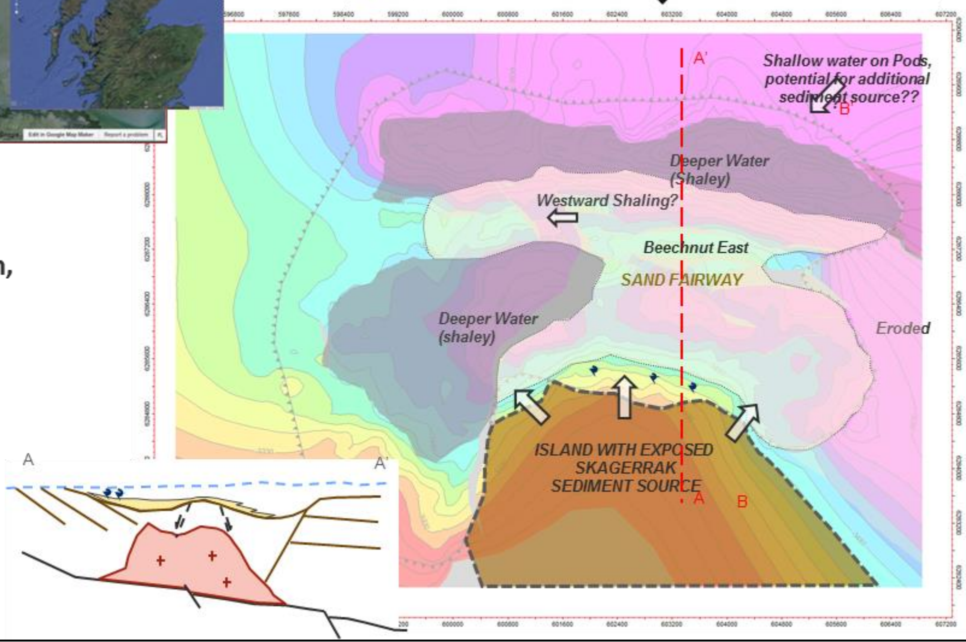


Figure 46 Proposed Pre-Rift reservoir fairway and analogue depositional environment

3.2.6 Depth Conversion

A velocity model over Beechnut and Acorn South was required to depth convert the key horizons, Base Kimmeridge Clay and Base Upper Jurassic, that define the main (Fulmar) reservoir interval. Depth surfaces of these key horizons were required for use in both field and prospect well and volumetric assessment, testing the following:

- Volumes
- Spill Points
- Compartmentalisation

Analysis of sonic logs over the area indicated that a five layer velocity model would appropriately capture the velocity trends observed in the logs. In order to capture the velocity inversion within the chalk this layer over Beechnut was split into two. The same methods that were tested over Acorn North were looked at over Beechnut. The preferred velocity function for each individual layer was defined prior to starting the evaluation of the next layer:

- Surface to Top Chalk
- Top Chalk to Top Cromer Knoll
- Top Cromer Knoll to BCU
- BCU to Base Upper Jurassic (BUJ)
- BUJ and below

The final velocity model is a combination of both scaled PSDM and Linear V0k trends. The CGG PSDM velocity model scaled by 1.002 was deemed suitable down to Top Chalk; below this the model velocities are too slow through the chalk. The CGG PSDM does not capture the regional trends through the chalk and as a result the Linear V0k trends were derived for these intervals. The final velocity model is summarised in Figure 47.

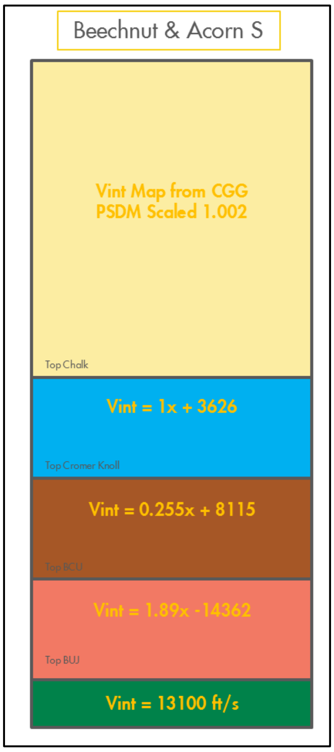


Figure 47 Summary of Final Velocity Model for Acorn South and Beechnut

The uncertainties associated with the key horizons are summarised in Table 14. The effective thickness uncertainty in the reservoir was defined as 65 ft (225-160).

Table 14 Summary of the Depth Uncertainities for Beechnut and Acorn South

Formation	UNITS	Pick Uncertainty	Velocity Uncertainty	Total Depth Uncertainty
T Chalk	ft (2SD)	± 75	± 60	± 100
T Cromer Knoll	ft (2SD)	± 150	± 70	± 165
BCU	ft (2SD)	± 75	± 65	± 100
T Syn-Rift	ft (2SD)	± 150	± 65	± 160
T Pre-Rift	ft (2SD)	± 200	± 100	± 225
BUJ	ft (2SD)	± 200	± 100	± 225

3.3 Petrophysics

3.3.1 Objectives and Approach

The objective of this work was to reassess the petrophysical evaluation of the Beechnut wells that had previously been completed during the 27th licence round application. During this re-evaluation of the five wells that lie within the Beechnut acreage and the Acorn South well, 29/8B-2s a mineralogical model was established and an auditable trail of the work created. The outputs of the petrophysical modelling were then used as inputs into the FastTrack model created by UIX.

3.3.2 Reservoir Units

The work primarily concerned the Jurassic Fulmar sands, although a deeper target in the 29/9B-2 well contains both Lias and Skagerrak formations. A quick look evaluation of an additional well, 29/8A-4, in the licence block that lies apart from the two main structures has been completed with this well penetrating both Pentland and Skagerrak formations. The interpretation of this well has been completed differently due to the timing of the evaluation and the level of detail required for this prospect.

The Fulmar has been split into two different packages, Pre-Rift and Syn-Rift. The different structural settings create a significant variation in reservoir quality, with the Pre-Rift Fulmar thought to be more productive than the Syn-Rift. Both packages are not found in all of the wells.

The 29/9B-3 contains sediments that are of the same age as the Fulmar packages seen elsewhere across the field however it is thought that the Fulmar sands were not encountered in this well.

The 29/8B-2s well contains two different ages of Fulmar sand, one that matches the Beechnut wells and one termed a Curlew Fulmar, for the purpose of this evaluation they have been treated as one.

The formation tops for the main evaluation in Beechnut and Acorn South can be found in Table 15 and Table 16

	Tops (ft MD)			
Wells	BCU	Base Kimm.	Top Pre-Rift	BUJ
29/9B-2	13039	13190 Top Syn-Rift	13305	13388
29/9B-3	13013	13241	13822 *Fulmar Equivalent	14034
29/9B-6	13130	13336 Top Syn-Rift	13387	13418
29/9B-9	13342	13746	14047	14203
29/9B-9z	14674	14858 Top Syn-Rift	n/a	14913

Table 15 Beechnut Tops

	Tops (ft MD)				
Well	BCU	Base Kimm.	Top Fulmar	Top Curlew Fulmar	BUJ
29/8B-2s	12286	12446	13146	13159	13262

Table 16 Acorn South Tops

3.3.3 Data Available

Table 47 Wireline Data Availability

									Porosity Logs				Resistivity								
Field	**Well Name**	**Operator**	**Year**	**Mud Type**	**Contractor**	**Core**	**RFT**	**GR**	**Calliper**	**Density**	**Sonic**	**Neutron**	**ILD**	**ILM**	**SFL**	**Phase**	**Attenuation**	**LLD**	**LLS**	**MSFL**	**Image Logs**
Acorn	29/8B-2s1	Unocal	1983	INVERUL (O/B)	Schlumberger			GR	CALI	RHOB	DT	NPHI	ILD	ILM	SFLU						
Beechnut	29/9B-2	Premier	1985	GEL/SPERSENE/RESINEX	Schlumberger	YES	YES	GR	CALI	RHOB	DT	NPHI	ILD	ILM	SFL			LLD	LLS	MSFL	
Beechnut	29/9B-3	Premier	1987	INTERDRILL N.T.	Schlumberger	YES	YES	GR	CALI	RHOB	DT	NPHI	ILD	ILM	SFL						
Beechnut	29/9B-6	Premier	1989	INTERDRILL N.T.	Baker Atlas	YES	YES	GR	CAL	ZDEN	AC	CN	RILD	RILM							Dipmeter
Beechnut	29/9B-9	Amerada Hess	2001	LTOBM	Schlumberger	YES		HCGR	LCAL	LDS		APLC					AT90				
Beechnut	29/9B-9Z	Amerada Hess	2002	LTOBM	Schlumberger	YES	YES	GR_ARC		RHOB	DTBC	TNPH				P40H	A40H				
Acorn	29/8A-4	Shell	1987	OBM	Dresser-Atlas			GR	CAL	DEN	AC	CN	ILD	ILM							

Core Data Availability

Core data was acquired in all of the wells in the Beechnut field. However analyses were only performed on four of the wells in the Beechnut field. The only SCAL measurements in the field could be found on the 29/9B-2 well, and these only consisted of pore volume compressibility analyses on 4 plugs.

Well	Core acquired	Cored Intervals	Core Number
29/8B-2s	No		
29/9B-2	Yes	13340-13399 13403-13443 14098-14187 14319-14431	1 2 3 4
29/9B-3	Yes	13100-13160.5 13161-13221 13221-13272.25 13370-13460.7	1 2 3 4
29/9B-6	Yes	13390-13417	2
29/9B-9	Yes	13749-13927 13927-14109	1 2
29/9B-9z	Yes	14907-15058	1

Table 18 Core data availability

Well	CPOR	KH	KV	CDEN
29/8B-2s				
29/9B-2	x	x	x	x
29/9B-3				
29/9B-6	x	x	x	x
29/9B-9	x	x	x	x
29/9B-9z	x	x		x

Table 19 Core analysis data availability

3.3.4 Conventional and Special Core Analysis

Conventional core sample analysis was performed in 5 of the wells. However as 29/9B-3 did not encounter Fulmar sands the data points there have not been used for input in to the Fulmar model. The one special core analysis measurement in 29/9B-2 was used in determining the porosity correction due to stress for the field taking account the different isostatic stresses that had been calculated for each well.

The remainder of the measurements that would have come from performing special core analysis e.g. m, n, capillary pressure curves and stressed permeability had to instead be taken from analogues.

3.3.4.1 In-situ Isostatic Stress and Porosity Correction

Using the compressibility measurement from 29/9B-2 and applying that relationship to each of the wells at their individual effective stresses calculated from the pressure/depth gradients in each well, an individual porosity correction due to stress can be calculated, see Table 20. There was no permeability correction performed as no analogue stress correction allowed the permeability to match the well test results, with the permeability from logs always resulting in too low a permeability.

	Mean effective isostatic stress (psi)	Porosity correction
29/8B-2s	1490	0.945
29/9B-2	1630	0.944
29/9B-3	1490	0.945
29/9B-6	1810	0.943
29/9B-9	2230	0.940
29/9B-9z	1750	0.943

Table 20 Porosity Correction factors for Beechnut wells

3.3.4.2 Porosity Permeability Relationship

The corrected core porosity and uncorrected core permeability samples in the 29/9B-2, 29/9B-6 and 29/9B-9 wells containing the Pre-Rift Fulmar were then used to derive the por-perm relationship for the field, as shown in Figure 48 giving an equation,

$$\log_{10} cperm = 21.32162 * cpor - 3.486769$$

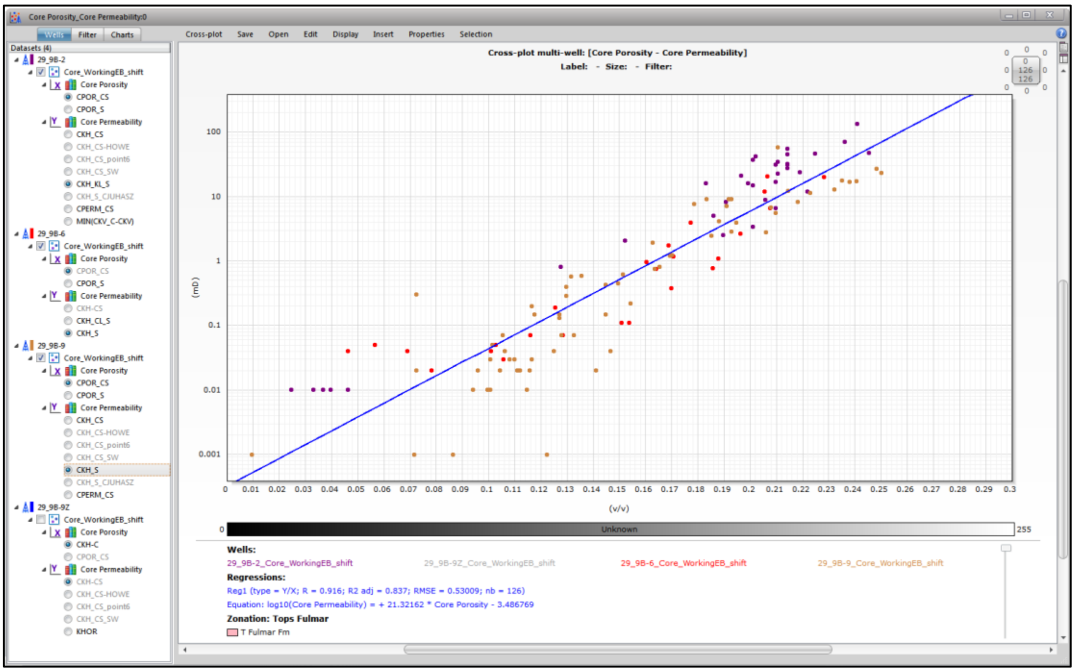


Figure 48 Por-Perm Relationship from Core

3.3.4.3 Special Core Analysis

As no special core analyses were performed in the wells, the input parameters for the saturations had to be taken from analogues.

The Archie parameters were examined for a number of fields that had been identified as analogues including Howe, Curlew B and Cook. The Archie parameters were taken from the recent petrophysical study on Howe, but the full range of parameters across the fields and other Fulmar sands such as from the Shearwater field was captured in the uncertainty estimations.

3.3.5 Wireline Log Interpretation

3.3.5.1 Volume of Shale

A Vshale from GR was created for all of the wells using a 5-95% histogram method for the Fulmar formation, Table 21.

Well	5%	95%
29/9B-2	21.5	55
29/9B-6	25	85
29/9B-9	37	67
29/9B-9z	75	121
29/8B-2s	21.5	86

Table 21 5-95% GR values for Vshale calculation

3.3.5.2 Porosity and Saturation Evaluation

A density porosity was calculated but this was deemed unsuitable due to the matrix density not increasing with decreasing core porosity as would be expected for a normal cementing process in a clastic reservoir, see Figure 49. Therefore, a Quanti Elan mineralogical model was used to determine the porosities and saturations.

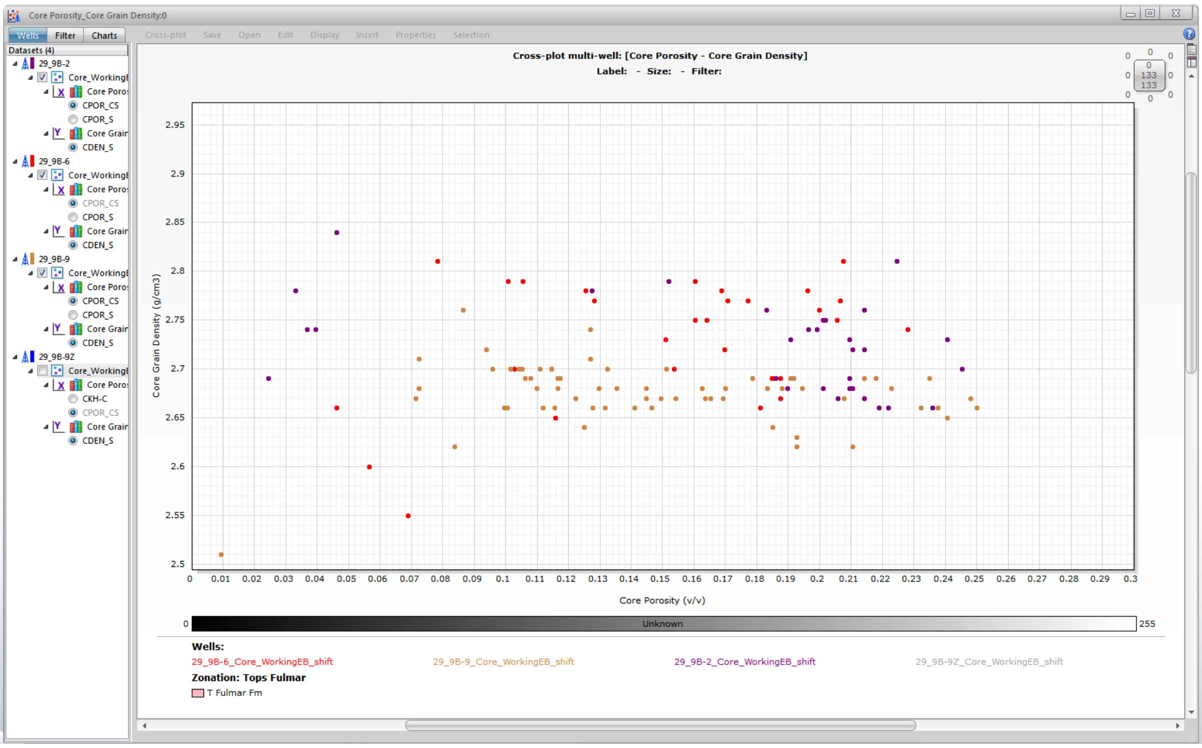


Figure 49 Core porosity v core grain density

The log inputs into the Quanti Elan model were fairly consistent across the wells as can be seen in. The inputs were weighted equally across the different parameters for each of the different wells.

Well (All Fulmar Intervals)	GR	NEU	DEN	DT	RES_DEP	RES_MED	RES_SLW
29/9B-2	X	X	X	X	X		X
29/9B-6	X	X	X	X	X	X	
29/9B-9	X	X	X	X	X	X	
29/9B-9z	X	X	X	X			
29/8B-2s	X	X	X	X	X	X	

Table 22 Inputs into Quanti Elan

The minerals to be used in the modelling process were chosen from the geological reports and cuttings descriptions, whilst avoiding an undetermined system where the number of outputs is greater than the number of inputs.

The m and n values were taken from analogues and the values from the Howe field of m=1.88 and n=1.8 were used with a water salinity of 0.012 which was the assumed base case water salinity in the Acorn field of 200 kpm at Beechnut reservoir temperature.

Using the por-perm relationship derived from core, the permeability could be calculated using the output porosity curve from the Quanti Elan model.

3.3.5.3 Net Reservoir

The net reservoir was calculated using the sum of the weight of the sand and silt created from the Quanti model divided by the total weights of all the minerals combined, to create a lithology based discriminator for reservoir quality set where the volume of silt/shale was greater than 55% of the total volume of the minerals in the model,

$$(shale + silt)/(shale + silt + quartz + dolomite + pyrite)$$

his corresponded with an approximately 10% porosity cut-off to give the potential net zones of the reservoir. This was tested down to a value that would result in pay even in the very low ~7% region where an oil sample was taken in the 29/9B-9z well.

3.3.5.4 Sums and Averages

Table 23 Acorn South and Beechnut Sums and Averages

Well	Zones	Top	Bottom	Reference unit	Gross	Net	Unknown	Net to Gross	Av Porosity	Av Clay Volume	Av Water Saturation	Av Oil Saturation	EHC
29_9B-2	T Syn Rift Fulmar	13190	13305	ft	115	28	0	0.24	0.111	0.30	0.38	0.62	1.88
29_9B-6	T Syn Rift Fulmar	13336	13387	ft	51	0	0	0.00				1.00	0.00
29-9B-9z													
29_9B-2	T Pre Rift Fulmar	13305	13388	ft	83	77	0	0.92	0.183	0.13	0.19	0.81	11.35
29_9B-6	T Pre Rift Fulmar	13387	13418	ft	31	26	0	0.83	0.166	0.24	0.31	0.69	2.94
29_9B-9	T Pre Rift Fulmar	14047	14203	ft	156	69	0.25	0.44	0.134	0.23	0.49	0.51	4.71
29_8B-2S	T Fulmar Fm	13146	13159	ft	13	5	0	0.35	0.14	0.19	0.24	0.76	0.49
29_8B-2S	T Curlew Fulmar Fm	13159	13262	ft	103	25	0	0.24	0.16	0.17	0.25	0.75	3.04

Once the net cut-offs were applied the sums and averages for each of the wells could be computed to get the average porosity, saturation and permeability across the different formations. From this it is possible to see that the 29/9B-2 has the best reservoir properties and there is quite a range throughout the other wells. This is also supported by the well test results which showed the best well test in the 29/9B-2 well.

3.3.6 Fluid Contacts and Reservoir Pressure/Temperature

Each of the wells was found to be at a different pressure. The wells encountering the Fulmar Pre-Rift sand all see an oil down to. The 29/9B-9z well which only encounters the Syn-Rift Fulmar had one successful oil test at a level of 13,643 ft TVD. The rest of the samples were tight.

The regionals CNNS trend was used to define the reservoir temperature which gives a reservoir temperature of 325 deg F at a reference datum of 13,800 ft; however the PVT reports give a range of 306-320 deg F. Therefore for Beechnut a temperature value of 320 degF is used with a normal distribution and a standard deviation of 10 degF.

3.3.7 Saturation Height Function

Height of transition zone (ft above OWC)	Upper Fulmar Sw (%)	Fractional Oil Saturation (%)
300	21	100
200	25	95
100	33	85
50	41	75
10	59	52
0	100	0

Table 24 Water and oil saturations for height above OWC

3.3.8

3.3.8 Reservoir Pressure

Initial formation reservoir pressure was measured in 4 Beechnut E&A wells: well 29/9b-6, 29/9B-2, 29/9-9Z, 29/9-9. Each well located in as separate fault block and has different reservoir pressure, which is an indication of fault blocks compartmentalization.

Well	Initial Pressure, psia	Datum depth, ft TVDSS
Well 29/9B-9Z	11130	13800
Well 29/9B-9	10625	13800
Well 29/9B-2	11040	13800
Well 29/9B-6	11231	13800

Table 25 Beechnut RFT/MDT pressure data

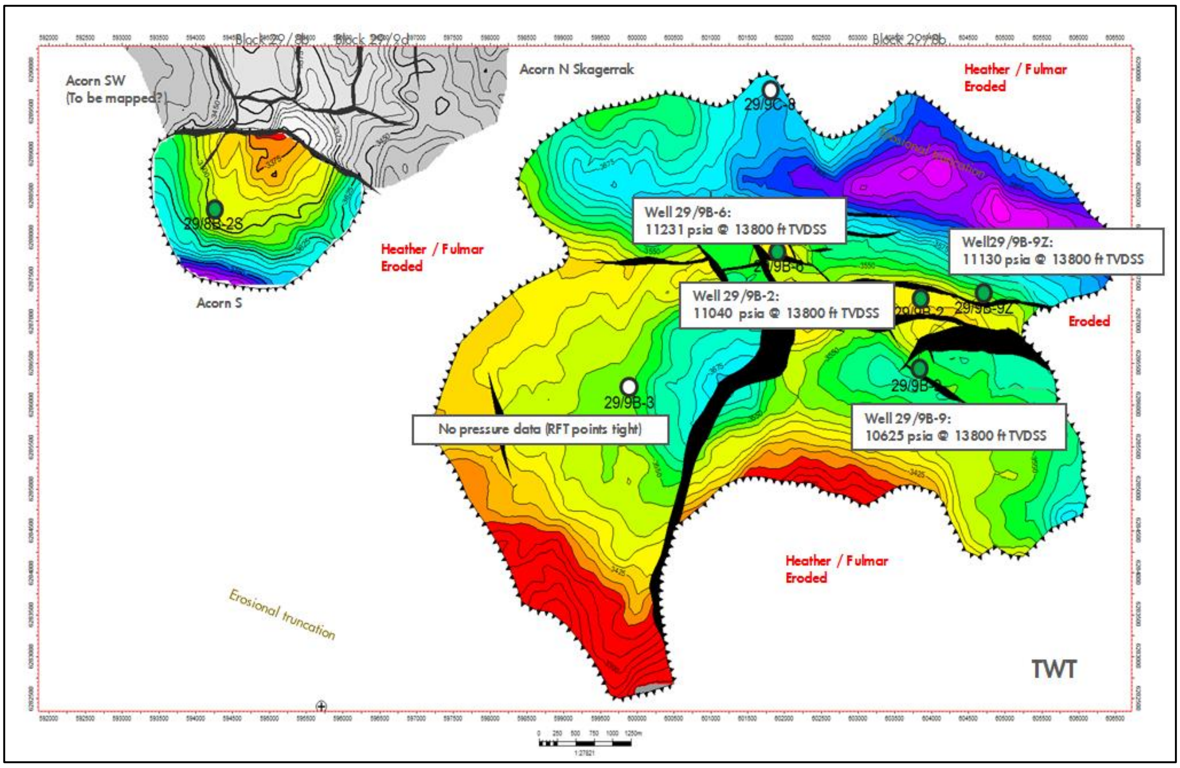


Figure 50 Beechnut field TWT Map with initial pressure per wells at datum depth

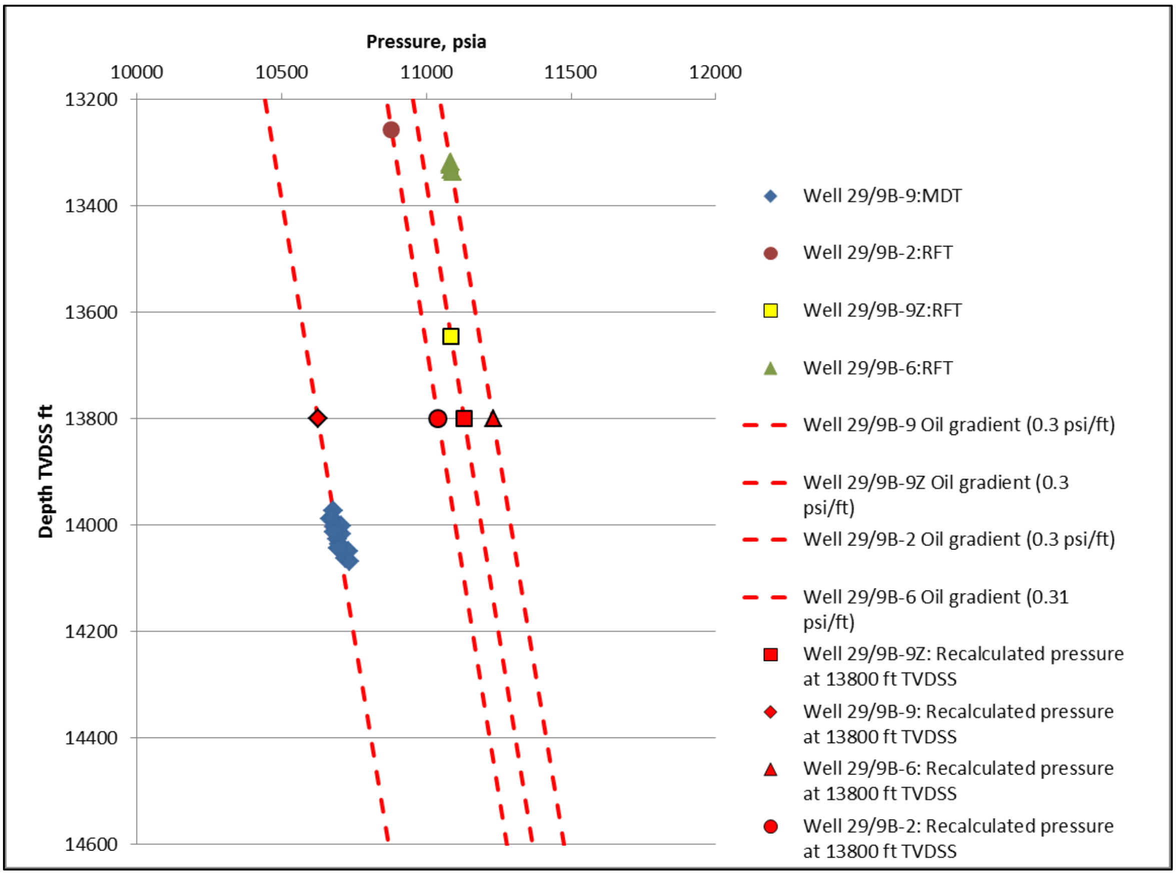


Figure 51 Initial pressure per well

3.4 Structural Modelling

3.4.1 Modelling Objectives

- Provide a visualisation tool to examine subsurface uncertainty such as reservoir structure, spill points, fluid contacts etc.
- Capture different realisations of the Fulmar reservoir geometry
- Comparison of volumetric changes since the 27th Round
- The model has ***not*** been used to calculate the in-place ranges of the Beechnut prospects, this was conducted by UIX using their workflows
- ***No*** property modelling has been conducted, deterministic volumes have been calculated using average values from probabilistic ranges
- Static model has ***not*** been exported from dynamic simulation

3.4.2 Model Data

	Beechnut Static Model Data
Type	Name
Seismic	Final_Stack_TOMOML_8B_final_SC_AVC8B_PreZ.vt
Seismic	Final_Stack_TOMOML_AVC2_PreZ.vt
Seismic	Final_Stack_TOMOML_HECATE_1_5_50_90_AVC_PreZ.vt
Horizon	Base_Kim_hybrid_model__P34_z
Horizon	BUJ_TomoML_bcu1_89x_m14362_Z
Horizon	Top_Pre_Rift_AL_Final_IrapClassicAscii.txt
Horizon	Top_Pre_Rift_Z_Final_AL_BeechnutSouth_ConstantThickness_Irapclassic.txt
Faults	BNAS_Faults
Wells	29/9B-9, 29/9B-9z, 29/9B-2, 29/9B-6, 29/9B-3, 29/9C-8
Tops	AL_TOPS_12FEB15
Logs	JOINED CURVES - GR
Logs	JOINED CURVES - RES_MED & RES_DEP
Logs	JOINED CURVES - NEU
Logs	JOINED CURVES - DEN
Core	Wells 29/9b-2, 29/9b-6, 29/9b-9 & 29/9b-9z

Table 26 Model Data Summary

3.4.3 Structural Framework

The Beechnut field is structurally complex and contains numerous isolated compartments. This is indicated from both geochemical and pressure data. Well test analysis also detects barriers, assumed to be nearby faults.

Faulting is normal and related to the Jurassic rifting of the North Sea. There are two fault trends across the field, North to South and East to West. The largest fault in the field runs North-South and separates what is considered “Beechnut East” and “Beechnut West”. This fault probably existed early during the deposition of the Fulmar as the down thrown side (West) appears to have always been deeper and lacking in deposition.

The East-West trending faults are smaller but more numerous. The faults represent crestal collapse of the structural high in the centre of Beechnut trending in the same direction. As the faults developed during the syn-rift they have elongated, breached relay ramps and connected with each other creating a complicated linkage of stepped faults.

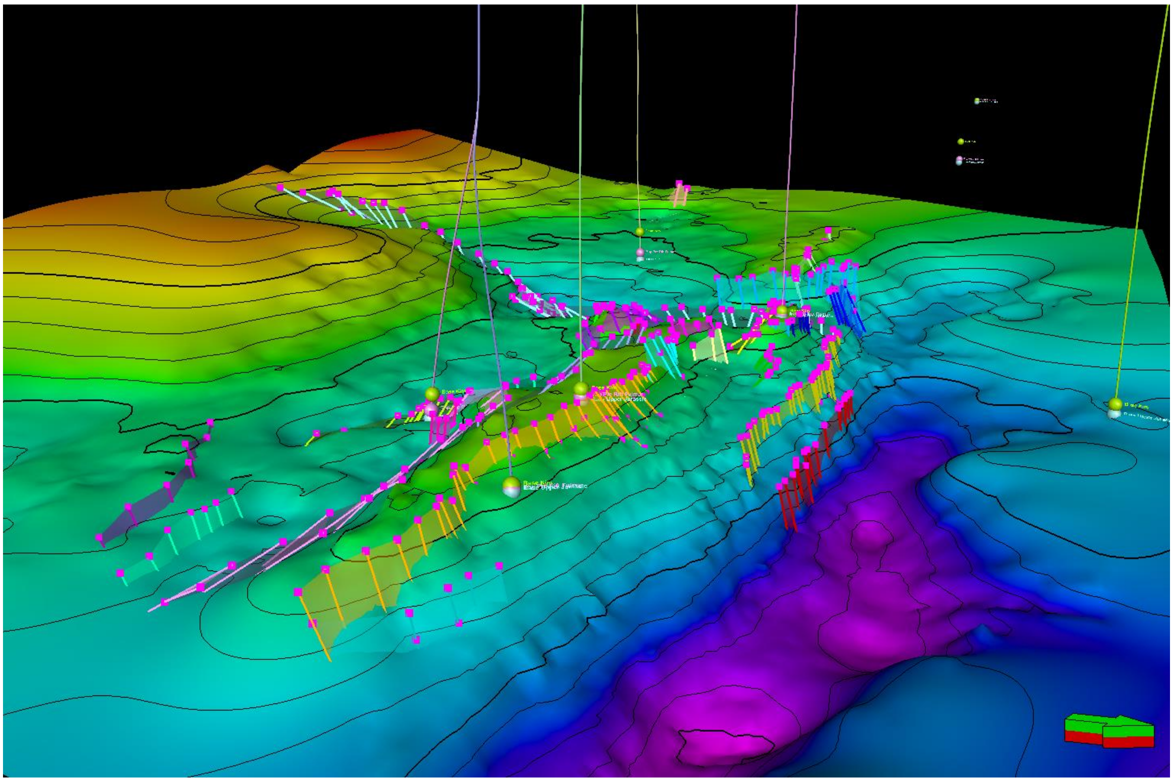


Figure 52 3D View of Fault Pillars and Plane in Petrel

The Beechnut structural grid is designed to incorporate the modelled faults and create major structural segments with the smoothest possible grid. The large faults were used to create segments which can be used later to create different structural compartments and allow variation in fluid contacts. It also allows for later detailed evaluation of the volumetrics on a sector by sector basis. Cells are typically 50m x 50m and the total number of cells in the static model is ~3 million.

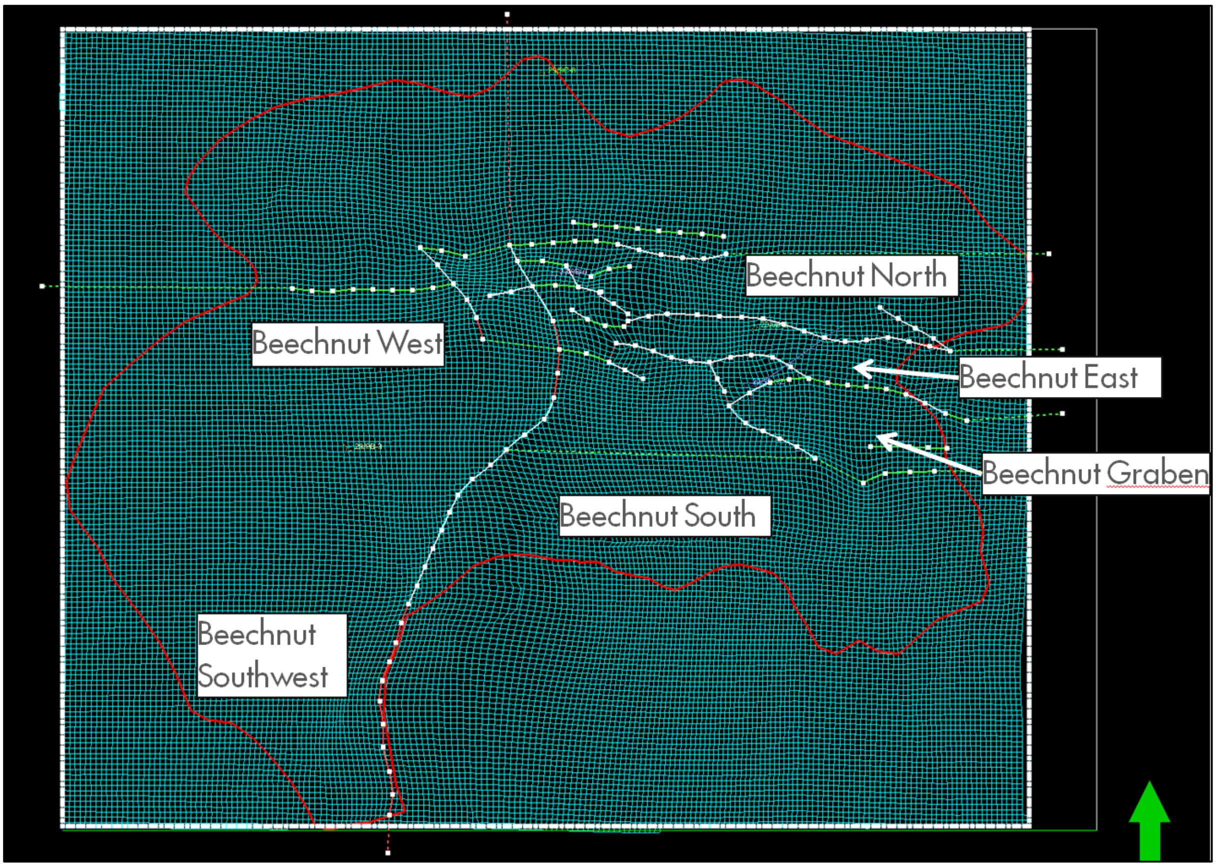


Figure 53 3D View of Cell Grid Layer & Model Segments

3.4.4 Horizon Modelling

Base Kimmeridge Clay and Base Upper Jurassic horizons have been included as the upper and lower limits of the model. Horizon interpretation breaks down close to the fault plane so a correction has been made using the fault-horizon lines in Petrel. Based on the structural-deposition model the thickness of the Pre-Rift fulmar is kept constant across the fault plane, as deposition predates faulting. Any thickening occurs in the Syn-Rift fulmar and this is more evident in the thicker, deeper sections.

Base Kimmeridge Clay:

- Base_Kim_hybrid_model_P34_Z_1000

Base Upper Jurassic:

- BUJ_TomoML_bcu1_89x_m14362_Z_1000

The “Fulmar” section between the Base Kimm. and the BUJ (Base Upper Jurassic) is subdivided into a Pre-Rift and Syn-Rift zones. The zones are defined based on the understanding of the depositional impact created by the two separate structural periods during the Fulmar.

During the modelling process two separate top Pre-rift horizons were considered, which represented different depositional models for the good quality Fulmar. The Wedge Model represents a system where the current erosional boundary is the same are the basin edge and the Fulmar thins onto this line. The Constant Model represents a more uniform thickness of Fulmar deposited over the area which is subsequently uplifted and eroded to give the current extent of the reservoir. Given the current structural understanding the Constant thickness model is preferred and carried forward for modelling.

Pre-Rift Fulmar Wedge:

- Top_Pre_Rift_AL_Final_IrapClassicAscii.txt

Pre-Rift Fulmar Constant:

- Top_Pre_Rift_Z_Final_AL_BeechnutSouth_ConstantThickness_Irapclassic.txt

As no logs upscaling or property modelling is planned a simplistic 100 layers was created between the Base Kimm. and the BUJ, with 40 layers in the Pre-Rift and 60 layers in the Syn-Rift.

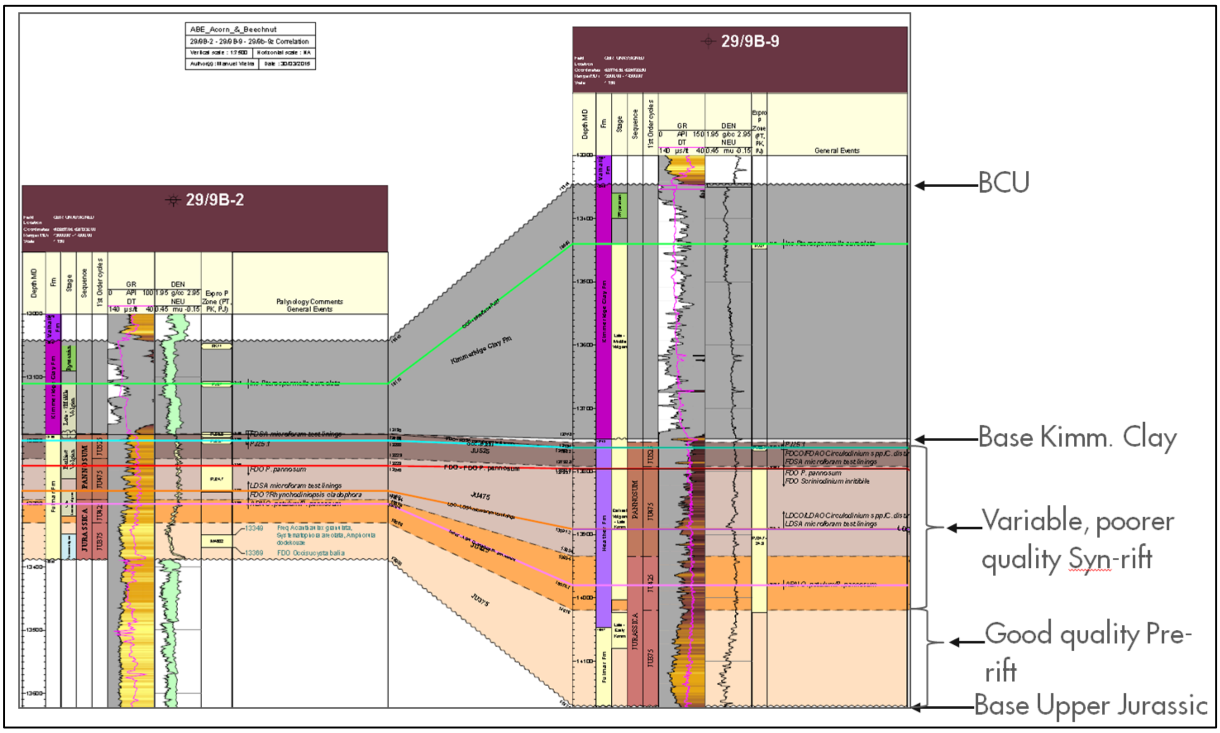


Figure 54 Model Stratigraphy & Zonation

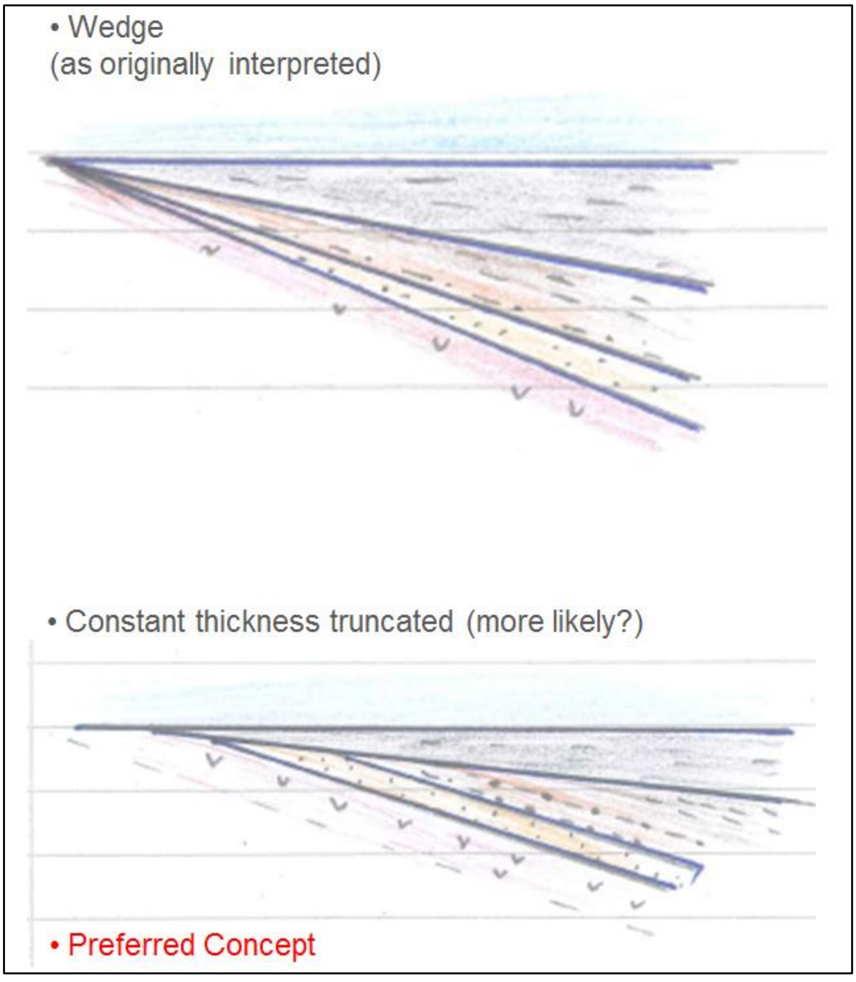


Figure 55 Different depositional geometries of the Pre-Rift Fulmar

3.4.5 Property Modelling

Although no property modelling was conducted deterministic volumes were created based on well averages and property ranges interpreted acros the field. Variation in the quality of the Pre-Rift Fulmar is observed in the well data across the field so a depositonal model was created to interpret these trends across the rest of Beechnut. The greatest influence on sand quality is assumed to be water depth, with the shallowest areas of the basin having the highest energy due to wave action and thus the cleanest sand. As the basin deepens this upper shoreface / beach sand degrades into heterogeneous lower shoreface and eventually into non-reservoir marine shale.

The central crest and Southern flank of Beechnut East are interpreted to have been the shallowest areas during deposition which is supported by evidence from the 29/9b-2 well. Shallow sands are clean and homogeneous but have also been improved by dissolution of sponge spicules (often found in shallow marine environs).

Beechnut West and the Northern flank are assumed to have been the deepest areas during deposition which is supported by the lack of reservoir present in the 29/9b-3 and 29/9c-8 wells.

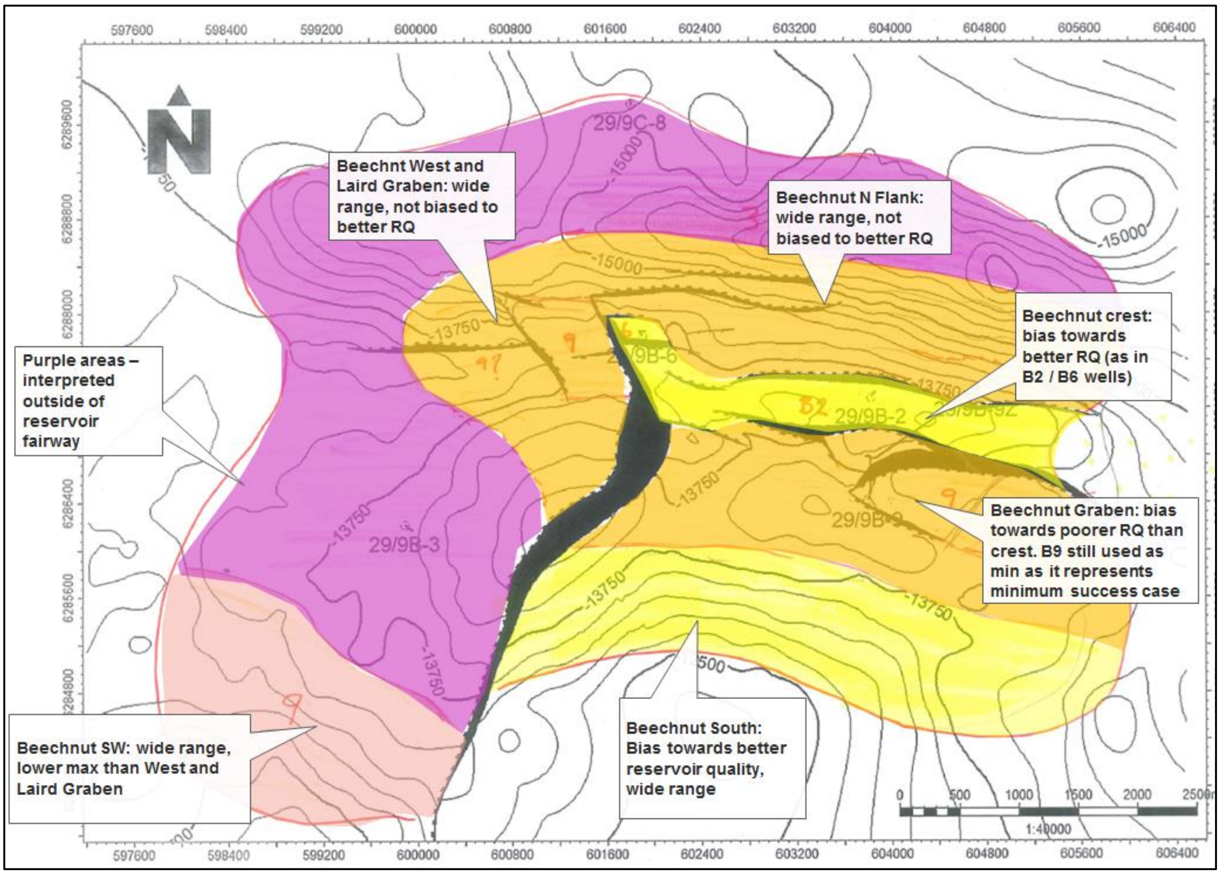


Figure 56 Fulmar Pre-Rift reservoir variations due to deposition and structure

3.5 Material Balance Modelling

3.5.1 Objectives and Approach

Beechnut reservoir is represented by homogeneous Fulmar sand, separated into several fault blocks (Beechnut East, Beechnut West, Beechnut South etc.) by sealing faults. The presence of sealing faults is supported by pressure differences observed in Beechnut E&A wells (see section Reservoir Pressure) and also results of Beechnut well tests interpretations.

Taking into account the field geology (homogenous isolated reservoirs without presence of any stratigraphic compartmentalization) a decision was made to use material balance approach for Beechnut field production forecasting.

A material balance models for each fault block were built. One horizontal 800m length production well is planed each development target. In order to take into production performance of Beechnut development wells Prosper models for each development target were built and connected to MBAL models.

3.5.2 Initial Volumes in Place

Initial in place static volumes range (P10-P50-P90) was calculated by UIX (STEP 3). Material balance models were built for Beechnut East, Beechnut North, Beechnut South faults blocks and based on un risked volumes.

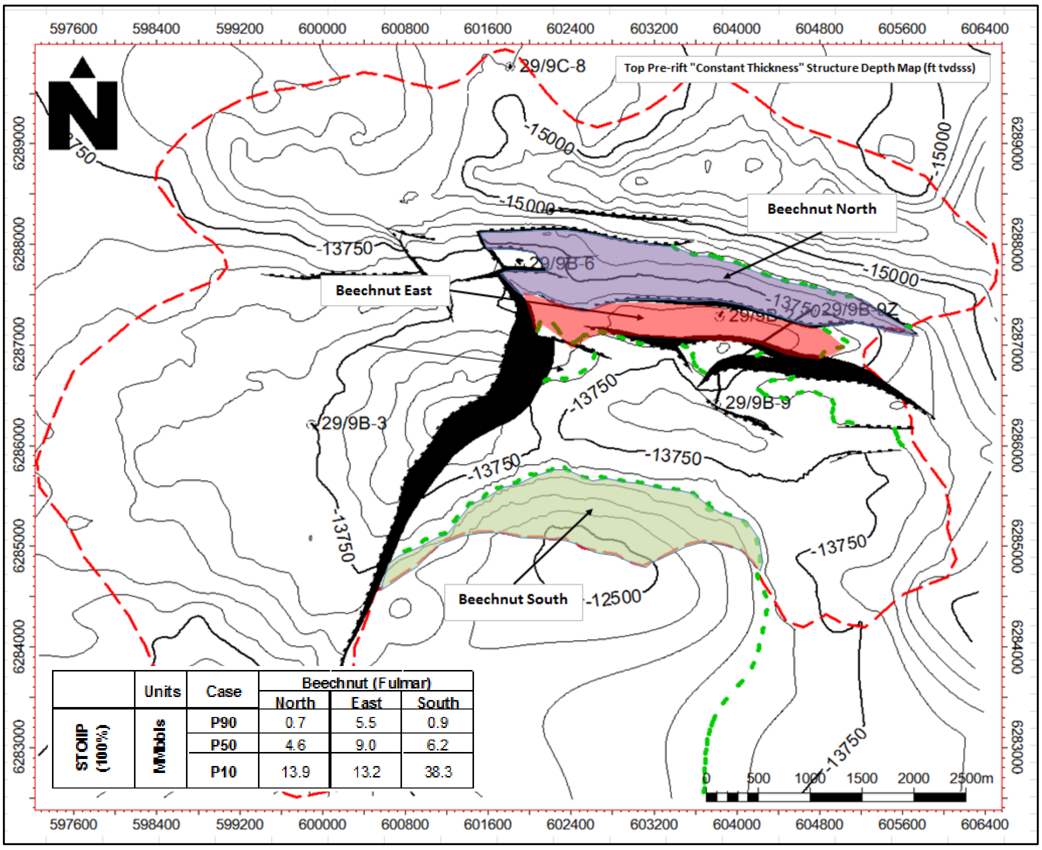


Figure 57 Beechnut Development Targets

3.5.3 Reservoir Fluid Properties

Beechnut simulation model is based on well 29/8B-2 history match PVT model. The model was built on well head sample 810292 composition bases and history matched against lab experiments in PVTSim package. Black oil tables at flash separator conditions were exported for production forecasting: GOR of 699 scf/bbl and Bo of 1.35 rb/stb.

Water PVT properties refer to water salinity of 200000 ppm.

3.5.4 Pore Volume Compressibility

Acorn North's pore volumes compressibility range 6-16 microsips was used for Beechnut modelling. The range in line with rock compressibility values measured from Beechnut core samples. A mean value of 11 microsips was used for material balance modelling.

3.5.5 Well Test Analysis

Three E&A Beechnut wells were tested: 29/9B-2, 29/9B-9 and 29/9B-6. Production performance of the wells varies in a wide range: initial oil rates at the highest choke vary in a range from 1173-7266 bbl/day. That difference in production performance caused by variation of reservoir quality of fulmar sand in Beechnut field between fault blocks.

The most productive well is well 29/8B-2. The well was tasted at the highest rates of 7266 bbl/day and pressure draw down around 35%. The high well productivity caused by good reservoir quality of fulmar sand in the area: well KH around 1100 mD*ft.

Well 29/8B-9 and 29/8B-6 were tested at high pressure draw down around 67%, however low oil rates were achieved 2434 bbl/day and 1203 bbl/day respectively.

Production performance of well 29/8B-6 is affected by limited volumes: well located in an isolated; also it has a poor reservoir quality: core data analysis indicate presence of cementation in the rock, which is not seen on well 29/8B-2 and well 29/8B-9 core samples.

Low well 29/8B-9 production performance, caused by poor reservoir quality of fulmar reservoir in the tested area. Well test interpretation results give low well KH 178mD*ft, which is in line with petrophysical evaluation, suggesting poorer reservoir quality in the well in comparison to well 29/8B-2. Core data analysis indicate that fulmar reservoir in vicinity of well 29/8B-9 is the same homogenous sand like in well 29/8B-2, but only represented by much poorer reservoir quality.

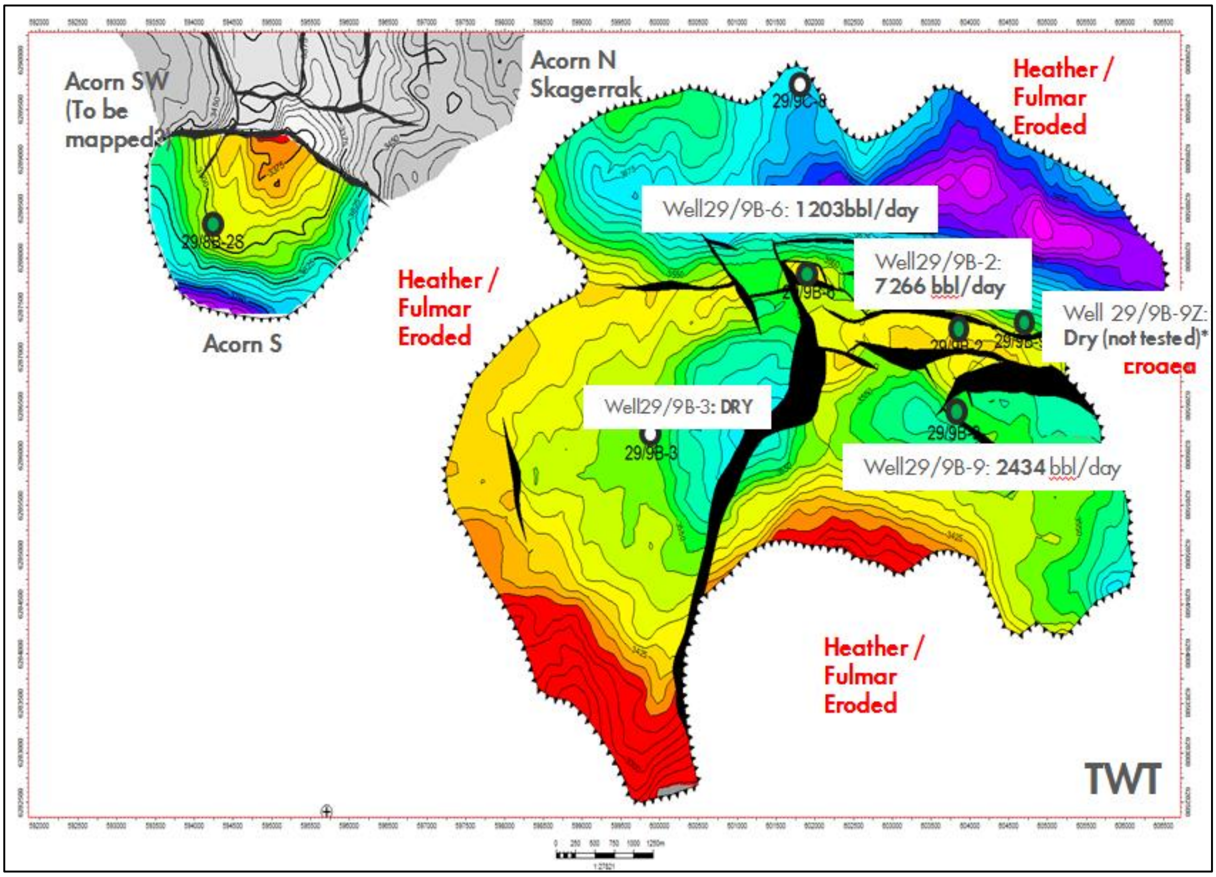


Figure 58 Beechnut TWT Map with Well Test Results

Well name	Zone	Test, MD ft	Choke size	Oil Rate, bbl/day	GOR, scf/bbl	BSW, %	KH, mD*ft	Skin	PI, BOPD/psi
29/9B-2	Fulmar	DST3: 13200-13240; 13310-13380	32/64" (14 hrs)	5194-5794	384-453	0	1128	1.6(high perm); 2.1 (total thickness)	0.8
			56/64" (7 hrs)	6794-7266	511-576	0			
29/09b-6	Fulmar	DST1: 13336-13421	20/64"(11 hrs)	680-571	637	0.5	40	0.3	0.08
			32/64" (2 hrs)	958-1203		0.1-0.5			
29/09b-9	Fulmar	DST1: 14085-14190	72/64": Flow period 2 (~6 hrs)	2145-2430	432-477	0	178	0.4	0.4
			72/64": Flow period 5 (~12 hrs)	1785-2434	407-503	0			
29/09b-3	Fulmar	N/A	**No flow/No reservoir**						
29/09b-9Z	Fulmar	N/A	**No flow/No reservoir**						

Table 27 Beechnut Well Test Summary

3.5.6 Aquifer

No aquifer support is expected for Beechnut development fault blocks (Beechnut East, Beechnut South, Beechnut North), due the fact that each fault block represents an isolated tank limited by sealing faults (different initial pressure in each fault block see initial pressure section).