UKCS Licence P2201,
Blocks 211/13c and 211/18c
Relinquishment Report

October 2016

Contents

1 Introduction

EnQuest gives permission for the publication of this document.

This report documents the relinquishment of licence P2201, UK Blocks 211/13c and 211/18c, awarded to EnQuest Heather Ltd (EnQuest) and Ithaca Energy UK (Ltd) (Ithaca) in 2014 as part of the UK 28th licence round. The location and extent of the licence area can be seen in Figure 1.

A brief summary of the licence is presented in Table 1.

Licence Number	P2201
Licence Round	28th
Licence Type	Traditional
Block Number(s)	211/13c & 211/18c
Operator / Partners (%)	EnQuest Ltd (60%; operator) Ithaca Energy (UK) Ltd (40%)

Table 1: Licence Summary

2 Licence Synopsis

The P2201 licence was awarded to EnQuest and Ithaca in the 28th UK offshore licence round with a start date of the 1st of December 2014. At the time of application five prospects/leads were identified within the application area.

Post award evaluation continued, on the 23rd of October 2015 a partial relinquishment of the licence was carried out with the non-prospective areas to the north and south relinquished. This focused the evaluation with the licence acreage reduced from 112km^2 to 68km^2.

3 Work Programme Summary

Drill-or-drop provision

The Licensee shall either:

a) Drill one well to 3475m or 45m into the Statfjord Formation, whichever is the shallower, or:
b) Elect to allow the licence to automatically cease and determine pursuant to Clause 3.

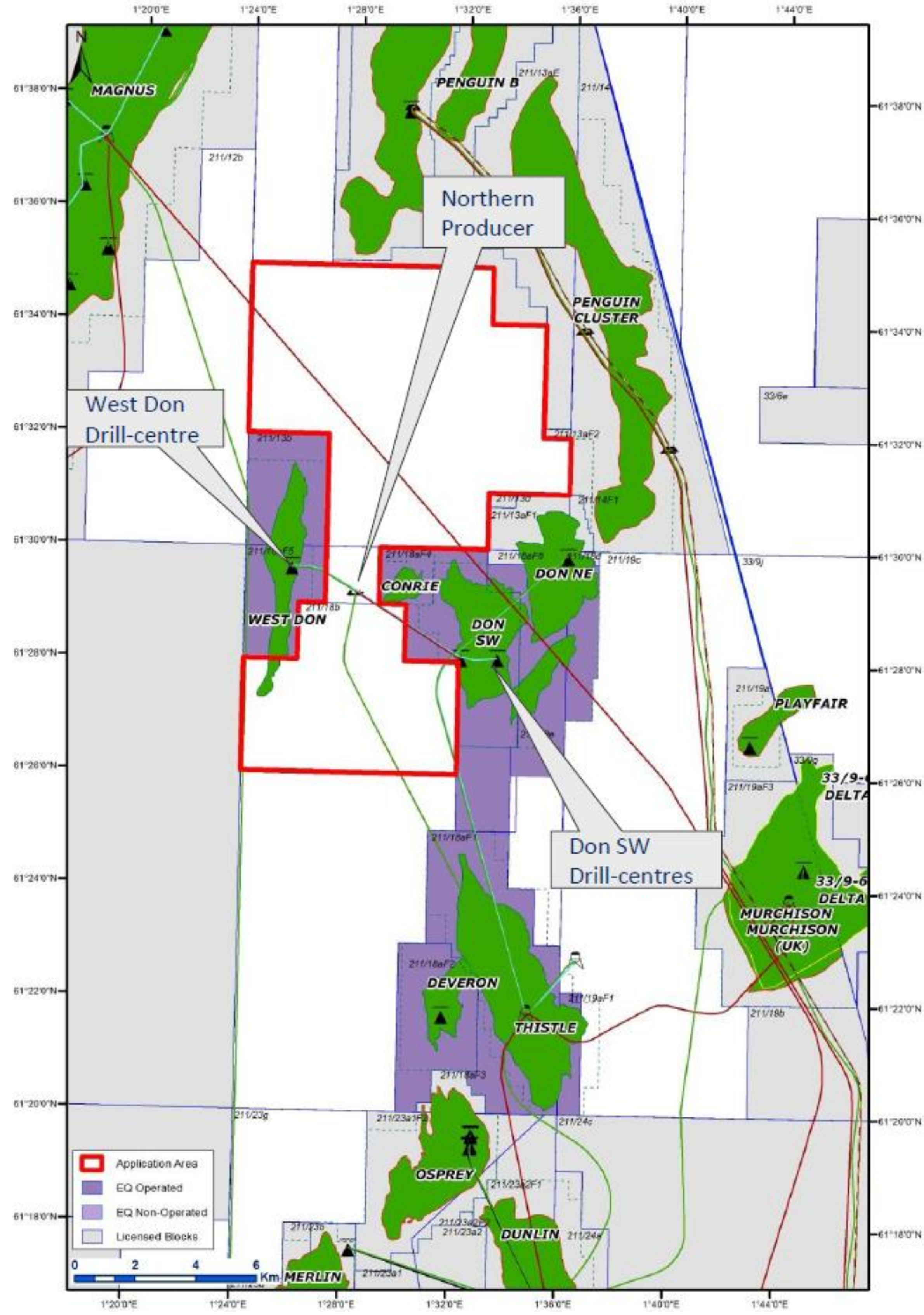

Figure 1: Licence P2201 Location

4 Database

4.1 Well Database

EnQuest has access to an extensive well database in this region as shown in Table 2, which includes well reports, composite logs and wireline log data. All the relevant released well data in the surrounding acreage has been acquired from CDA and analysed.

Well	Year Drilled	Status	Target	TD Formation	Results
211/13-1	1974	P&A Gas & Condensate	Triassic/Jurassic Sands	Cormorant Fm.	Penguin B (Helena) discovery well. The Cormorant Formation tested at 10.3mmscf/d gas and 3,300bbls/d condensate.
211/18-5	1974	P&A Dry Hole	Triassic/Jurassic Sands	Banks Group	Typical Brent section penetrated. Very weak shows in uppermost Brent and none for the majority of the succession. No noted shows in the Banks Group.
211/13-3	1975	P&A Oil well	Jurassic Sands	Cormorant Fm.	Penguin A discovery well. Oil found in the Magnus and Ptarmigan Sandstone Members.
211/18-9	1975	P&A Oil Discovery	Brent Group	Banks Group	West Don discovery well. Brent Group oil bearing and tested at 3623bbl/d oil ~31.6 ^{o}API
211/18-10	1975	P&A Dry Hole	Brent Group	Banks Group	Brent group thin due to erosion.
211/18-12	1976	P&A Oil Discovery	Brent and Banks Group	Banks Group	Don discovery well. Tested 2800 bopd, 36.6 ^{o}API. Water bearing Banks Group.
211/18-13 (N01)	1976	Oil Discovery Development Well	Brent and Banks Group	Banks Group	Don NE discovery well. Tested 9100 bopd, 40.3 ^{o}API. OWC 11305-11,340 ft TVDss. Water bearing Statfjord Fm. Completed as development well 1989.
211/13-5A	1977	P&A with Oil Shows.	Jurassic sands	Cormorant Fm.	Thin and poorly developed Magnus & Ptarmigan Sands found. In addition Brent Group was very thin due to faulting. Substantial Banks Group section penetrated. The Magnus & Ptarmigan Sands in addition to the Banks Group had poor-moderate oil shows.

Well	Year Drilled	Status	Target	TD Formation	Results
211/18a-23	1982	P&A Oil Discovery	Brent Group	Dunlin Group	144 ft Brent oil column to OWC @ 11,720 ft TVDss. Tarbert Formation tested @ 728 bopd.
211/18a-24	1982	P&A Oil Discovery	Brent Group	Banks Group	183 ft oil column to OWC @ 11,516 ft TVDss. The Banks Group was tested at 1661bopd and the Brent Group at 805bopd before and 4,435bopd after fracturing
211/13a-8	1984	P&A Dry Hole	Brent and Banks Group	Cormorant Fm.	Water wet Brent and Banks Groups.
211/18a-8Z	1984	P&A Oil	Brent Group	Dunlin Group	Oil bearing Brent Group. Tested @ up to 7160 bopd ~42 ^{o}API oil.
211/14a-2Z	1986	P&A Oil	Brent and Banks Group	Dunlin Group	133 ft Brent hydrocarbon column to ODT 11,310 ft TVDss. Tested at 4800 bopd & GOR of 4,760 scf/bbl. 40 ft Banks Group oil column to 11,694 ft TVDss.
211/14-3	1989	Suspended(?) Oil and Gas	Brent and Banks Group	Cormorant Fm.	Penguins Cluster appraisal well. Oil and gas found in the Brent and Bank Group. On test the Brent produced 2922stbo/d and 5.7MMscfg/d, the Banks Group produced 641stbo/d and 10.7MMscfg/d.
211/13b-11	1990	P&A Oil well	Brent Group	Cormorant Fm.	Brent Group oil bearing and tested at 7597bbl/d. Minor shows in the Banks Group.
211/12b-15	1992	P&A Dry Hole	Magnus Sandstone Member	Heather Fm.	A substantial thickness of Magnus and Ptarmigan Sandstone Members were penetrated. Limited oil shows were reported.
211/18b-25	1992	P&A Dry Hole	Jurassic Sands	Banks Group	Brent and Banks Groups penetrated. Limited shows in the Brent Group & none in the Banks Group.
211/18a-S15	2014	Development	Brent and Banks Group	Cormorant	Well encountered oil in Brent and Statfjord. OWC (Brent) at 11,547ft TVDss.

Table 2: Offset well data summary

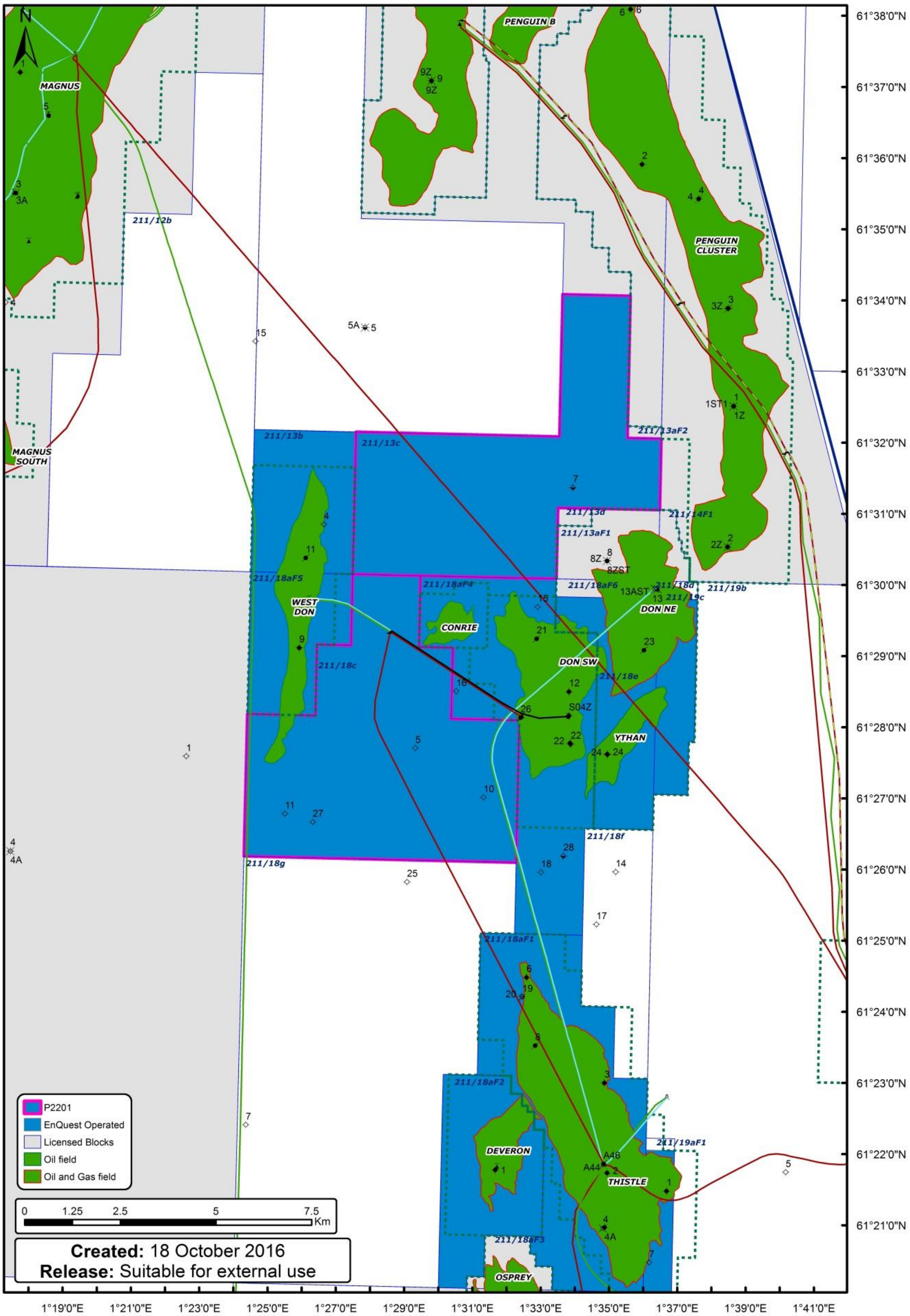

Figure 2: Well Database Map

4.2 Seismic Database

The 3D seismic database that EnQuest has used for this evaluation and application is detailed in Table 3.

EnQuest and Ithaca initiated a reprocessing of 250 sq kms of data from Western Geco 1997 and 1998 vintage data. This was reprocessed to Pre-stack depth migration using an Anisotropic Kirchhoff algorithm (Figure 3). EnQuest supplied velocity boundaries to geologically constrain the velocity model. The reprocessed volume also benefited from improved multiple elimination, better fault positioning and higher levels of signal/noise. Spectrally Blued and Colour inverted volumes were computed internally for both PSTM and PSDM volumes.

Survey Name	Volume Description	Data types available	Year	Areas Covered	Total (Km^2)	Block coverage (Km^2)
Quad 210/211 & Penguins Repro 2014	WGC Reprocessed PSTM and PSDM	Full, angle stacks, PSTM, and PSDM	Western Geco 1997/1998	Dons area	250	72
SW Don, West Don, NE Don SIP 2011	Merged and reprocessed 1993 BP and 1997 Western Geco 3D Data Sets reprocessed by SIP in 2011	Full, angle stacks, PSTM, and PSDM	BP1993 Western1997 Merged and reprocessed 2011	Dons area	249	50
Western Geco Quad 210&211 1997, 1998 data	Licenced WGC 3D seismic dataset reprocessed in 2007 and 2008	Full angle stacks and PSTM	Western Geco 1997/1998 reprocessed in 2008	Blocks 211/12,13,17,18 (part of)	428	46
VER CNS07 (Q15 Ph 1)3D	Licenced CGG 3D seismic data acquired in 1996	Full Stack	CGG processed 1996	Block 211/19	153	0
Western Geco Penguin 1998	Licenced Western Geco 3D seismic data acquired in 1998	Full Stack	Western Geco processed 1998	Blocks 211/12,13 (part of)	85	13
PGS Megamerge	Licenced PGS Merged 3D Seismic dataset - various sources and vintages	Full Stack	Various	Regional Coverage		112

Table 3: Seismic Data Summary

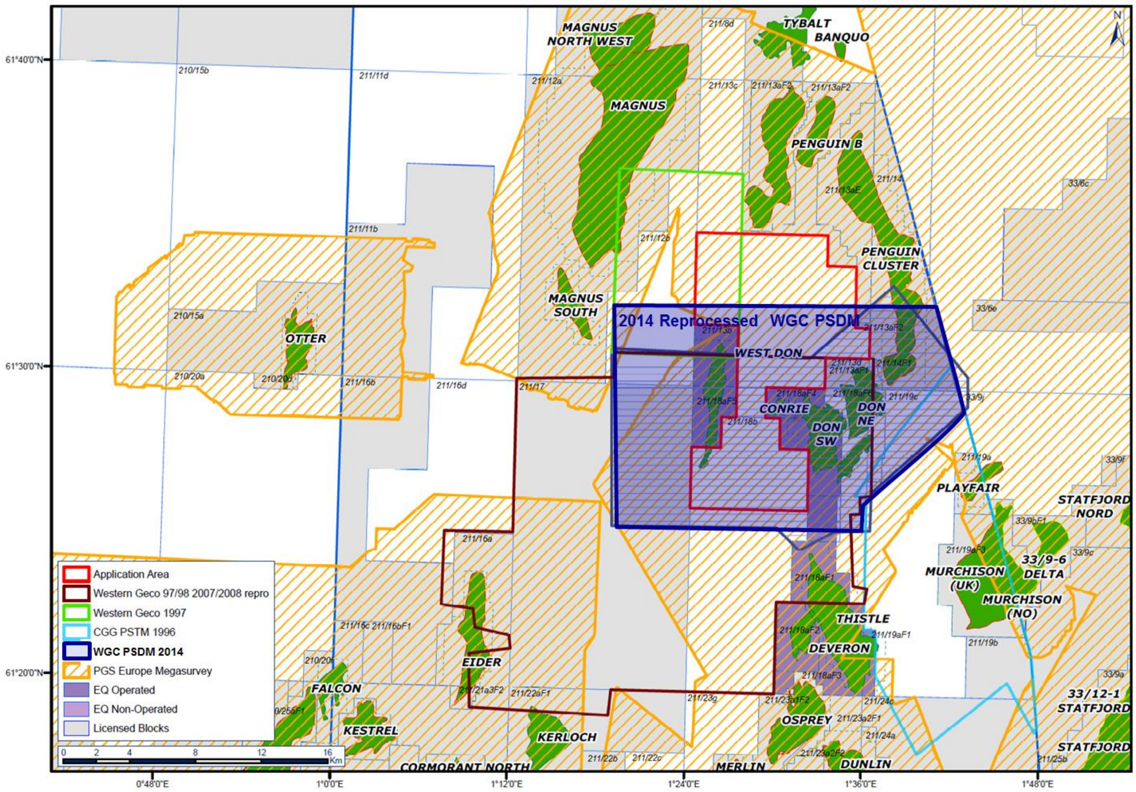

Figure 3: Seismic Database

5 Regional Overview

5.1 Regional & Tectonic Setting

Structural Setting

Regional Tectonics

The study area is situated in the northern most part of the East Shetland Basin. The East Shetland Basin is a half graben consisting of Permo-Triassic and Jurassic tilted fault blocks overlain by Cretaceous and Cenozoic sediments. The basin is bounded to the west by the Palaeozoic East Shetland Platform, to the east and south by the Viking Graben, where north-south faults predominate, and to the north by the ENE-WSW trending Magnus Embayment in which NE-SW faults predominate. The northern North Sea formed as result of multiple stretching episodes during the Mesozoic, with the two main rifting episodes dated as Permo-Triassic and Jurassic, followed by episodes of passive post thermal subsidence in the early-middle Jurassic, and the Cretaceous-Cenozoic respectively. The Permo-Triassic rifting was characterised by north-south trending faults, this period of rifting was followed by a phase of post-rift thermal subsidence in the early and middle Jurassic. The Permo-Triassic rifting episode is evidenced by variability in the distribution of Palaeozoic sediments in addition to thickness variations within the Cormorant Formation from one fault block to another. In addition thickness variation within the Banks Group indicates some of this faulting may have locally extended into the Lower Jurassic epoch. The second Mesozoic rifting episode affected the northern North Sea during the middle / late Jurassic to early Cretaceous times.

This phase of rifting strongly overprinted the earlier phase of Permo-Triassic rifting. This phase of rifting can be demonstrated by the development of an extensional fault system, which became active towards the end of the Brent Group to early Heather Formation deposition, as evidenced by the syn-rift thickening of the Heather and Kimmeridge Clay formations in the palaeo-lows and their corresponding thinning onto palaeo-highs. This trend is rarely duplicated in the underlying Brent Group, however locally it is. An example is provided by West Don and the Thistle Field, where the Brent Group can be demonstrated to show some depositional thinning onto footwall crests while an erosion truncated Brent Group is present at the crest of the Halibut High. Post-rift thermal subsidence continued from the Cretaceous through Cenozoic.

Local Structure

Seismic interpretation illuminates the structural complexity of the Greater Dons area. The predominant structural regime is extensional, with throw on planar, normal faults, displaying several significant trends, Figure 4. The area is dominated by NNW-SSE trending faults such as those bounding the Dunlin, Thistle and Penguin C & D Fields. Almost perpendicular to this are large NE-SW trending faults which define the footwall highs of the Murchison, Statfjord Nord, and Thistle Fields. The NNW-SSE faults often terminate where they intersect the NE-SW faults, accommodating local footwall uplift, due to stress release, along the NE-SW extensional faults. The Don SW and NE accumulations are local footwalls, bounded by NNW-SSE faults, and developed against a NE-SW fault. This NE-SW fault links the Penguin Ridge to the north with the NNW-SSE trending Halibut High to the south, which is an extension of the NNW-SSE Thistle trend. Between the larger field defining faults, numerous smaller faults are seismically distinguished. Most do not substantially offset the reservoir and typically do not significantly impede fluid movement. However, significant fault offsets >150 ft often baffle and indeed confine the flow of injection water. For example in Don NE 100 ft of contact differential is accommodated on a NNW-SSE fault.

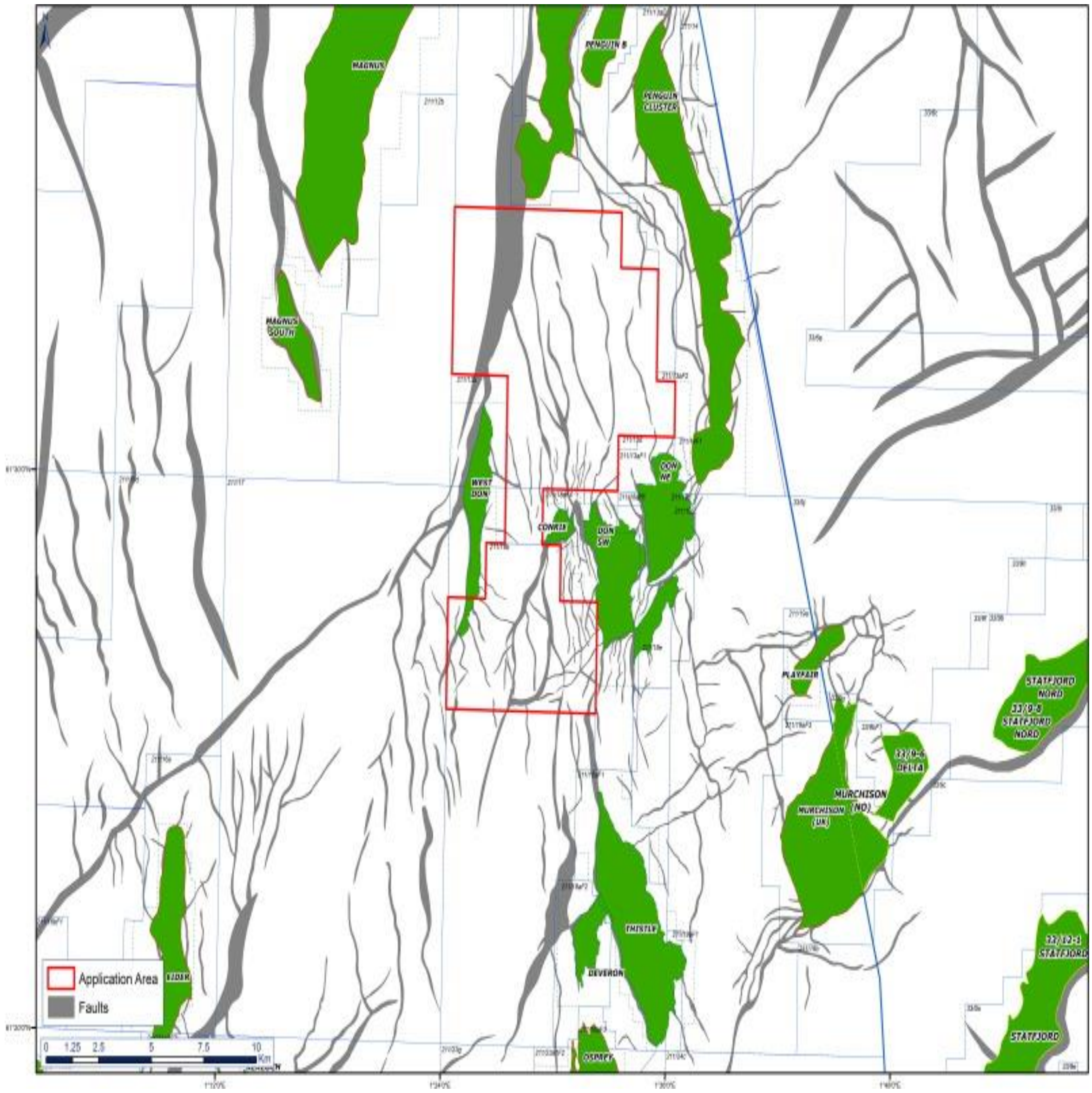

Figure 4: Structural Map of the Dons Area.

Stratigraphy

The stratigraphy for the Greater Dons Area spans from the Precambrian through to the recent. The following section outlines this stratigraphy and is shown in Figure 5.

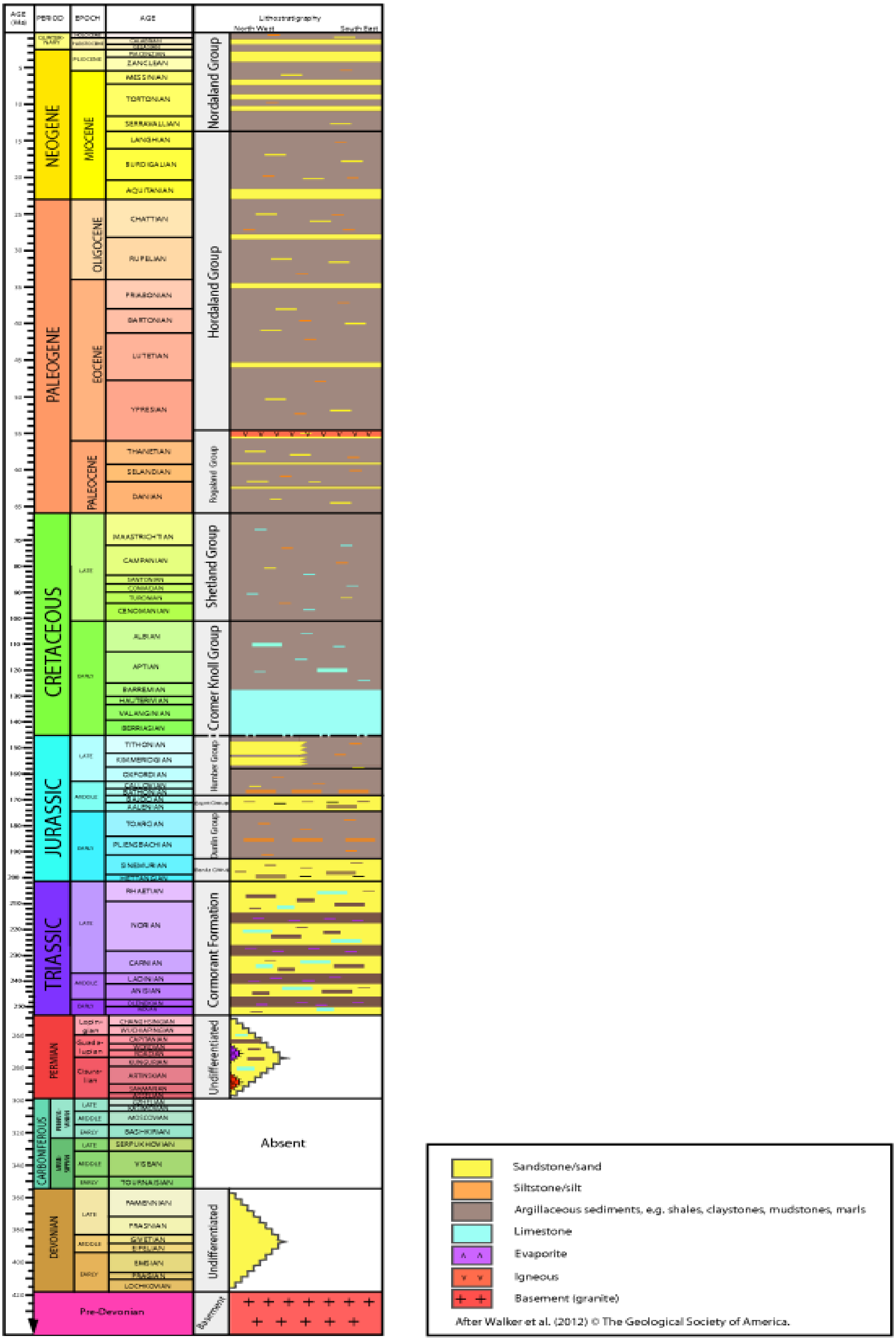

Figure 5: Stratigraphic Column for the Greater Dons Area

Precambrian - Early Palaeozoic

In the Northern North Sea, very few wells have penetrated the base of the Triassic sequence. The closest wells to the study area which did are outside the Greater Dons Area. The oldest lithology penetrated in the area is a granite which lies unconformably underneath Palaeozoic and Triassic sediments. The age of this granite is uncertain however it is evidently pre-Devonian.

Palaeozoic

The aforementioned crystalline basement is overlain, in some areas by Palaeozoic sediments. The Devonian sequence comprises tight red sandstones, likely of Old Red Sandstone affinity. No Carboniferous sediments have been penetrated in the area. Overlying the Devonian is a mixed sequence of rocks comprising Permian deposits. Lithologies include; clastic, carbonate, evaporite and igneous formations. These Permian sediments are believed to be of Rotliegend and Zechstein affinity. Palaeozoic sediments were only penetrated in the north of the study area (west and north of the Magnus Field). To the south around Eider, the Triassic unconformably overlies crystalline basement. Due to the limited number of wells which penetrated the pre-Triassic sequence, drawing any further conclusions is problematic.

Triassic

In some areas the Triassic sequence unconformably overlies crystalline basement while in others it conformably overlies the aforementioned Palaeozoic sediments. The thickest Triassic sequence was penetrated in the wells where the Triassic sediments overlie Palaeozoic sediments and not crystalline basement, therefore it would seem that the Triassic sediments continued to fill the Palaeozoic basins initially before being deposited over the crystalline palaeo-highs. The Cormorant Formation spans the entire Triassic period. These sequences of sediments were deposited in an arid continental environment as part of a regional scale distributive fluvial system. Cormorant Group lithofacies include; fluvio-lacustrine, flood-plain sands and muddy silts, the latter which is occasionally anhydrite cemented. The sands are compositionally immature, reflecting the fact that they are first cycle sediments and are often carbonate cemented.

Jurassic

The Jurassic period can be divided into four broad successions (Figure 6).

- The Early Jurassic sand dominated Banks Group
- The Early Jurassic shale dominated Dunlin Group
- The Middle Jurassic sand dominated Brent Group
- The Middle Jurassic-Late Jurassic shale dominated Heather and Kimmeridge Clay Formations (the latter also includes some arenaceous members)

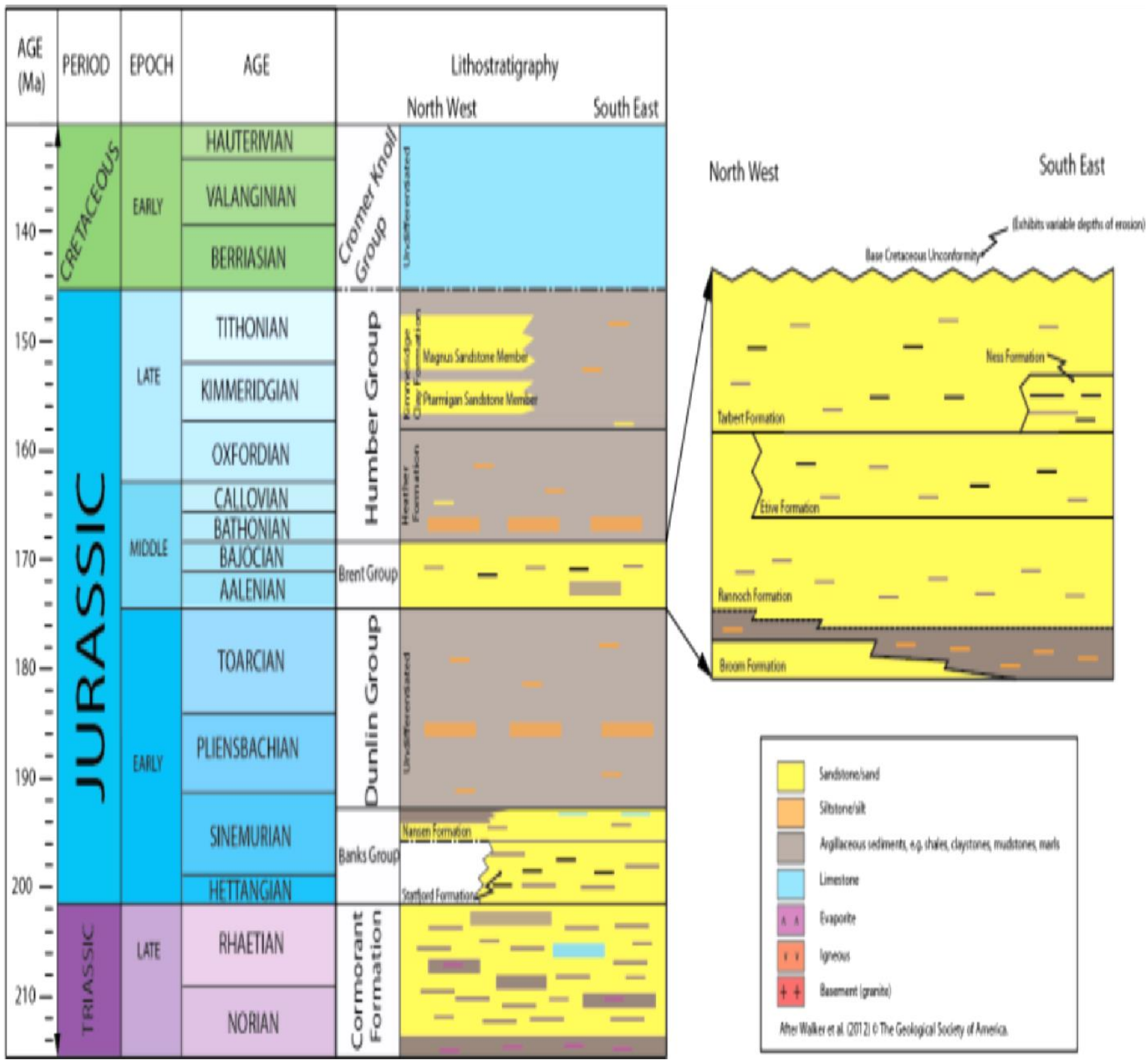

Figure 6: Stratigraphic Column for the Greater Dons Area. Expanded Jurassic Section

The Early Jurassic Banks Group is predominantly arenaceous and comprises two formations; the Statfjord and the Nansen. The Statfjord Formation comprises sandstones, siltstones, mudstones and coals reflecting deposition within fluvial channels and interfluvial floodplains. These deposits reflect a change from the arid climate in which the Triassic Cormorant Formation was deposited, to the semi-arid to humid climate prevalent during the Early Jurassic epoch, when the Statfjord Formation was deposited. In the western portion of the East Shetland Basin the Statfjord Formation is absent, the western limit of the Statfjord Formation, within the study area trends approximately N-S and lies in blocks 211/12 & 211/17 (Figure 7). The Nansen Formation predominantly comprises sandstones with subordinate siltstones and mudstones. It was deposited in coastal/fluvial channel-shoreface depositional systems and as such the Nansen Formation records a transgression over the Statfjord Formation. Within the Greater Dons Area the Banks Group varies in thickness from 45 to 407ftTVT.

The Dunlin Group is predominantly argillaceous and comprised of the Amundsen, Burton, Cook and Drake Formations. In the study area the Dunlin Group is predominantly comprised of mudstone with subordinate siltstones deposited in a deep marine environment. To the east of the Greater Dons Area, in the Norwegian sector, there are several sandstone packages developed within the Dunlin Group, which in some areas are prospective reservoirs, but this sand does not extend into the Greater Dons Area. The Dunlin Group represents a continuation of the transgression of the Nansen Formation over the Statfjord Formation. Within the Greater Dons Area the Dunlin Group commonly varies in thickness from 170 to 400 ftTVT.

The Middle Jurassic Brent Group is predominantly arenaceous, comprising the Broom, Rannoch, Etive, Ness and Tarbert Formations, shown in a regional well correlation over the Don Fields across the Halibut High to the Thistle Field (Figure 8). The Group comprises sandstones, siltstones, mudstones and coals, deposited in a delta-top & shoreface environment with some deeper marine systems represented in the Broom Formation and the Rannoch Shale (lower Rannoch Formation). As such the Brent Group initially records a regression from the deep marine Dunlin Group, this regression culminated in the deposition of the delta-top Ness Formation. The Tarbert Formation (and uppermost-Ness Formation) records a transgression over the Ness in which shore-face sediments were deposited. The Greater Dons area is considered to be located in a relatively distal situation in the Brent depositional fairway, and as a result the Ness Formation is absent in the northern part of the study area. The Ness Formation depositional boundary trends approximately E-W and lies between the Thistle and Dons Field, with well-developed Ness in the Eider, Thistle and Murchison Fields and no Ness Formation in the Dons, Penguins and Magnus Fields (Figure 9). North of the Ness depositional boundary an age equivalent shoreface succession was deposited which is attributed to the Tarbert Formation. The Etive Formation also thins considerably to the north, it is known to be absent just north of the Magnus Field, and is thought to be absent over the Penguins Cluster and Magnus Field. The Broom Formation is believed to be sourced from the basin margins, i.e. to the West, and within the study area the Broom is thickest in the NW, it thins rapidly to the SE and is absent in the Penguins Cluster and very thin in the Dons (NE & SW), Thistle and Murchison Fields, (Figure 10). Within the study area, where present, the Brent Group commonly varies in thickness from 250 to 500 ftTVT.

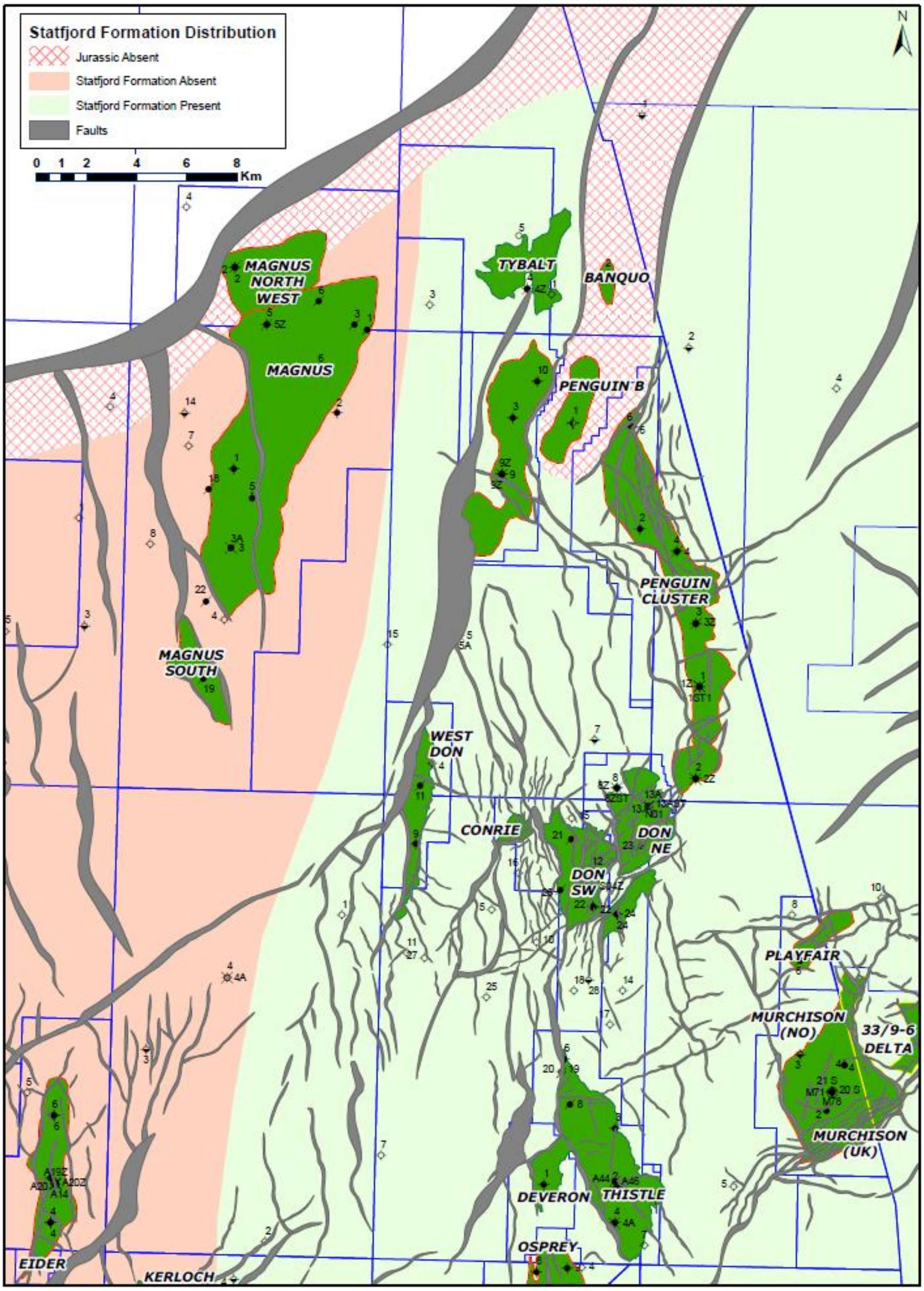

Figure 7: Greater Dons Area Statfjord Formation Distribution.

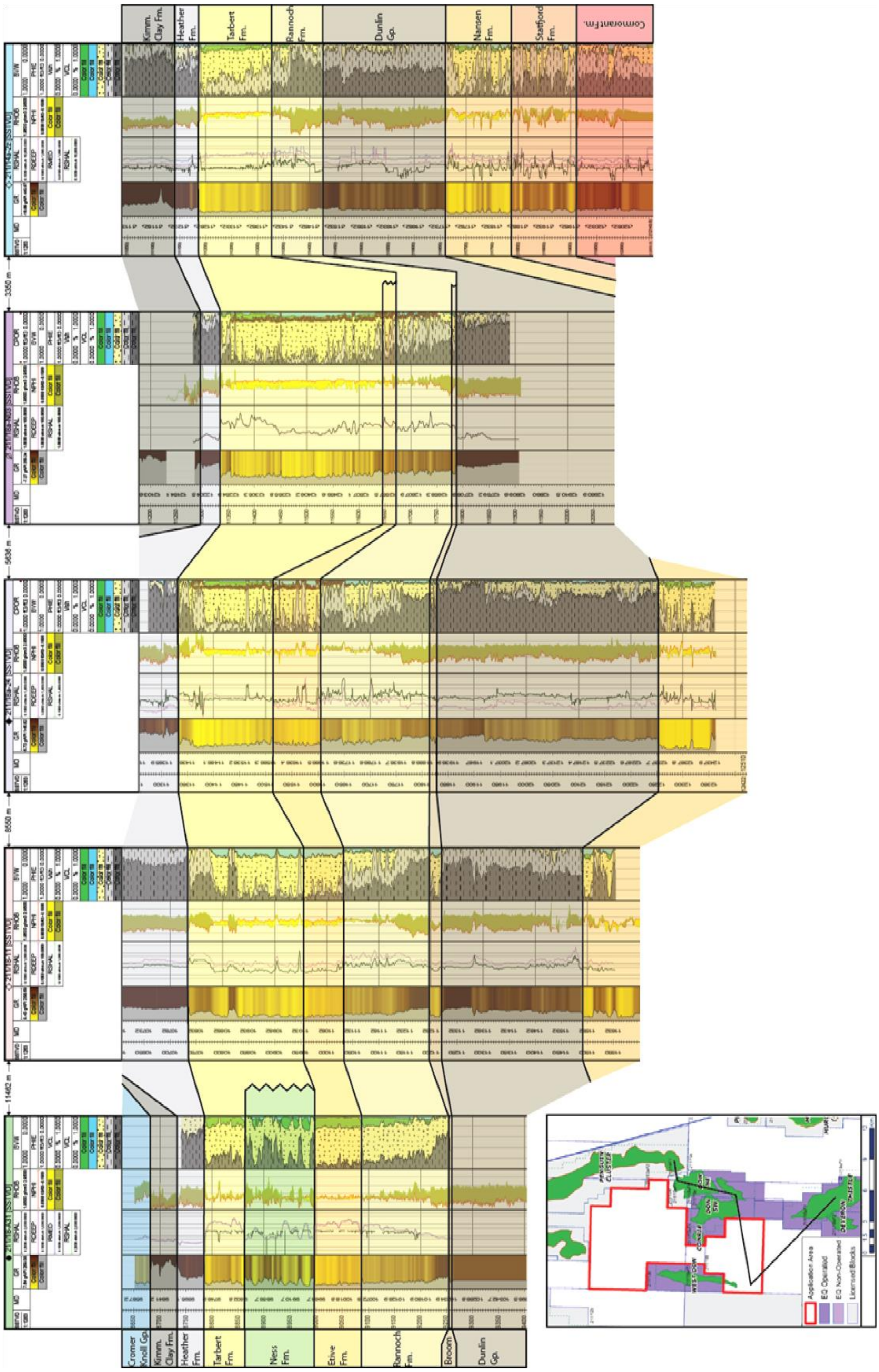

Figure 8: Greater Dons Area - Brent Correlation (N-S).

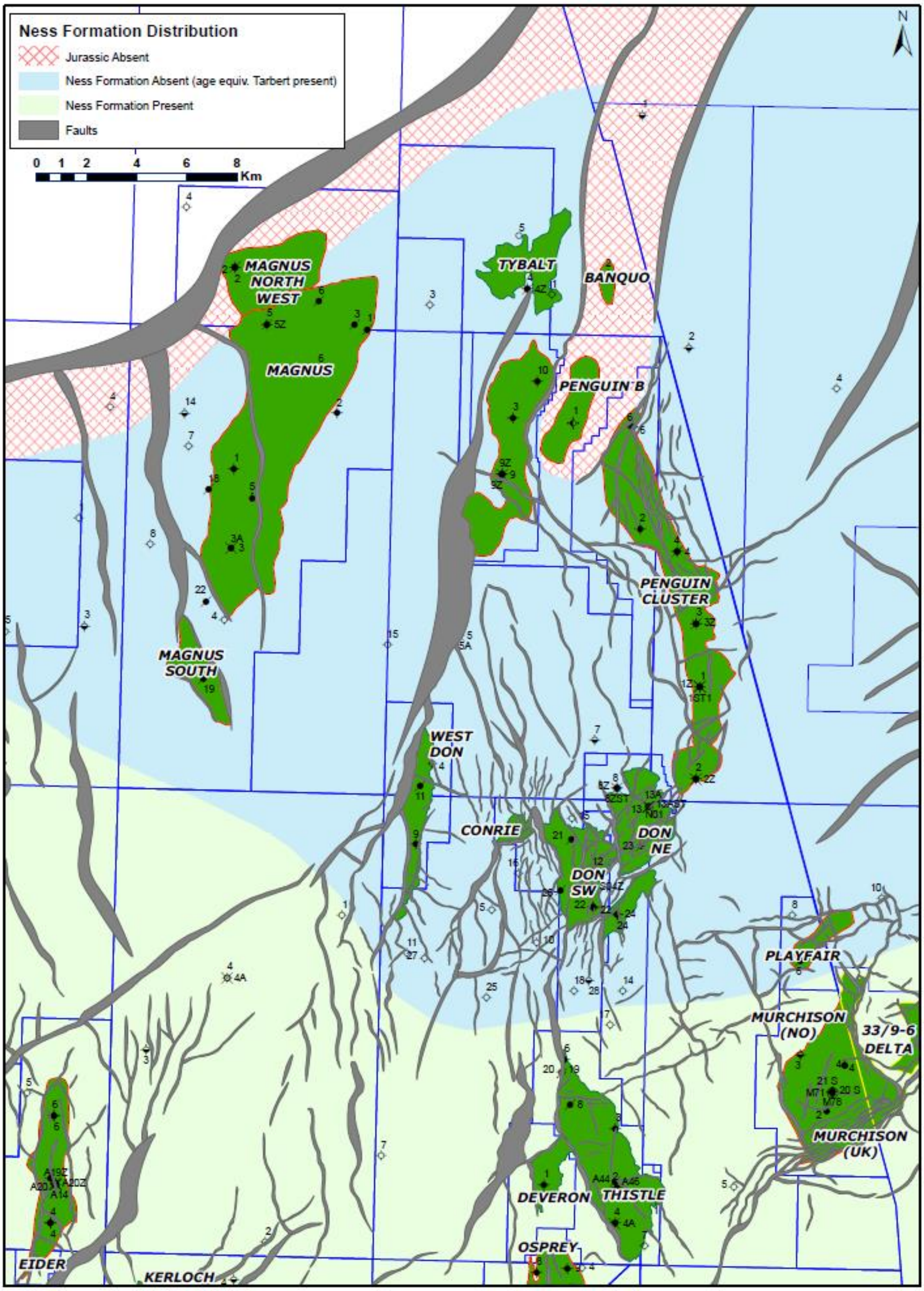

Figure 9: Greater Dons Area Ness Formation Distribution.

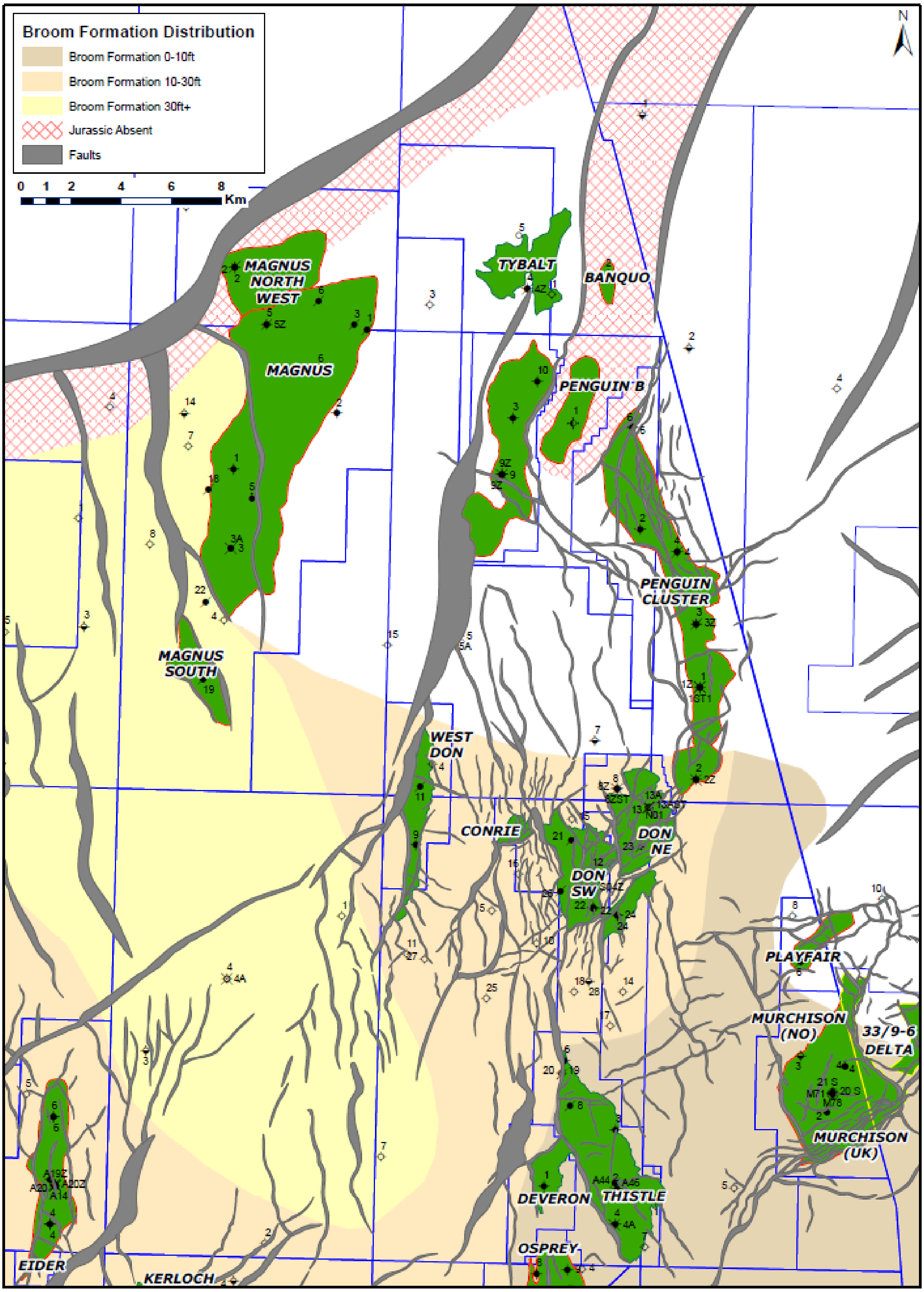

Figure 10: Greater Dons Area Broom Formation Distribution.

The Middle and Upper Jurassic sequence comprises the Heather and Kimmeridge Clay Formations, the latter of which in the Greater Dons includes three arenaceous members. Within the study area the Heather & Kimmeridge Clay Formation thicknesses are highly variable, reflecting their syn-rift sedimentation. Within the study area, where present, the Heather Formation varies in thickness from 28-1062 ftTVT and the Kimmeridge Clay Formation from 29-1640 ftTVT. The Heather Formation is comprised predominantly of shale with subordinate siltstones. Many studies have advocated the presence of Heather age sands in the study area which were supposedly redistributed due to erosion of Banks-Brent Group fault blocks, however no evidence has been found to support the presence of substantial or widespread Heather age sandstones within the study area. The Heather Formation was deposited in a deep marine environment and represents a continuation of the transgression which heralded the deposition of the Tarbert Formation. The Kimmeridge Clay Formation is comprised of organic rich shales which were deposited in a more restricted environment to the Heather Formation. The Kimmeridge Clay Formation within the study area also contains three important sandstone members; the Inter-Draupne Sandstone / Munin Member, the Ptarmigan Sandstone Member and the Magnus Sandstone Member. The Inter-Draupne Sandstone / Munin Member is found in the Norwegian sector east of the study area. These sands are related to erosion of the arenaceous Jurassic-Triassic sediments on the Snorre fault block which were then redistributed and deposited as shoreface and deep marine sands during the Upper Jurassic. The main portion of this sandstone fairway does not extend into the study area. The Ptarmigan and Magnus Sandstone Members record a series of submarine gravity flow fans, lobe or sheet systems. These sands were sourced from the north from erosion of the Magnus and Manet Ridges and the Margaretta spur. Successively younger submarine lobes reached further southwards and higher up on the basin bounding hanging wall and fault-scarp slopes. In proximity to the Penguin Half-Graben basin bounding faults the Ptarmigan / Magnus sandstone underwent slope failure resulting in soft sediment deformation, this is demonstrated in the Penguin A west wells. The Magnus and Ptarmigan Sandstone Members were deposited in a linked depositional system in which the Magnus Sandstone was deposited as a continuation of the Ptarmigan Sandstone depositional system.

Cretaceous

The Cromer Knoll Group comprises the deposits of the entire Early Cretaceous epoch. The Group was deposited under low energy marine conditions and within the study area typically comprises a basal limestone overlain by claystone interbedded with subordinate limestone. Significant thickness variations in the Group across the study area demonstrate that the Cromer Knoll was either syn-rift or that at the time of Cromer Knoll deposition there was significant topographic variations across the area which was inherited from faulting of the Jurassic (and older) stratigraphies. The Upper Cretaceous is comprised solely of the Shetland Group. This is a dominantly argillaceous unit and is comprised predominantly of claystones with minor amounts of limestone and sand / siltstone. The Shetland Group was deposited in an open marine environment and is considered the post rift thermal sag succession deposited after the active rifting of the North Sea ceased. Within the study area, where present, the Cromer Knoll Group varies in thickness from 18-1024 ftTVT while the Shetland Group varies in thickness from about 3000-6100 ftTVT.

Cenozoic

The Cenozoic Era comprises three stratigraphic units, the Rogaland, Hordaland and Nordland Groups. The Rogaland Group overlies the Upper Cretaceous Shetland Group and this sequence of rocks was deposited in a deep marine environment characterised by gravitational forces and submarine fans interbedded with hemipelagic sediments. Capping the Rogaland Group is the Balder Tuff, a seismically important, volcanically derived sediment deposited as a result of volcanism in the More Basin and Faeroe-Shetland region. During the Eocene further subsidence resulted in a major transgression, the deposits of this comprise the Hordaland Group. This Group predominantly comprises open marine shales and subordinate sands which were deposited along basin margins. Due to a regression at the end of the Eocene, sands were locally deposited due to erosion and re-deposition of sediments from local highs. From the Late Miocene, sedimentation was dominated by fine grained marine clastics, the Nordland Group. Local uplifts produced marginal marine sands. In general the period from Late Miocene to Recent is a regressive period. Sedimentation was affected by glacio-eustatic sea level changes. During the Quaternary, ice sheets advanced and retreated several times across the North Sea spreading a sheet of boulder clay, moraines and outwash sands across large areas of the North Sea Basin. Glaciomarine clays were deposited in front of the ice. Recent deposits in the area are generally the unconsolidated reworked deposits of the glaciogenic deposits they overlie. Within the Greater Dons Area the Cenozoic typically varies in thickness from 5100-6200 ft TVT.

5.2 Petroleum System

5.2.1 Source

There are several stratigraphic units in the area which could potentially contribute to hydrocarbon generation and expulsion, these include:

1. Banks Group Coals
2. Dunlin Group Shales
3. Brent Group Coals & Shales
4. Heather Formation Shales
5. Kimmeridge Clay Formation Shales

Of these the Kimmeridge Clay Formation is the most important source rock in the Northern North Sea. It has been confirmed as the main source rock for each of the hydrocarbon fields within the study area, including: Dons, Thistle, Osprey, Dunlin and Murchison. Hydrocarbon contribution from the Heather Formation has also been identified, particularly in relation to gas but some oil prone sections have also been recognised, PDF Ltd. (2008). The Dunlin Group in several wells in the Norwegian sector, to the east of the study area, has been identified as being oil and gas prone, however in most areas the Dunlin Group's contribution to hydrocarbon generation and expulsion is expected to be very limited. Hydrocarbon generation from the Banks & Brent Group is considered negligible.

Within the study area, at base Kimmeridge Clay level, most of the generative kitchens are in the main-early oil mature window, deeper sections of the study area reach the late oil-gas window. The top Kimmeridge Clay Formation also reaches the main to late part of the oil window, but over a much more restricted area. Upper Jurassic source rock intervals began early oil generation in the latest Cretaceous or Palaeogene, with a typical time lag of 5-15Ma between the onset of early oil for the base of the Heather Formation and the top of the Kimmeridge Clay Formation. Two phases of heightened burial are recognised on a typical geohistory plot for the area (Figure 11); Late Cretaceous-Mid Palaeogene and Pliocene-Recent, PDF Ltd (2008).

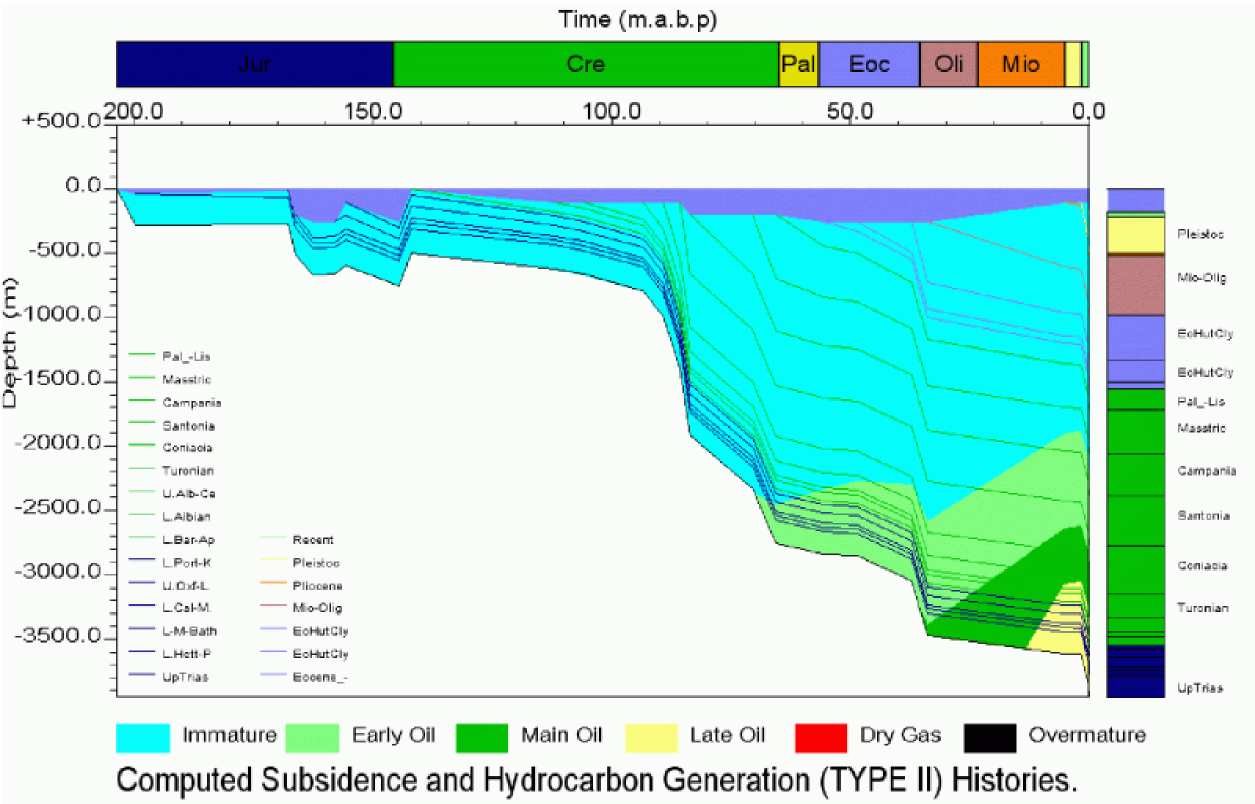

Figure 11: Geohistory Plot for 211/13-5A . (PDF 2008)

5.2.2 Migration

There are four separate generative source kitchens for the Greater Dons Area (Figure 12).The major regional kitchen in the area is the Marulk Basin, located in the Norwegian sector NE of the Dons Fields. Various basin modelling studies have confirmed this as the main kitchen for the Greater Dons Area. Several smaller kitchens are believed to be locally important. These include the Penguin Half-Graben, located west of the Penguins Cluster and east of the Magnus Field, the southern portion of block 211/13, east of the Penguins Cluster, and the Eider Trough, located to the east of the Eider Field in block 211/17. PDF Ltd. (2008) estimated volumes of hydrocarbon expulsion from these areas:

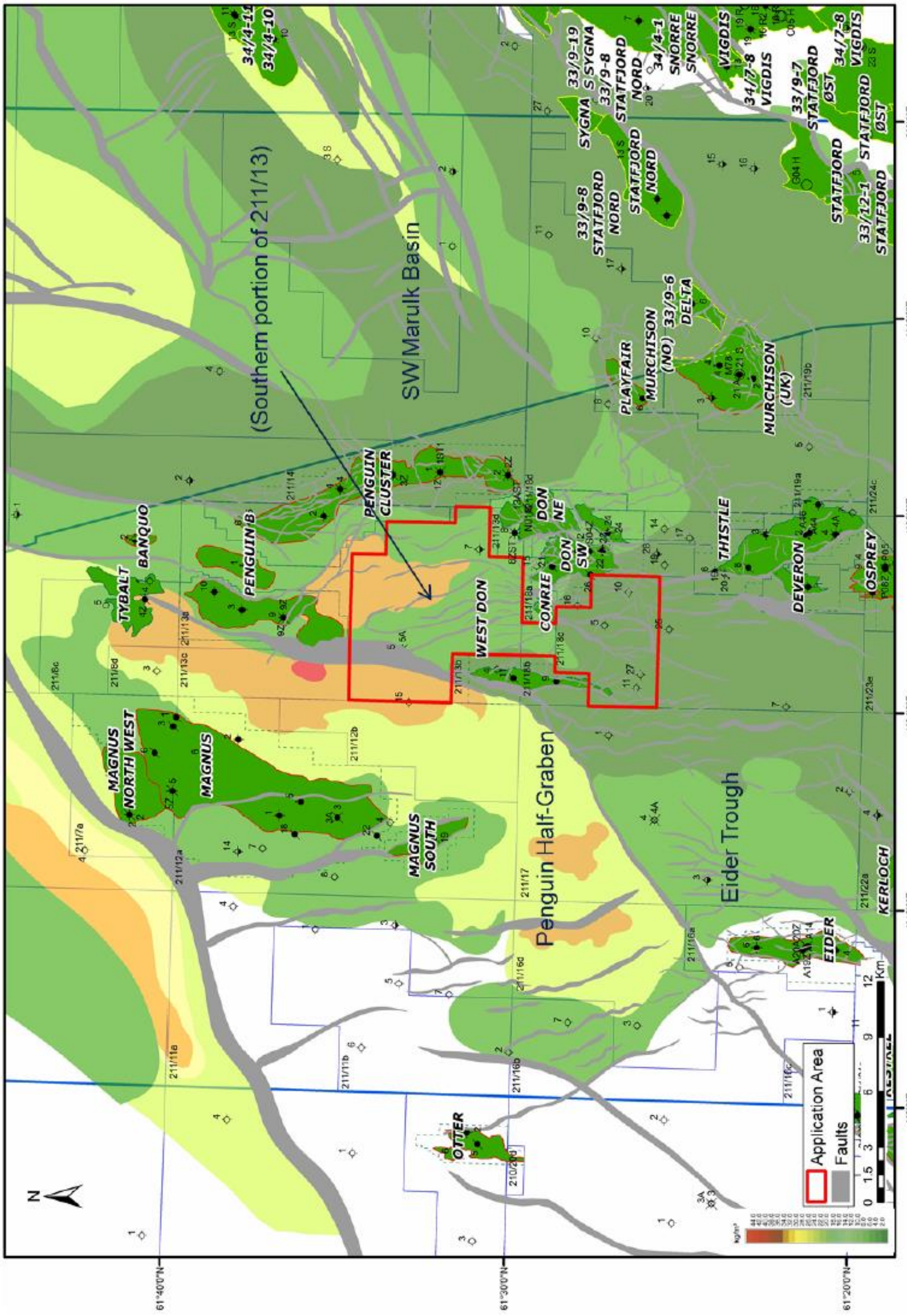

Figure 12: Expelled Oil from the Kimmeridge Clay at Present Day . Values expressed as kg/m3, high volumes red/orange.

1. The SW portion of the Marulk basin is estimated to have expelled 21.26 Billion bbls of hydrocarbons
2. The Penguin Half-Graben is estimated to have expelled 9.61 Billion bbls of hydrocarbons
3. The Southern portion of 211/13 is estimated to have expelled 1.43 Billion bbls of hydrocarbons
4. The Eider Trough is estimated to have expelled 1.11 Billion bbls of hydrocarbons

PDF Ltd. (2008) demonstrated hydrocarbon migration from each of these basins to the Greater Dons Area, (Figure 13). The Greater Dons Area is believed to have been filled via "fill and spill". Evidence for repeated secondary migration is provided by maturity markers, biomarkers, isotopes and ultimately gas oil ratios.

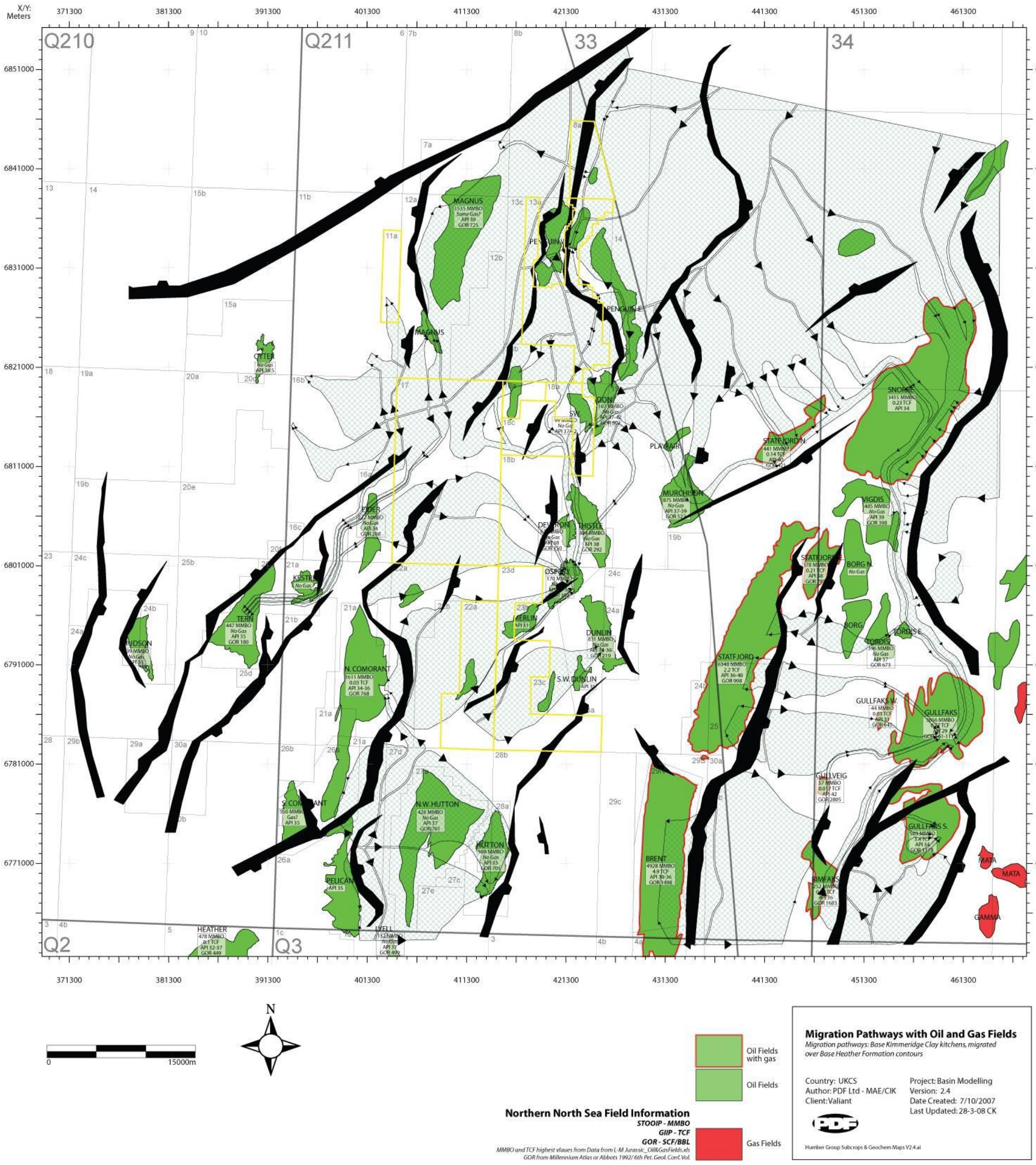

Figure 13: Regional Migration Pathways for Base Kimmeridge Clay . Migrated over base Heather Formation contours, (PDF, 2008).

5.3 Play Summary

5.3.1 Introduction

The study area is located in the regionally prolific Brent province and also the locally prolific Magnus province. In many studies the amount of attention given to the Brent Group and the Magnus Sandstone Member completely overshadows all other stratigraphic horizons and as such all-inclusive exploration does not always take place. At the onset of this study a fresh slate was used and exploration of all prospective horizons in the area was under-taken. The complete stratigraphy from basement to seabed was explored and considered, several plays have been identified, and these include:

1. The Cormorant Play
2. The Banks Play
3. The Brent Play
4. The Ptarmigan/Magnus Play

5.3.2 The Brent Play

As the operators of several Brent Group fields in the immediate area (West Don, Don SW, Conrie, Deveron & Thistle). An abundance of in-house knowledge exists, in EnQuest and Ithaca, about the Brent Group Play in the area.

Reservoir

The Brent Group was deposited regionally in the Northern North Sea. In the Greater Dons Area, areas in which the Brent Group is absent due to erosion or non-deposition are rare. These areas include the Penguin Horst & Magnus Ridge but it is also believed to be absent at the Western limit of Don SW field (see later discussion on the Kindle prospect). Several wells have not contained the Brent Group, originally explained due to faulting, and this is considered a local phenomenon. As such, with the exception of the Penguin Horst and the Magnus Ridge, the Brent Group had expected to be present across the entire study area. In the Dons area the only part of the Brent which significantly contributes to production is the Etive and Tarbert Formations. The Broom and Rannoch Formations are considered non-reservoir. This is in marked contrast to the Thistle Field in which the Rannoch Formation is a producing reservoir. Due to the absence of the Ness Formation (as discussed in the Regional & Tectonics section) the upper Brent Group exhibits high Net/Gross and is comprised predominantly of sand. Needless to say this greatly improves reservoir connectivity.

Diagenetic controls on reservoir quality are dominated by the influence of later shale-derived pore waters, circulating prior to oil emplacement. These include expelled acidic fluids associated with basinal decarboxylation / maturation reactions. The results include feldspar dissolution, kaolinite precipitation and quartz authigenesis. More deeply buried samples contain a higher percentage of illite and lower kaolinite, resulting from detrital smectite and kaolinite to illite conversion. In deeper reservoir sections arguably the most important diagenetic phase is diagenetic illite which destroys reservoir permeability. Regionally, studies have shown that temperature (and by proxy, depth) is the major controlling factor on illite formation. Several studies on the Brent Group show that illite becomes abundant in reservoirs between 11,000-11,500 ft TVDss, preliminary studies show that the Dons fields are closer to the latter end of that range. In any prospects or leads in which the Brent Group is buried to depths greater than 11,500 ft TVDss special circumstances are required for the reservoir to be of prospective quality, for example:

1. The emplacement of early oil which has been shown to retard illite formation
2. Chlorite overgrowths on quartz have been shown to retard quartz cement
3. Micro quartz cements have been shown to retard mechanical compaction
4. Acidic pore water dissolution of potassium feldspar

Seal

Top seal for the Brent Group is the Heather and Kimmeridge Clay Formations. It is conceivable that the Cromer Knoll also contributes to top seal, as it is a proven top seal for the Magnus Field (Ptarmigan & Magnus Sandstone reservoir). At a depth of greater than 10,500 ftTVDss, the Upper Jurassic is proven to retain a hydrocarbon column of 1000 ftTVDss in the underlying Middle Jurassic in Don SW. Lateral seal is provided in upthrown traps by the Heather Formation and Kimmeridge Clay Formation and downthrown traps by the Dunlin Group. The Dunlin Group is a proven lateral seal in the Brent Group in Don SW. Multiple contacts in Don NE suggest fault damage zones and shale smear also contribute to lateral seal.

Trap

Regional studies of this area of the Northern North Sea have demonstrated that fault traps are the dominant style in the Brent Group, both upthrown and downthrown traps.

Charge

In the Greater Dons area the major regional kitchen is the Marulk Basin, located in the Norwegian sector NE of the Dons Field, this is confirmed by various basin modelling. Several smaller kitchens are believed to be locally important. These include the Penguin Half-Graben, located west of the Penguins Cluster and east of the Magnus Field. The Eider Trough, located to the east of the Eider Field in block 211/17 and the deeper sections of block 211/13 (east of the Penguins Cluster). In the Dons area 'fill and spill' from one structure/accumulation to another has been recognised as an important filling mechanism, with structures in the NE being filled earliest before spilling progressively southwards. Evidence for repeated secondary migration is provided by maturity markers, biomarkers, isotopes and ultimately gas oil ratios.

5.3.3 The Banks Play

Reservoir

The Banks Group comprises the Statfjord and Nansen Formations. Within the Banks Group in the study area the Nansen Formation represents the most prospective reservoir unit. However, limited potential also exists within the underlying Statfjord Formation. In every sense the Banks Groups is more variable relative to the Brent Group. As referred to in an earlier section the Statfjord Formation is absent in the western portion of the study area. The Statfjord Formation is a lithologically diverse unit and in most sections will have a net/gross (sand) of less than 50%. In any development scenario it is expected that this moderate N/G system would be reflected in well performance, i.e. connectivity. The Nansen Formation is comprised predominantly of sandstone, therefore it's N/G (sand) is commonly higher than that of the Statfjord, locally it could be up to 90%. However the Nansen N/G (sand) is highly variable across the study area, see Figure 14. The highest quality Nansen Formation is found in the Dons / Penguin C,D,E(East) area, continuing east into the Norwegian sector. To the south, towards Thistle and Murchison the Nansen Formation thins considerably, similarly north of Penguin C / Penguin East. To the west (towards West Don, Penguin A / West and Magnus) the N/G (sand) of the Nansen Formation reduces considerably to a number more comparable to the Statfjord Formation. This is due to the replacement of the upper sandy section of the Nansen in the east with a shaly section in the upper Nansen Formation in the west. Diagenesis is critical to the Banks Group play. Many Banks Group sections are extensively carbonate cemented to the complete obliteration of reservoir quality. Ramm & Ryseth, (1996) noted a significant reduction in reservoir quality between 11,000-11,500 ft TVDss. The authors showed that this was related to the onset of extensive quartz and illite authigenesis. In any prospects or leads in which the Banks Group is buried to depths greater than 11,500 ft TVDss special circumstances are required for the reservoir to be of prospective quality, for example emplacement of early oil which has been shown to retard illite formation. It should be noted that 211/18a-24, just east of Don SW encountered a top Banks Group at 12,261 ft TVDss. In this well the Nansen Formation was tested at 1,660 BOPD on DST. This would imply that there are some mechanisms operating in the area which can preserve reservoir quality to depths at which reservoir quality should be destroyed, at least within the Banks Group.

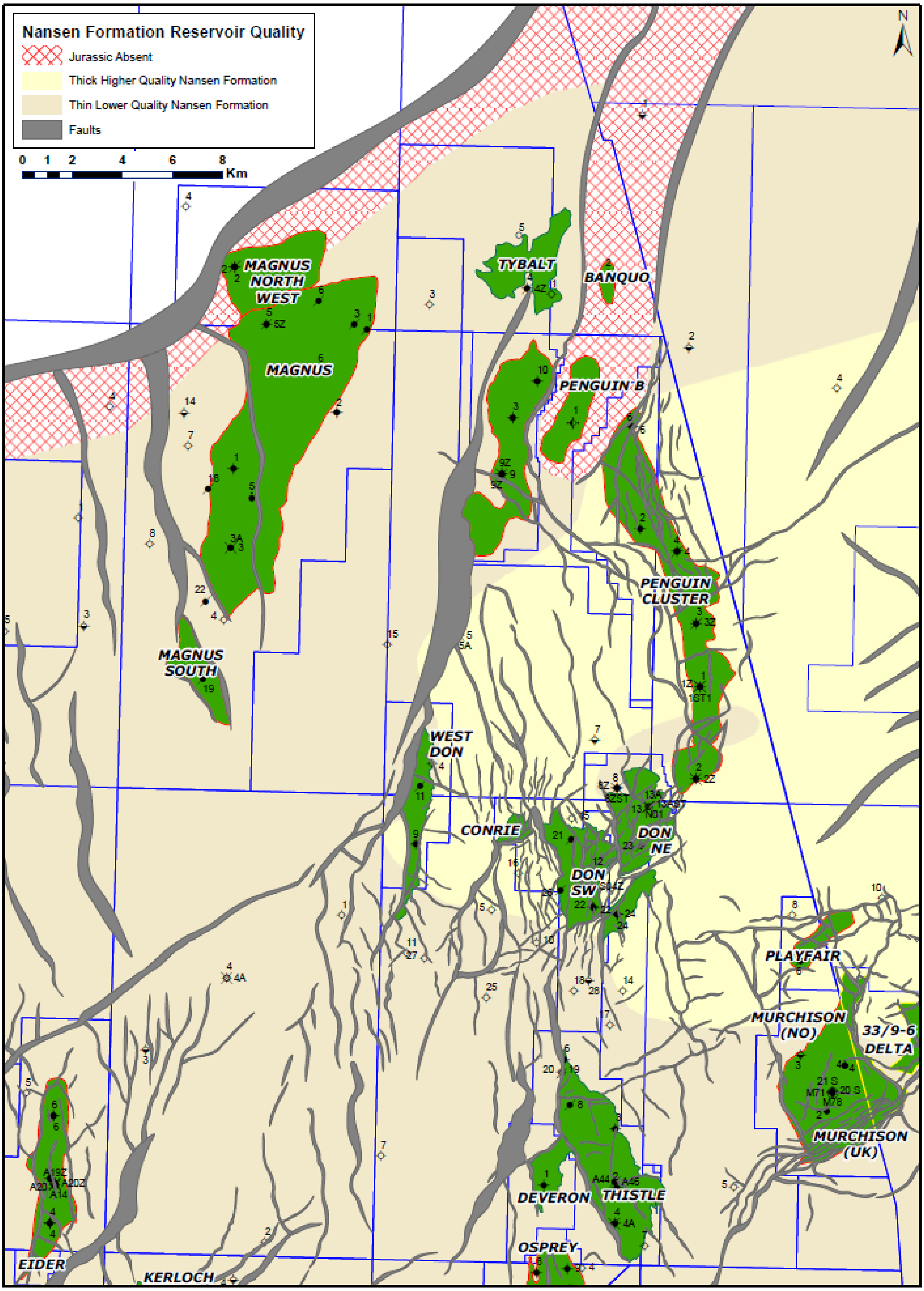

Figure 14: Greater Dons Area Nansen Formation Reservoir Quality Distribution.

Top seal for the Banks Group is the shale succession of the Dunlin Group. In the Dons fields, Banks Group hydrocarbon accumulations show a predominance for upthrown traps in which lateral seal would be provided by the Dunlin Group. Downthrown scenarios would juxtapose the Banks Group against the Banks Group or the Cormorant Formation, neither of which are expected to act as the ideal seal over geological time. In scenarios which downthrown traps are invoked shale smear/fault damage would be required.

Trap

Fault traps are believed to be the dominant style of trap in the Banks Group with upthrown traps being the only currently proven trap style.

Charge

In the Greater Dons area the major regional kitchen is the Marulk Basin, located in the Norwegian sector NE of the Dons Field, confirmed by various basin modelling. Several smaller kitchens are believed to be locally important. These include the Penguin Half-Graben, located west of the Penguins Cluster and east of the Magnus Field. The Eider Trough, located to the east of the Eider Field in block 211/17 and the deeper sections of block 211/13 (east of the Penguins Cluster). In the Dons area 'fill and spill' from one structure/accumulation to another has been recognised as an important filling mechanism, with structures in the NE being filled earliest before spilling progressively southwards. Evidence for repeated secondary migration is provided by maturity markers, biomarkers, isotopes and ultimately gas oil ratios.

5.3.4 The Ptarmigan / Magnus Play

Reservoir

Within the study area the extent of the Ptarmigan and Magnus Sandstone Members is limited and this distribution is outlined in Figure 15. The Ptarmigan Sandstone Member comprises relatively thin sand beds within the lower part of the Kimmeridge Clay Formation. Separating the Ptarmigan and Magnus Sandstone Members is Kimmeridge Clay shale which is followed by the thick blocky Magnus Sandstone Member. Net/Gross (sand) within the Ptarmigan Sandstone Member is highly variable though typically around 10-50%. The reason why it is so low is because it is comprised of relatively thin sandstone beds (up to 25ft) bedded within the lower Kimmeridge Clay shale. Additionally the Ptarmigan Sandstone Member is typically buried to greater depth relative to the Magnus Sandstone Member because it is deeper in the stratigraphy. Net/Gross (sand) within the Magnus Sandstone Member is usually much higher than that of the Ptarmigan Sandstone, it is commonly above 70% and frequently as high as 90%. It should be noted that the Net/Gross numbers quoted are for the main Ptarmigan and Magnus Sandstone depositional fairways. Outside of the main depositional fairway the gross unit thins and the net reduces proportionally. Initial petrophysical analysis indicates that the Ptarmigan & Magnus Sandstone Members can be of good quality to a depth of ~12,000 ft TVDss. Below 12,000 ft TVDss moderate reservoir quality can be expected, the depth at which poor-no reservoir quality would be prevalent has not yet been established.

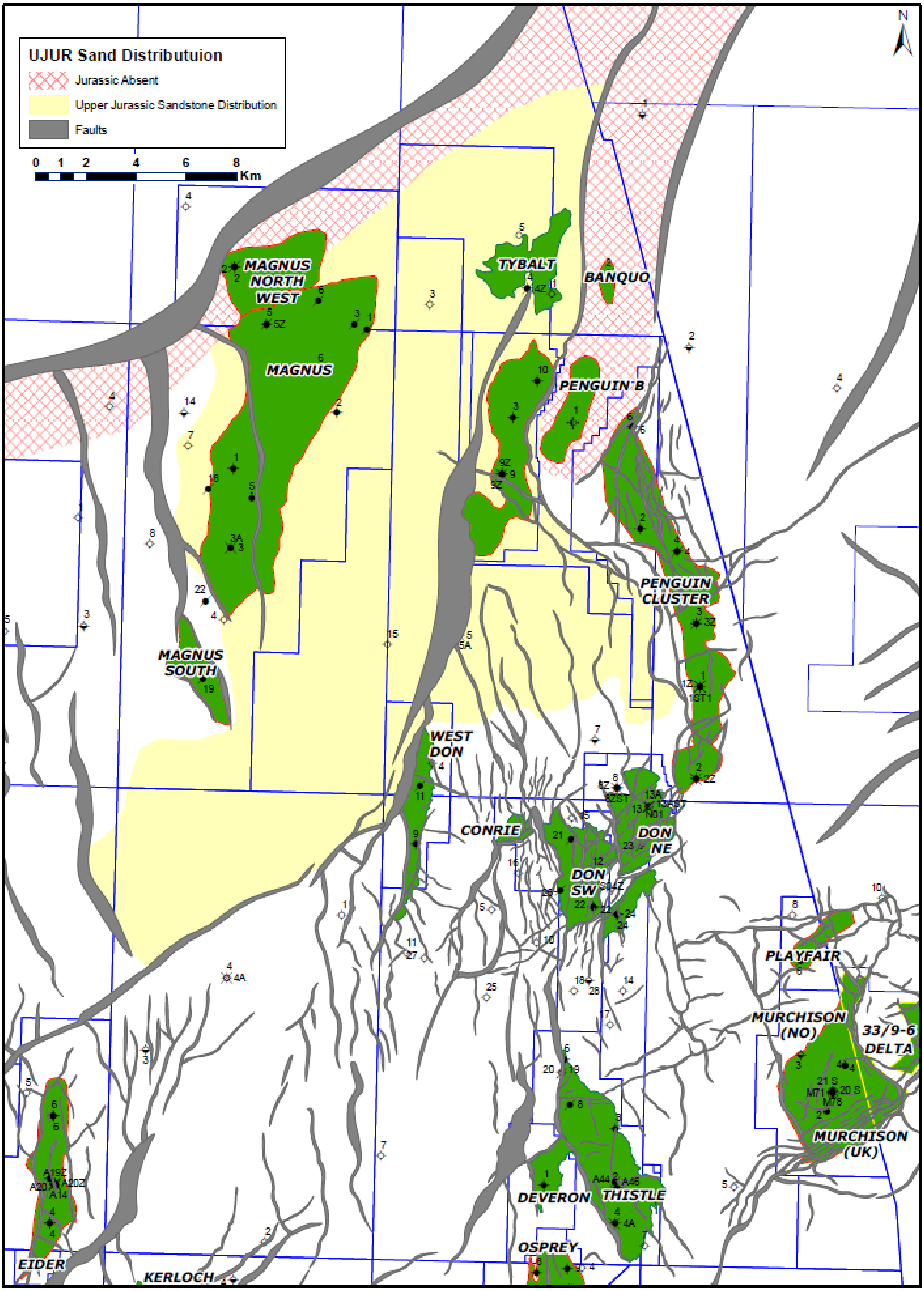

Figure 15: Upper Jurassic Sandstone Distribution within the Greater Dons Area.

Seal
The Ptarmigan and Magnus Sandstone Members are both "encased" within the regionally effective seal, the Kimmeridge Clay Formation. Lateral and vertical seal is provided by Kimmeridge Clay and Heather Formation shales. At the crest of the Magnus Field the upper Kimmeridge Clay Formation is eroded at the BCU so that the Magnus Sandstone Member directly subcrops the BCU. At this location the Cromer Knoll Formation directly overlies the Magnus Sandstone Member. The limestones and shales of the Cromer Knoll Group evidently act as an effective top seal here as it manages to hold back the entire oil column of the Magnus Field.

Trap
The trap for both the Magnus Field and the Penguin A / West in addition to the trap for the Tybalt discovery (in each of which the Ptarmigan & Magnus Sandstone Members is the reservoir) is a combination structural and stratigraphic trap. The Magnus Field is an upthrown tilted fault block in which the Ptarmigan/Magnus Sandstone Member is trapped by a combination of stratigraphic pinch out and erosional truncation of the reservoir at the crest of the fault block. Penguin A / West is a combination of stratigraphic pinchout and downfaulted lick up and this is comparable to the trapping style in the Tybalt discovery further north.

Charge
To the north east of the Magnus Field is the regionally important Marulk Basin, which is believed to be the source kitchen for the majority of oil fields in the area (e.g. Penguin, Dons, Thistle, Murchison & Statfjord Nord). More locally, within the Penguin Half-Graben, which lies directly to the east of the Magnus Field, Upper Jurassic source rocks are also hydrocarbon mature and are expected to have had a significant contribution to the charging of the Magnus Field.

5.3.5 The Cormorant Play

Reservoir
There are a limited number of wells which have penetrated the Cormorant Formation within the study area. Of these wells the overwhelming majority penetrated only a thin section of uppermost Cormorant Formation. Very few wells penetrated the deeper section and fewer still, the base of the Cormorant. Of the wells which did penetrate the Cormorant every one penetrated a sand bearing section. Sand presence is not an issue with the Cormorant Formation but the major issue is reservoir quality. The Cormorant Formation deposits are first cycle siliciclastics, therefore they are typically compositionally immature. This means that a great abundance and variety of material is available for the formation of diagenetic mineral phases. Compounding this is the presence of both eogenetic and mesogenetic carbonates which have in many places occluded porosity and permeability. Within the study area this has resulted in a major reduction of reservoir quality, to the extent that net/gross is typically less than 40% and commonly as low as 5%. It should be noted that within the study area net/gross pay is always significantly less than net/gross reservoir. This extreme low net/gross system is expected to have a major impact on reservoir connectivity and therefore well production performance. It should be noted that locally within the northern North Sea net/gross within the upper Cormorant Formation can reach as high as 80%, such as in the Beryl, Nevis and Snorre Fields, however this level of reservoir quality is not expected within the study area.

Seal
The only proven seal within the study area is the Shetland Group shales, where they directly overlie the Triassic where it subcrops the BCU on the Penguin Ridge. Regionally Rhaetian / Hettangian claystones / mudstones of the Uppermost Cormorant Formation or lowermost Banks Group have been noted to act as effective seals for hydrocarbon accumulations within the Cormorant Formation.

Trap
Within the study area there are only two known hydrocarbon accumulations within the Cormorant Formation. These are the Banquo and Helena / Penguin B discoveries. Both of these discoveries comprise the same trap style. Banquo and Helena / Penguin B are located on the Penguin Horst/Ridge, a structurally elevated Triassic horst block which runs NE-SW through blocks 211/8 and 211/13. This horst block dips to the SE and is bound to the NW by a major normal fault. Along this horst the Upper Cretaceous Shetland Group rests unconformably upon the Triassic Cormorant Formation. Therefore the proven trap in the Cormorant Play is an upthrown tilted fault block.

Charge
In the Greater Dons area the major regional kitchen is the Marulk Basin, located in the Norwegian sector to the east and NE. Various basin modelling studies have confirmed that the main hydrocarbon input to the Greater Dons Area originates from the Marulk Basin. Several smaller kitchens are believed to be locally important. These include the Penguin Half-Graben, located west of the Penguins Cluster and east of the Magnus Field. The Eider Trough, located to the east of the Eider Field in block 211/17 and the deeper sections of block 211/13 (east of the Penguins Cluster).

6 Prospectivity Update

This is a mature and established area of the Northern North Sea and a significant amount of previous work has been performed on the area. As part of the original licence application, EnQuest evaluated the prospectivity within blocks 211/13c and 211/18c and five leads/prospects had been identified, tabled in Table 4: Previously identified prospectivity and shown on a map in Figure 16.

Lead Name	Age	Description
Mossat	Brent and Banks	4 way dip closed structure – poorly imaged on existing seismic. Brent deeper than 11500ft TVDSS.
Kindle	Brent	Stratigraphic trap, up dip and to the west of the DonSW (Area 22), assuming continuity of the Brent system.
Caliban Central	Brent	Structural/Stratigraphic trap requiring fault seal against the Halibut High.
Carvie	Ptarmigan & Magnus	Stratigraphic Trap requiring Magnus sand pinch out North of the West Don field and on the West Don Terrace.
Caliban North	Brent	A small Structural/Stratigraphic trap requiring fault seal against the Halibut High.

Table 4: Previously identified prospectivity

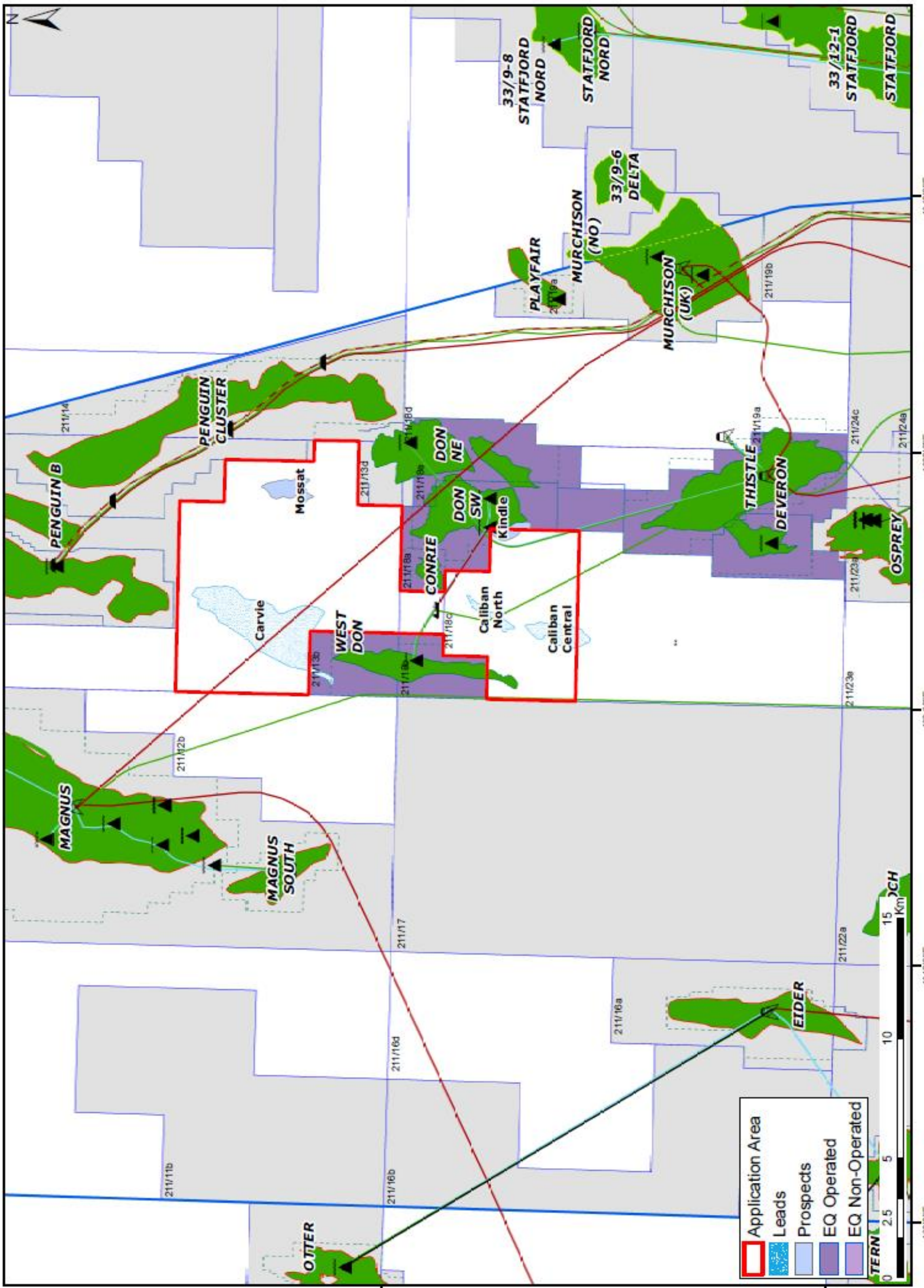

Figure 16: Previously identified prospectivity

6.1 Mossat

Introduction

Mossat had been evaluated at the time of licence application on poor quality seismic data. The lead is located in the eastern portion of block 211/13c, north of Don NE and west of Penguin East. It is a 4 way dip closed structure at both Brent and Banks units. A map of Top Brent Depth structure is shown in Figure 17, showing that the top of the Brent at approximately 11700ft TVDSS on the crest of the Mossat structure.

Reprocessing of the Western Geco seismic data was performed for the mapping of the Dons field but the Northern edge covered the southern portion of the Mossat lead. As a much larger area was input into the final migration, there is no migration apertures to consider on the licenced data and mapping can legitimately made on to the southern part of the Mossat structure. An example of the uplift from reprocessing is shown comparing Figure 18 and Figure 19.

The new data shows a slightly more complexly faulted structure than was evident on the previous WGC data and, consequently a smaller connected structural Horst, although the structural high clearly remains.

Historically Shell and Valiant Petroleum (now Ithaca) have both, independently, identified a prospect in the Mossat area. The primary reservoir in the Mossat prospect is the Brent Group while the secondary reservoir is the Banks Group.

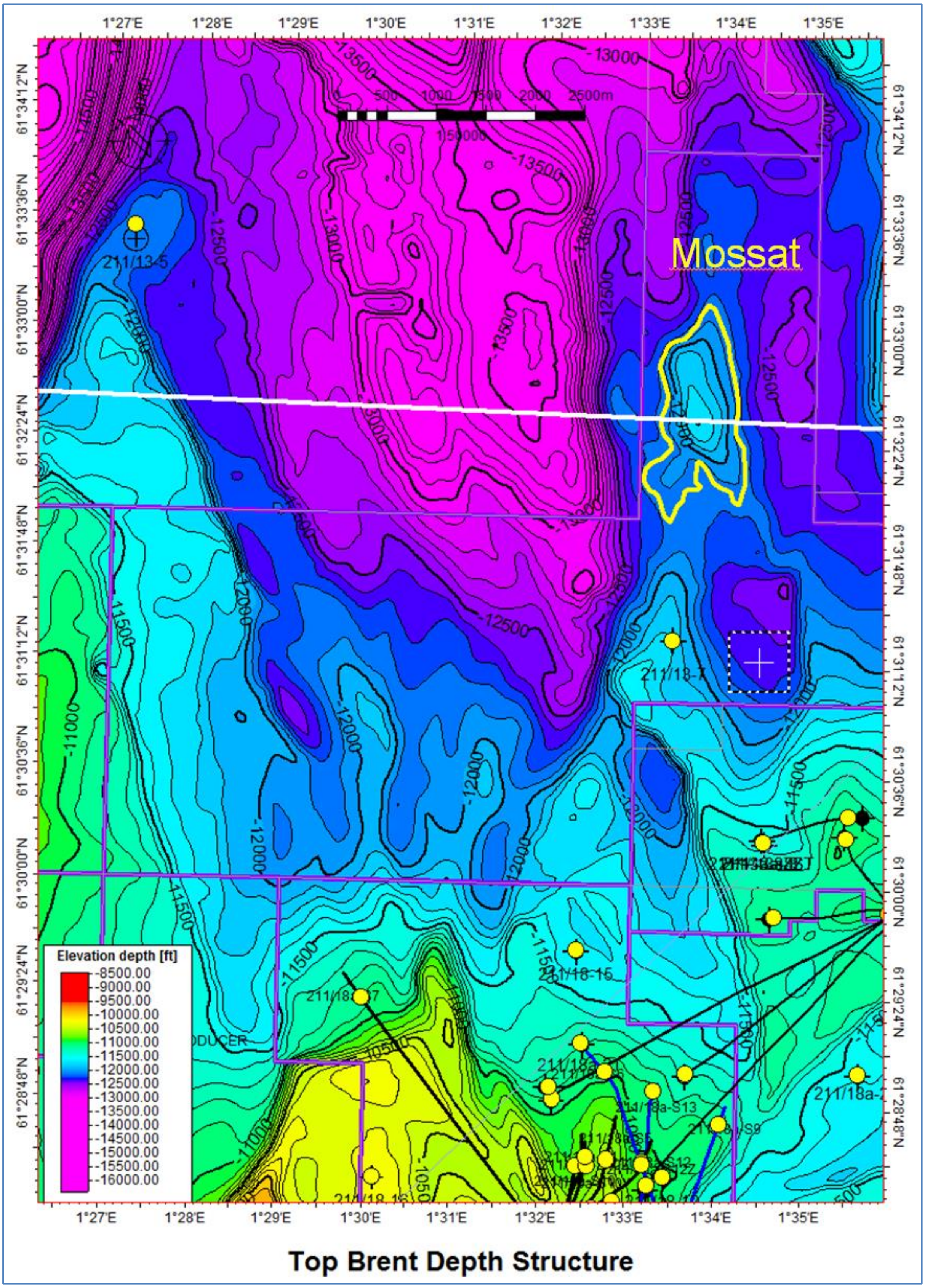

Figure 17: Mossat Prospect Top Brent Group Map with location of W-E Seismic Traverse

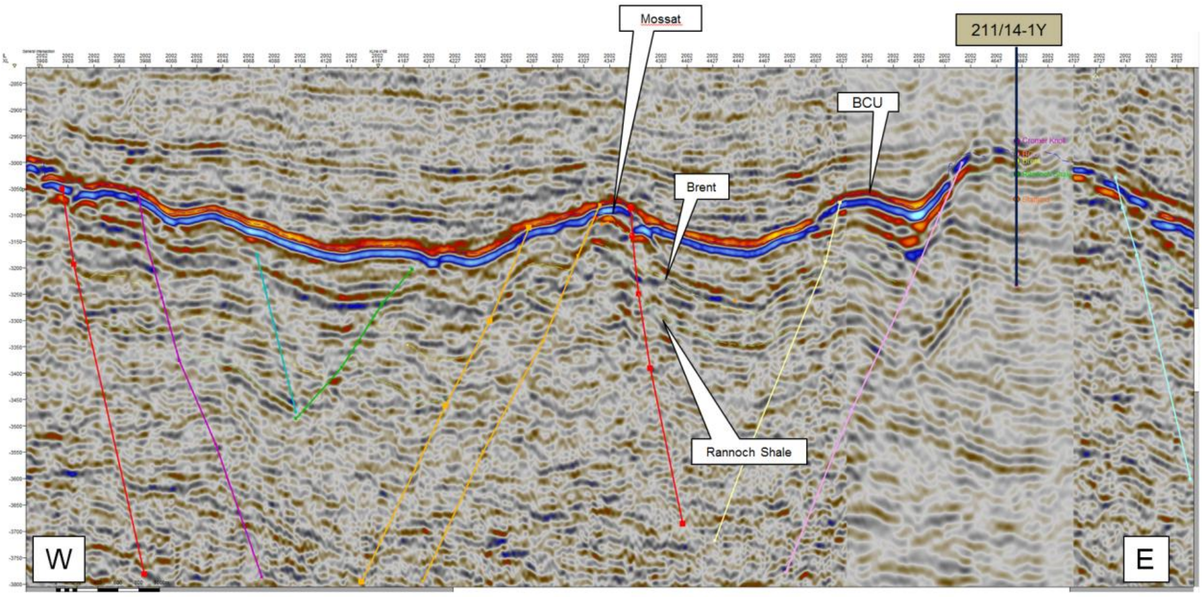

Figure 18: Mossat W-E Seismic Line on Original Seismic.

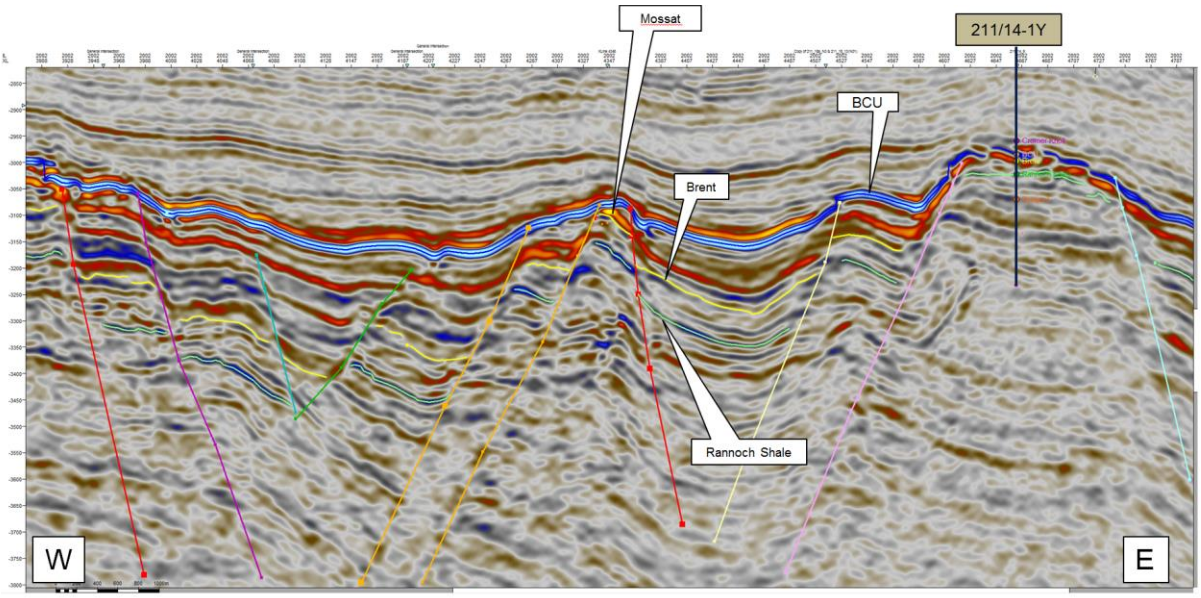

Figure 19: Mossat W-E Seismic Line from WGC PSDM (2015).

Reservoir

The Brent Group: Due to the position of the Mossat prospect in relation to the Brent depositional fairway both the Broom and Ness Formations are absent. Additionally the Etive Formation is expected to be thin. Correspondingly the Rannoch and Tarbert Formations are expected to be relatively thick. Due to the depth of the Brent Group over the Mossat prospect, around 11,800ftTVDss, special circumstances are required to have preserved or enhanced reservoir quality, such as early oil emplacement. Due to the proximity of the Mossat prospect to the kitchen "southern portion of 211/13" it is conceivable that Mossat received an early oil charge.

The Banks Group: Due to the position of the Mossat prospect in relation to the Banks Group depositional fairway both the Statfjord and Nansen Formations are expected to the present. The Nansen Formation is considered the only prospective part of the Banks Group and due to its position along the depositional fairway is expected to be thick, in the order 100+ftTVT and of high net/gross (sand) quality. Comparable to the Brent Group, owing to the great depth of the Mossat prospect Banks Group special circumstances are required for the Banks Group to be prospective.

Seal

For the Mossat prospect at Brent level the top and lateral seal is the Humber Group. At the Banks level the seal is provided by the Dunlin Group. Also, both Brent and Banks Group reservoirs could have their primary stratigraphic seals supplemented by fault seal.

Trap

Mossat is a faulted 4 way dip closed structure which, although clearly elevated above its flanks is difficult to properly evaluate due to poor quality seismic data over the entirety of the prospect.

Charge

The Mossat Prospect is located within a generating source kitchen, the "southern portion of 211/13". The source rock in this area is expected to be in the main-late oil window. Basin modelling studies by PDF (2008) predicted that this kitchen expelled 1.43 Billion bbls of hydrocarbons over a period from the Late Cretaceous-Recent.

Updated Summary of Prospect

The Mossat prospect is structurally deep, even at the Brent (>11500ft limit beyond which special circumstances are required to preserve porosity), with correspondingly increased risk of encountering poor reservoir quality (negatively impacting porosity, permeability, oil saturation and recovery factor). With the improved seismic data quality, there is more evidence of compartmentalisation and the Horst appears slightly smaller areally than mapped previously. Connected volumes are likely to be smaller than as mapped for the licence application. Volumes were not updated as the whole structure could not be remapped on the reprocessed data.

Given the current and forecast oil prices, this prospect is deemed too small and too high risk to be economic.

Brent Group Prospect

Variable	P90	P50	P10	Distribution
GRV MMm³	21	48.1	110	Lognormal
Net-to-gross (%)	45	58.1	75	Lognormal
Porosity (%)	14.5	15.75	17	Lognormal
So (%)	50	60	70	Lognormal
FVF (vol/vol)	1.25	1.36	1.4	Lognormal
Recovery factor (%)	5	12.5	20	Lognormal

Table 5: Mossat Brent Group MMRA Input Parameters

	STOIIP (MMbbls)	Resources (MMbbls)
PMean	16.49	2.25
P90	5.83	0.63
P50	12.73	1.62
P10	32.09	4.6

Table 6: Mossat Brent Group STOIIP & Resources

Component	Chance (%)
Reservoir	75
Seal	90
Trap	90
Charge	100
Pg	61

EnQuest define the geological probability of success (Pg), as the probability of getting onto the predicted range defined by the P90-P10.

Table 7: Mossat Brent Group Risk

Banks Group Prospect

Variable	P90	P50	P10	Distribution
GRV MMm³	16.8	30.8	56.4	Lognormal
Net-to-gross (%)	25	40.3	65	Lognormal
Porosity (%)	13	14.2	15.5	Lognormal
So (%)	58	63.7	70	Lognormal
FVF (vol/vol)	1.1	1.241	1.4	Lognormal
Recovery factor (%)	10	14.5	21	Lognormal

Table 8: Mossat Banks Group MMRA Input Parameters

	STOIIP (MMbbls)	Resources (MMbbls)
PMean	6.73	1.03
P90	2.59	0.35
P50	5.52	0.8
P10	12.42	1.98

Table 9: Mossat Banks Group STOIIP & Resources

Component	Chance (%)
Reservoir	50
Seal	90
Trap	90
Charge	100
Pg	40.5

EnQuest define the geological probability of success (Pg), as the probability of getting onto the predicted range defined by the P90-P10.

Table 10: Mossat Banks Group Risk

6.2 Kindle

Introduction
Kindle is a higher risk prospect and had not been fully evaluated at the time off application. The reprocessed WGC PSDM adequately covered the Kindle prospect, allowing an updated view of this lead (Figure 20). It is located in the eastern portion of 211/18c, directly west of Don SW (Figure 21). It is a potential westerly extension of the SW Don field between the oil filled Area 22 and the up dip but wet wells of the Halibut High. The Kindle prospect reservoir is the Brent Group, as the Banks Group is expected to be very high risk at this location due to concern of a lack of lateral fault seal. Given the complexity of the geology observed from nearby well data, the evaluation of this prospect was expected to benefit from better seismic data quality which would allow a more reliable evaluation of the potential volumes and risk.

Figure 20 shows a SW-NE seismic line just south of the Kindle prospect. This clearly demonstrates that the interval between BCU and Statfjord thins to the west towards the Kindle prospect. This results in the absence of the Brent interval, either by non-deposition or erosion (although the latter is deemed more likely as the Brent is present but eroded to the west in the 211/18-10 well). This thinning interval is observed to the south on seismic but with difficulty to the north due to the complex geology. To the north, however, a similarly absent Brent interval would explain the well results at 211/18-5, 5Z, S8, S10 and 26, which all encountered thinned or absent Brent. It can, therefore be assumed that the mechanism that resulted in absent Brent is also at work in the intervening block, known as Area 22. The Kindle prospect would sit up dip and further to the west than Area 22 and, therefore, the chance of success for reservoir presence has been substantially reduced.

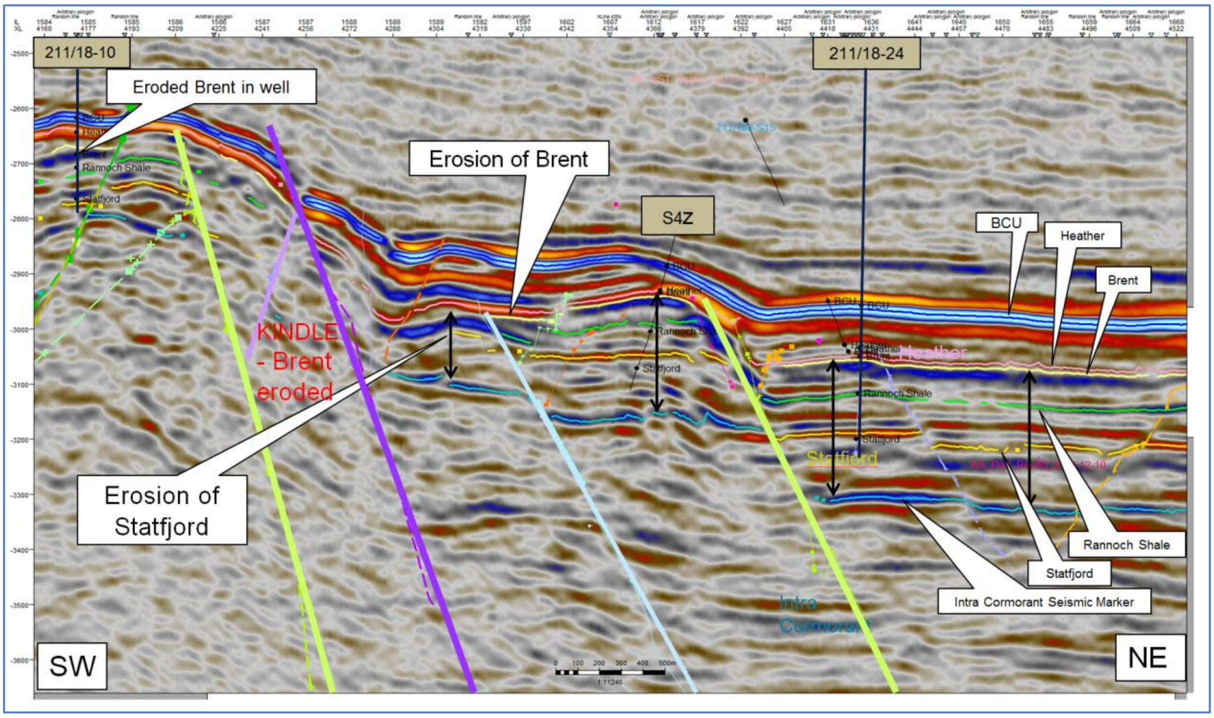

Figure 20: Kindle SW-NE Seismic Line.

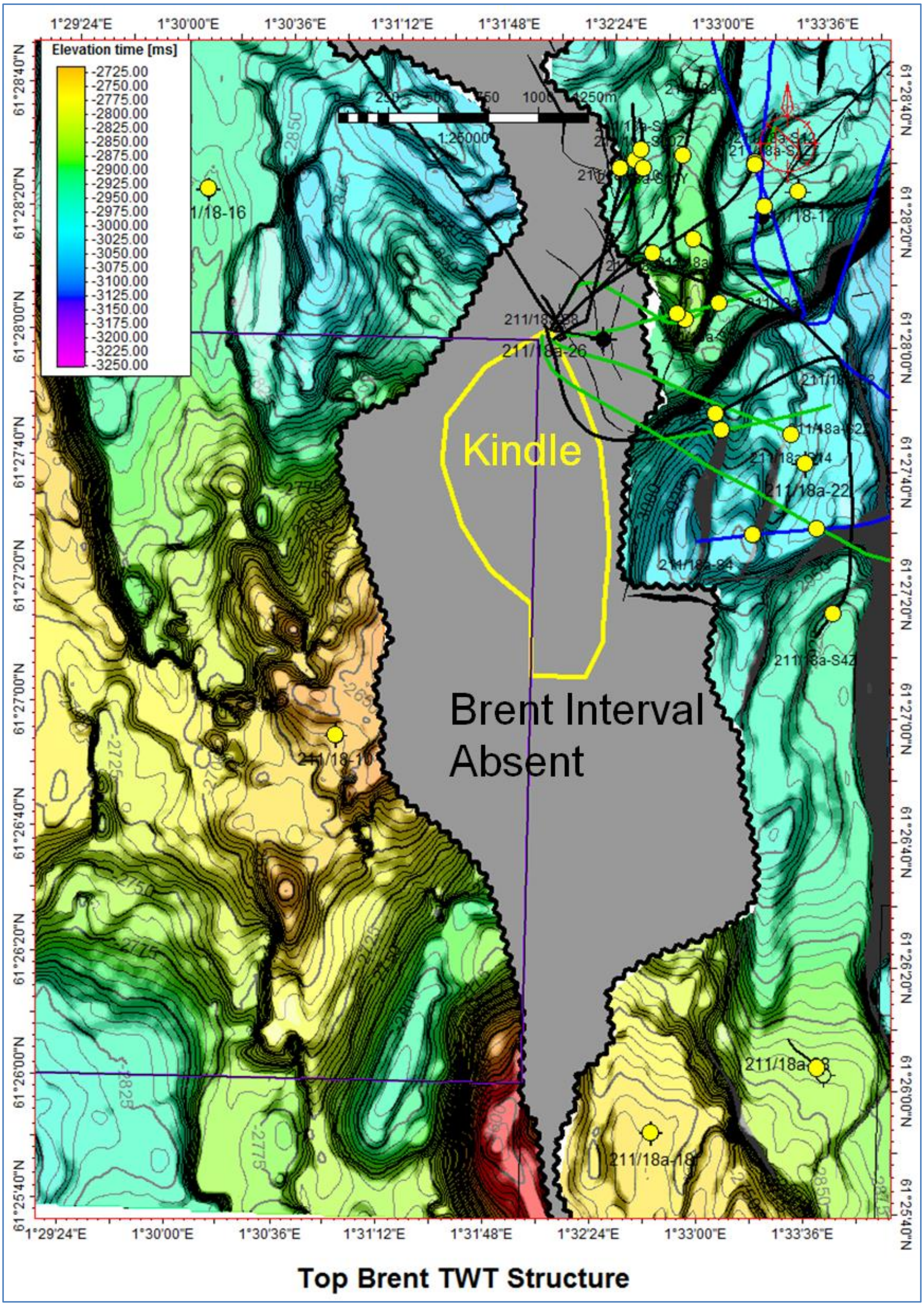

Figure 21: Kindle Prospect Map

Reservoir

Due to the position of the Kindle prospect in relation to the Brent depositional fairway the Ness Formation is expected to be absent. Additionally the Broom Formation is expected to be thin. Correspondingly the Rannoch, Etive and Tarbert Formations are expected to be relatively thick. The latter two are expected to be the main reservoir. Due to the interpreted depth of the Brent Group over the Kindle prospect, around 10,300 ftTVDss, the Brent reservoir is expected to be of good quality. Over the Halibut High, directly to the west of the Kindle prospect, the Brent Group is partially eroded and it is conceivable that the Brent within the Kindle prospect is also eroded or partially eroded. This possible erosion is reflected in the reservoir risking parameter.

Seal

Top seal for the Kindle prospect Brent reservoir is the Humber Group. Lateral seal relies upon a sealing fault in which the seal would be provided by shale smear or cataclasis along the fault plane or juxtaposition of the Brent reservoir interval against Dunlin shales.

Trap

Kindle is a rotated fault block up dip from the SW Don field Area 22. Within the fault block, the stratigraphy is uncertain but the Brent Group can be interpreted to be present from seismic data, although recent well data (S26 et al) demonstrates that the seismic data can be misleading and that this area is particularly structurally complex with multiple episodes of faulting before and after Brent deposition.

Charge

The Kindle prospect is located directly east of the oil filled Don SW field. North East of the Kindle prospect is the regionally important hydrocarbon kitchen, the Marulk Basin. Basin modelling studies have indicated hydrocarbon charge from this kitchen into the Dons and more specifically the Kindle prospect area. PDF (2008) predicted that the southern portion of this kitchen expelled 21.26 Billion bbls of hydrocarbons over a period from the Late Cretaceous-Recent. Despite all of this, the Halibut High, the large fault block to the west of Don SW & NE and indeed west of the Kindle prospect is dry, evidenced by all three wells drilled on it (211/18-5, 211-18-10, 211/18-16). There are several possibilities as to why this major fault block is dry, these include top seal failure and also lack of charge due to fault shadowing. Because of the proximity of this dry fault block to the Kindle prospect the risking of the charge parameter has been incorporated in the seal and trap components.

Updated Summary of Prospect

In spite of its proximity to the Don SW infrastructure, <u>this prospect is now deemed uneconomic due to this substantially increased risk of reservoir presence.</u>

Variable	P90	P50	P10	Distribution
GRV MMm^3	32.2	64.9	130.9	Lognormal
Net-to-gross (%)	60	73.5	90	Lognormal
Porosity (%)	14	15.9	18	Lognormal
So (%)	60	69.3	80	Lognormal
FVF (vol/vol)	1.2	1.208	1.216	Lognormal
Recovery factor (%)	23	29.2	37	Lognormal

Table 11: Kindle MMRA Input Parameters

	STOIIP (MMbbls)	Resources (MMbbls)
PMean	32.05	9.5
P90	13.01	3.68
P50	26.54	7.7
P10	57.84	17.54

Table 12: Kindle STOIIP & Resources

Component	Chance (%)
Reservoir	**10**
Seal	50
Trap	70
Charge	100
Pg	4

EnQuest define the geological probability of success (Pg), as the probability of getting onto the predicted range defined by the P90-P10

Table 13: Kindle Risk

6.3 Other Identified Leads

Several leads are identified within the application area and span a variety of play types including Banks, Brent and Ptarmigan / Magnus Plays.

Due to the minor risked mean recoverable resources expected from these prospects they were considered marginal at the time of application. Within the North Sea the size of commercial prospects/discoveries is becoming ever smaller, the nature of these nearfield leads meant that they may have become significant in a future economic regime. However, given the drop in oil price, these have become even less economic. All leads were interpreted (where possible) on the reprocessed WGC PSDM seismic.

Caliban Central

Caliban Central is a lead in block 211/18c. An updated map is shown in Figure 22. This lead comprises a Brent Group reservoir in a downthrown trap sealed by the Humber Group and with lateral seal against the Dunlin Group. The depth of burial of the Brent reservoir in this lead would suggest that the Brent Group is likely to be of good quality. Up dip of the Caliban Central prospect is the aforementioned dry Halibut High. Due to the proximity of this lead to the Halibut High and the potential to be in a migration shadow, the risking of the charge parameter is high. Reinterpretation of this lead on the WGC PSDM showed a more complexly faulted area than had been previously interpreted. This complexity, although perhaps creating more ways to trap any migrating hydrocarbons would also reduce the size of individual compartments, reducing reserves and increasing costs to exploit, should a hydrocarbon column be established. Additionally, the fault separating Caliban Central from the wet 211/18b-25 seems small in comparison to other faults within the Caliban Central complex. Volumes have not been adjusted but risks have increased making this clearly unattractive commercially.

A W-E seismic line showing the Caliban Central lead is shown in in Figure 23.

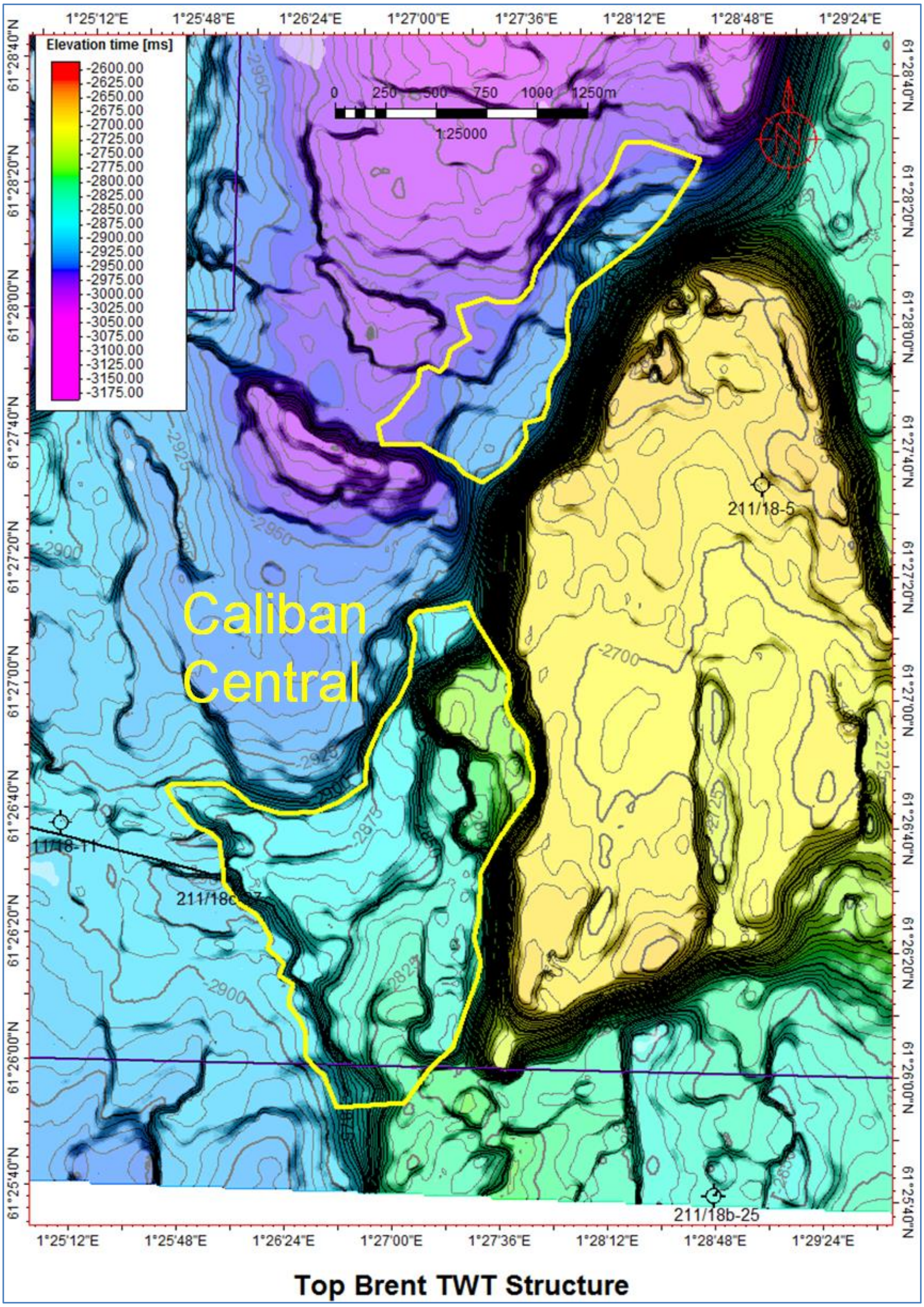

Figure 22: Caliban Central Top Brent Map.

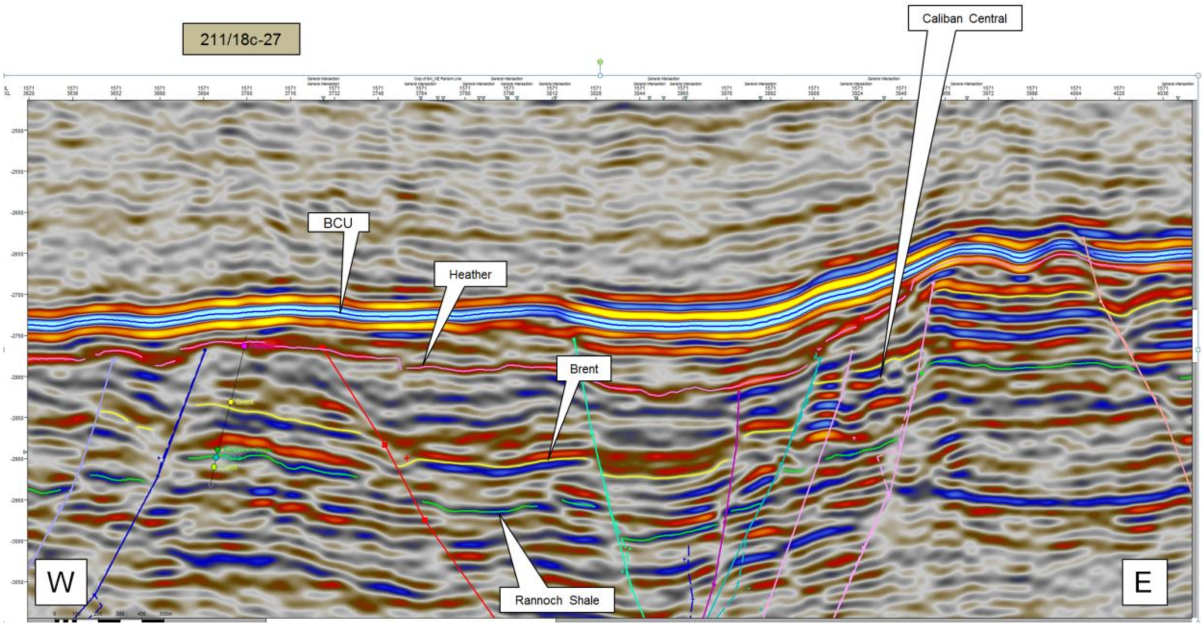

Figure 23: Caliban Central W-E Seismic Line

Carvie

Carvie is a lead in block 211/13c and is shown in Figure 24. Figure 25 & Figure 26 show seismic traverses across the lead. The lead comprises a Ptarmigan & Magnus Sandstone Member reservoir in a mixed structural/stratigraphic trap. The seal for this lead is the Humber Group, in which the reservoir is "encased". The Carvie lead is positioned relatively distally on the Ptarmigan/Magnus Sandstone depositional fairway as demonstrated by the 211/13-5a well which showed the presence of a very thin sand but with preserved hydrocarbons, proving a working trap. As a result of the well results, the thickness and quality of net sand in the Carvie area is likely to be limited and, hence, the main risk on this lead is reservoir presence and quality.

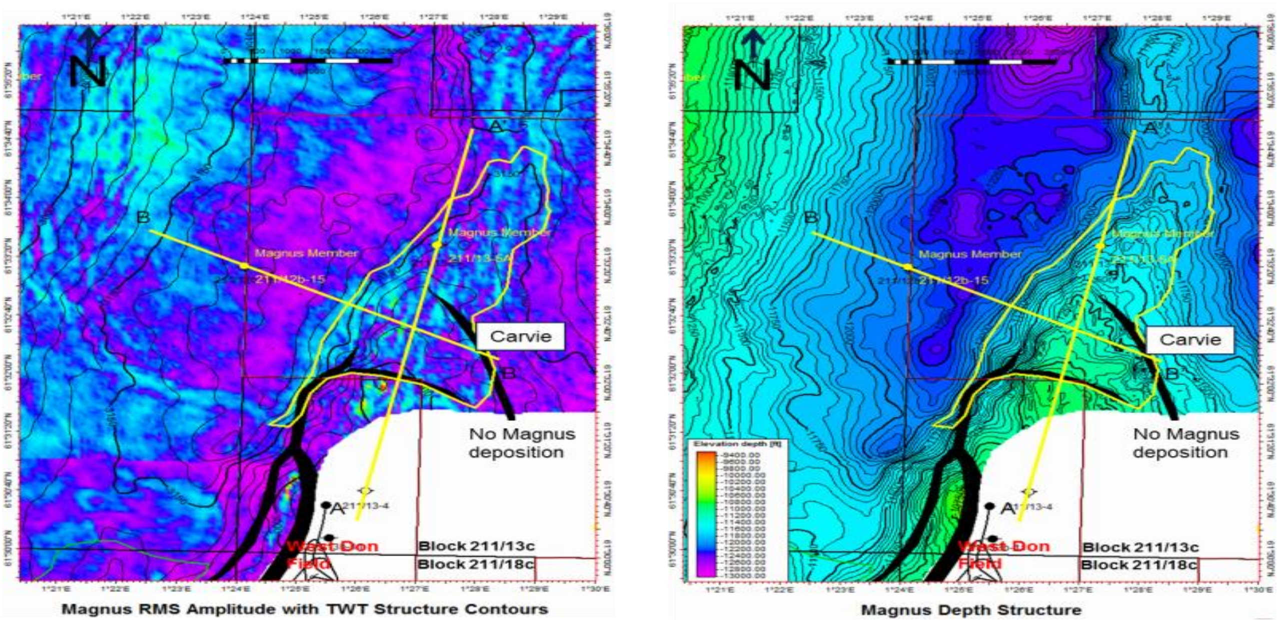

Figure 24: Carvie Top Magnus Maps

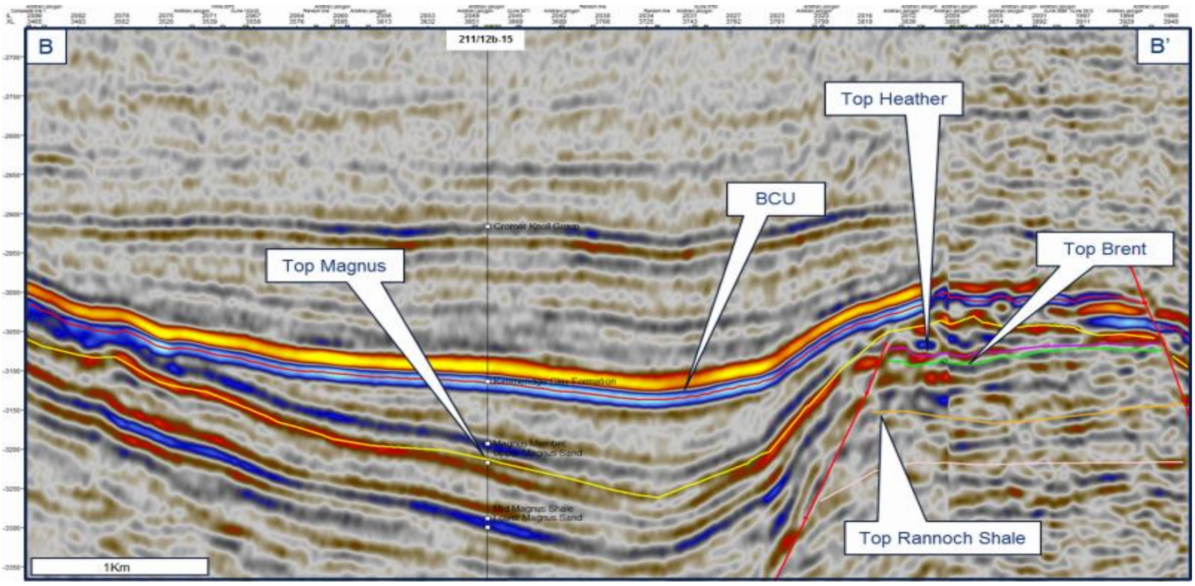

Figure 25: Carvie Cross Section E-W

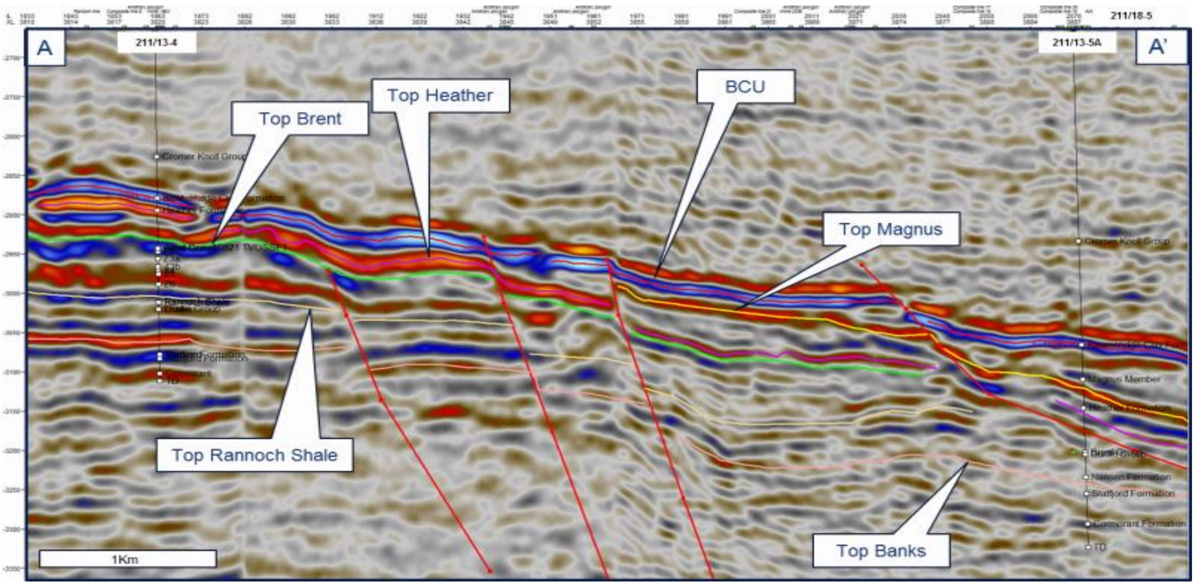

Figure 26: Carvie Cross Section N-S

Caliban North

Caliban North is a small lead in block 211/18c. Top Brent TWT Structure map outlining the lead is shown in Figure 27. A W-E seismic line on the WGC reprocessed data through the lead is shown in Figure 28. This small lead comprises a Brent reservoir in a downthrown trap sealed by the Humber Group with lateral seal against the Dunlin Group. The depth of burial of the Brent reservoir in this lead would suggest that the Brent Group is likely to be of good quality. Updip of the Caliban North prospect is the aforementioned dry Halibut High. Due to the proximity of this lead to the Halibut High there is a significant lateral seal risk and/or the prospect being off the migration pathway.

A new interpretation of Caliban North shows a higher degree of compartmentalisation than was observed on the original data.

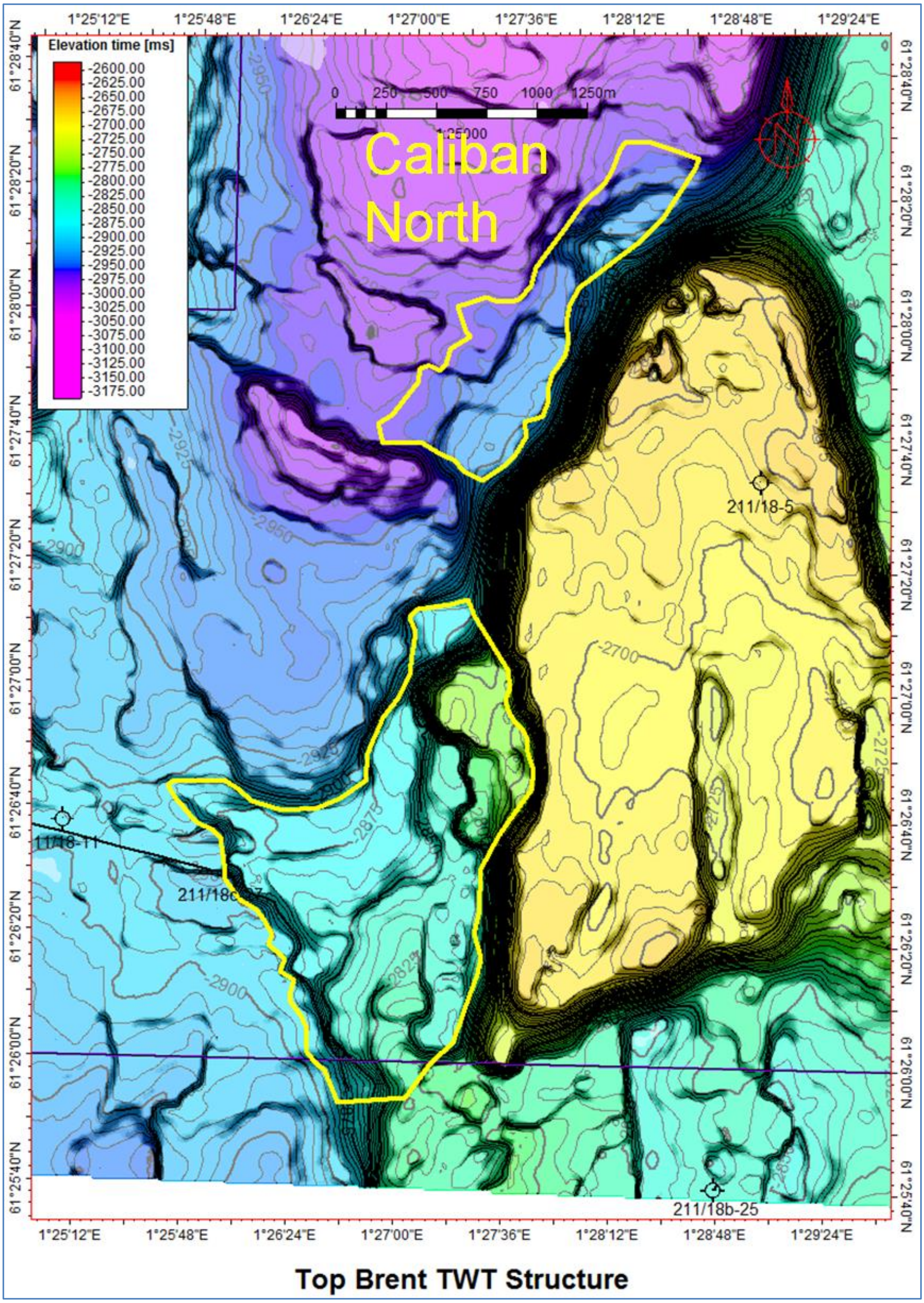

Figure 27: Caliban North Top Brent Map

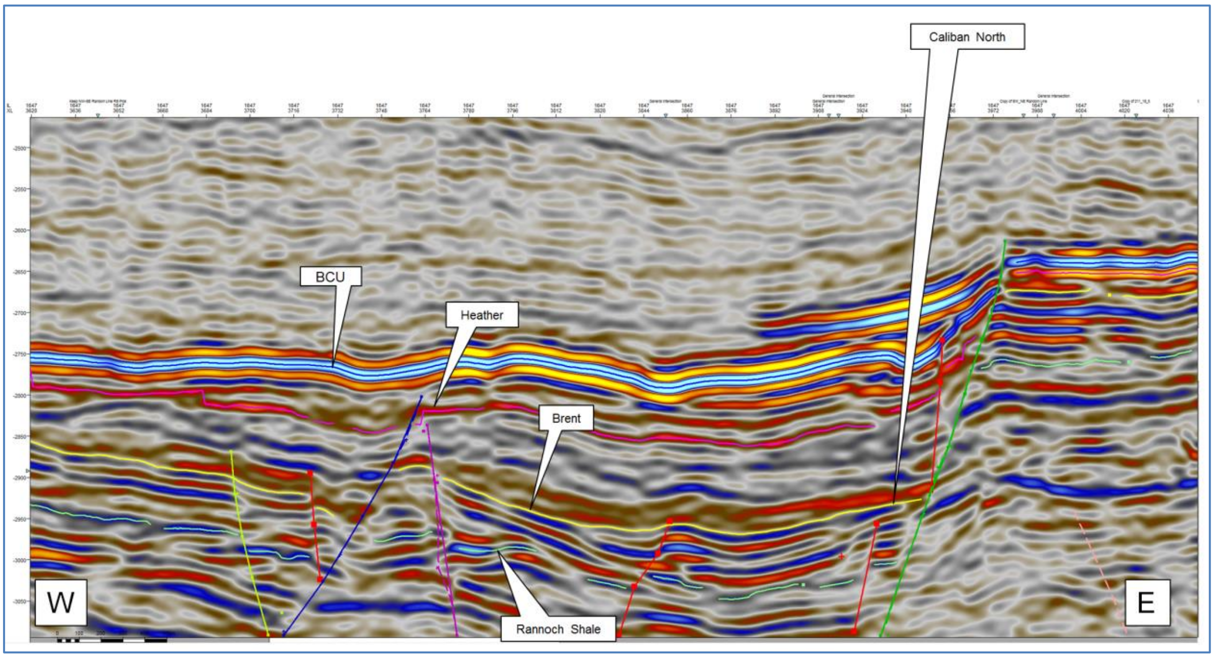

Figure 28: Caliban North W-E Cross Section

Buchat

The Buchat Lead was not identified at the time of application. It is Brent lead and is a 3 way dip closure against a NE-SW trending fault north of the Don SW accumulation. A map of the lead is shown in Figure 29 and a seismic profile from Don SW through Buchat is shown in Figure 30. It lies just within the P2201 licence but the crest is some 4.75 kms North of the Don SW drill centre.

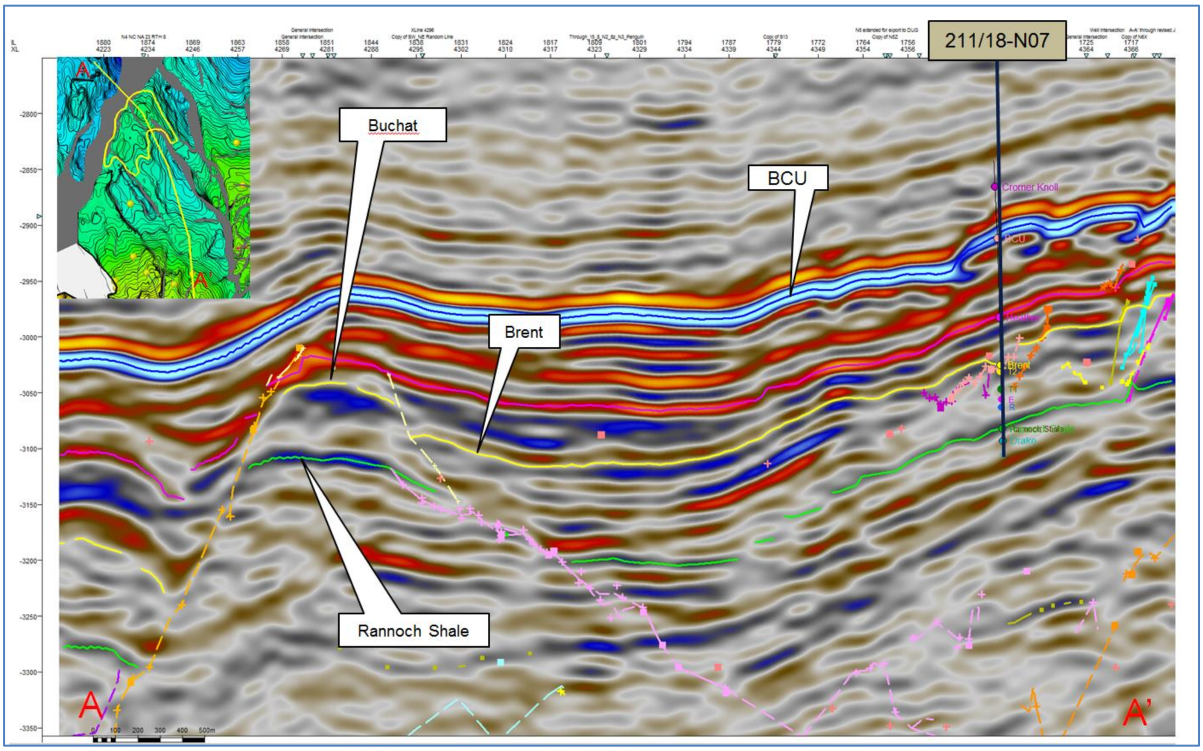

Figure 29 Seismic Traverse through Buchat

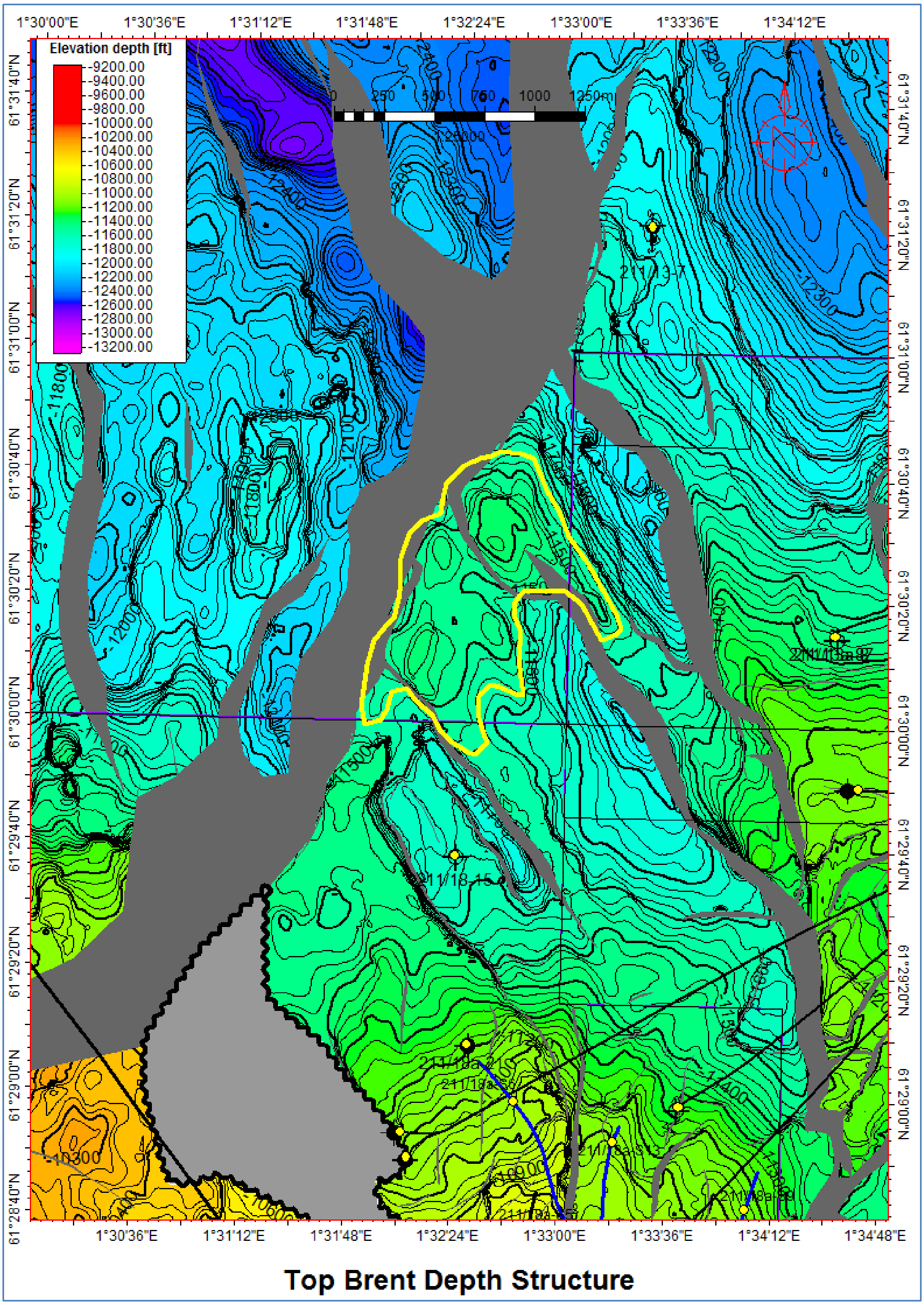

Figure 30: Buchat Lead

There is a good chance of encountering Brent reservoir, although potentially poorer quality due to depth but there is a possibility that Buchat may be in a migration shadow, should migration to DonSW come via Penguins E to the NE, as is believed to be most likely.

	Buchat (ML)	Caliban Central (ML)	Carvie (ML)	Caliban North (ML)
Area (km^2)	0.7	1.7	9	0.6
Height of closure (ft)	150	350	900	212.5
Net reservoir (ft)	120	235	4	250
Net:gross (%)	0.8	55	100	55
Gross rock volume (MMm^3)	12	55	37	5
Porosity (%)	16	14	16	14
Hydrocarbon saturation (%)	60	70	50	70
Formation volume factor	1.36	1.2	1.3	1.2
Recovery factor (%)	30	30	25	30
Oil in place (mmbo)	**4.2**	**15.5**	**14.5**	**1.5**
Resources (mmbbl)	**1.3**	**4.6**	**3.6**	**0.5**

Table 14: Deterministic input parameters & resulting STOIIP/Resources

Risk Parameter	Buchat	Caliban Central	Carvie	Caliban North
Reservoir (%)	80	100	25	100
Seal (%)	80	50	100	50
Trap (%)	90	40	100	50
Charge (%)	60	40	100	60
Pg (%)	35	8	25	15

Table 15: Leads Risks

Updated Summary of Prospect

Remapping of Caliban Central and Caliban North shows potentially more compartmentalisation than mapped previously.

The Buchat lead is potentially compartmentalised. All leads are too far away from the Don SW drill centre to provide the opportunity for a long reach well.

Enquest, therefore, believes that all the identified leads are uneconomic based on current or predicted oil prices.

7 Further Technical Work Undertaken

Seismic Reprocessing by WGC of 250 sq. kms over the Greater Dons was initiated, covering much of the licence and including enhanced multiple reduction and Kirchhoff Anisotropic Pre Stack Depth Migration. This data was then used as input to create Spectrally Blued and Colour Inverted volumes. Remapping of this data was then undertaken, primarily on the Spectrally Blued data, to help better define the risks of the identified prospectivity.

A Basin Modelling study was undertaken by EnQuest to determine likely migration pathways and to better understand the likelihood that hydrocarbons having reached the identified leads and prospects.

A Shallow Gas study was undertaken using the seismic data to identify any near field gas accumulations. None of substance were evident.

8 Resource and Risk Summary

Resource and Risk Summary										
Prospect Lead Discovery Name	PLD	Stratigraphic Level	Unrisked recoverable resources						Geological Chance of Success (%)	Risked P50 (MMboe)
			Oil (MMbbls)			Gas (BCF)				
			Low	Central	High	Low	Central	High		
Mossat		Brent	0.6	1.6	4.6				61	0.98
		Banks	0.35	0.8	1.98				41	0.33
Buchat		Brent		1.3					35	0.44
Kindle		Brent	3.7	7.7	17.5				4	0.31
Caliban North		Brent		0.5					15	0.08
Caliban Central		Brent		4.6					8	0.37
Carvie		Magnus Sst		3.6					25	0.9

Table 16: Summary Table of recoverable resources

9 Conclusions

A review of the identified prospectivity was undertaken on newly reprocessed seismic data. In all cases (except for Carvie), the risks associated with the leads and prospects increased, either as a result of increased compartmentalisation observed on the seismic data or, in the case of Kindle, a recognition of the increased risk of reservoir presence.

Given the current and forecast oil price, all these leads are considered uneconomic and therefore unattractive as drilling candidates.

10 Clearance

EnQuest approves the release of this document by OGA.