Confidential report for:

Cluff Natural Resources

Competent Person's Report of the Hydrocarbon Interests of Cluff Natural Resources in the Southern North Sea,U.K.

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Prepared for:

Cluff Natural Resources
5-8 The Sanctuary
Westminster
London
United Kingdom
SW1P 3JS

By:

Axis Well Technology
Office 243, Building 3,
Chiswick Park
566 Chiswick High Road
Chiswick
London
UK
W4 5YA

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EXECUTIVE SUMMARY

Introduction

The assets reviewed by Axis are located offshore in the Southern North Sea gas basin of the U.K. CNR currently have a 100% interest in five promote[1] licences consisting of eleven blocks or part blocks as summarised in **Table A1**.

Asset (Blocks)	Operator	Interest (%)	Status	Licence Expiry Date	Licence Area km^2	Comments Licence Commitment
P2252 (41/5, 41/10, 42/1)	CNR	100%	Promote Licence	December 2016	715.0	Obtain and reprocess 10km of 2D seismic
P2261 (43/7, 43/8, 43/9)	CNR	100%	Promote Licence	December 2016	716.5	Obtain and reprocess 10km of 2D seismic
P2248 (43/11)	CNR	100%	Promote Licence	December 2016	239.8	Obtain and reprocess 10km of 2D seismic
P2253 (42/14b)	CNR	100%	Promote Licence	December 2016	223.9	Obtain and reprocess 10km of 2D seismic
P2259 (43/3b, 43/4b, 43/5)	CNR	100%	Promote Licence	December 2016	523.1	Obtain and reprocess 10km of 2D seismic

Table A1: CNR Licence Summary

The licences are prospective for gas in a number of reservoirs within the Triassic (Bunter sandstones), Permian (Zechstein carbonates and Rotliegendes sandstones) and Carboniferous (Dinantian, Namurian and Westphalian sandstones). They have been assessed for prospective resources at the prospect, lead and play levels. There are currently no fields or discoveries on the licences to qualify for reserves or contingent resources. However, the well 42/10a-2, drilled on the Lytham prospect in licence P2252, did encounter gas in Permian and Carboniferous reservoirs. The Forbes field, in block 43/8 (licence P2261), has been decommissioned and production ceased in 1993. Most of the area within licence P2259 and block 43/9 in licence P2261 are subject to planned windfarms and have not been considered further for prospective resources.

[1] A promote licence is a variant of the Seaward Production Licence designed to allow small- and start-up companies a Production Licence first and to attract the necessary operating and financial capacity later. The difference is seen more in the application process than the licence itself, except in that the annual rental rate on a Promote Licence is reduced by 90% for 2 years. The licence requires financial, technical and environmental capacity to be in place, and a firm drilling (or agreed equivalent equally substantive activity) commitment to have been made by the end of the second year – or the licence will expire at that time. The licence expiry date refers to the current 'promote' period which will be extended as a 'traditional' licence should all the transition criteria be met.

The licences have been relatively underexplored as they lie to the north of the proven prolific gas fairways and towards the edge of the basin which has historically been considered to have low prospectivity. However, recent nearby Carboniferous discoveries, such as Pegasus in 43/13b and Crosgan in 42/10b and 42/15a have upgraded the potential of the area.

In addition, there are two large fields Breagh and Cygnus, with ultimate reserves in excess of 600 Bscf, which lie close to the south of the licence areas. The Breagh field came on stream in 2013 with gas in Carboniferous Dinantian reservoirs. First production is anticipated in 2016 from the Cygnus field with gas in Permian Rotliegendes and Carboniferous Westphalian reservoirs. It is also anticipated that several of the recent discoveries will be developed resulting in infrastructure and gas pipelines close to the licence areas. These recent developments and discoveries have rekindled exploration interest in the northern part of the basin.

The effective date of the report is 1st November 2015 which is the cut-off date for all geological, engineering and financial data after which no new information can be included in the evaluation. This CPR assesses the resources of the prospects and leads based on legacy reports made available to Axis by CNR. Axis has critically reviewed the interpretations and maps provided and, where necessary, has performed independent evaluations. All resource and risk assessments have been independently assessed by Axis.

Prospective Resources: Technical Evaluation

Prospects and leads have been assessed for Zechstein and Carboniferous gas resources on licence P2252 (blocks 41/5 and 41/10) and for Rotliegendes and Triassic gas resources on block 43/7 (licence P2261). Where no specific prospects or leads have been identified at a reservoir level, Axis has assessed the licence resource potential at the play level. This assessment has been made for the Carboniferous potential in licences P2253 (Block 42/14b), P2248 (block 43/11) and P2261 (blocks 43/7 and 43/8). The licences are prospective at several stratigraphic horizons and the geological and geophysical studies by CNR are currently at a preliminary stage. It is therefore likely that further prospects and leads will be identified as studies progress. The prospective resources at the prospect, lead and play levels are described in detail in **Sections 2-5** of this report.

On licence P2252, two wells, 41/5-1 and 42/10a-2, discovered gas in the Permian Zechstein and/or Carboniferous reservoirs. However, due to technical failures, the flow test results for both wells were inconclusive so Lytham, in 41/10, and Fairhaven, in 41/5, are considered for prospective resources pending further drilling and / or testing. A lead, St Anne’s, is also assessed for prospective resources.

Licences P2253 (block 42/14b) and P2248 (block 43/11) lie towards the central region of quadrants 42 and 43 to the north of a number of gas fields. Gas has been found in several stratigraphic horizons in the area from the Carboniferous, Permian and Triassic. Significant fields include the Cygnus Permian field and the depleted Esmond and Forbes Triassic fields to the east and the Breagh Carboniferous field to the west.

Recent important Carboniferous discoveries include Pegasus (43/13b) and Crosgan (42/10b and 42/15a). Seismic mapping by CNR is at an early stage in the area but a number of attractive features have been identified and the Carboniferous potential is considered for prospective resources at the play level.

P2259 consists of blocks 43/3b, 43/4b and 43/5 and lies towards the northern edge of the basin. The area is potentially prospective especially in the Carboniferous. However, Axis understands from CNR that planning permission has been granted for a large scale offshore windfarm over a significant proportion of the licence area. Currently there is no clear timetable for actual construction of the windfarm and it may impact CNR's ability to develop the P2259 licence. Consequently very little work has been done in this area and so for the purpose of this report P2259 has not been included.

Licence P2261 comprises blocks 43/7, 43/8 and 43/9. Block 43/8 includes the old, Forbes gas field which was productive from Triassic Bunter sandstones. The area lies close to Permian and Carboniferous producing fields such as Cygnus (44/11) and Cavendish (43/19). The eastern region of the licence in block 43/9 is within proposed wind farm areas. Two features, in 43/7, Williamson (Triassic) and Clachnaharry (Permian), previously identified by the previous operator, have been proposed by CNR and have been assessed for prospective resources at the lead level. There is also significant Carboniferous potential on the licence as indicated by the recent Crosgan and Pegasus discoveries and the potential is considered for prospective resources at the play level.

Prospect Resource Assessment

The prospective resources for the prospect and leads evaluated by Axis are reported in **Tables A2 and A3**. It should be noted that there is no certainty that any portion of the prospective resources will be discovered, and, if discovered, there is no certainty that it will be developed, or, if it is developed, there is no certainty as to either the timing of such development or whether it will be commercially viable to produce any portion of the resources.

The volumes reported in **Table A2** are for the Lytham and Fairhaven prospects in licence P2252. CNR have 100% on these licences and so the gross on licence is the same as the net working interest.

Prospective Gas Resources for the Prospects in Licence P2252 (Bscf)								
Prospect	Gross on Licence			Net Attributable			Risk Factor %	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Lytham Permian	12	52	195	12	52	195	51	CNR
Lytham Carboniferous	12	44	149	12	44	149	30	CNR
Fairhaven	**9**	**36**	**125**	**9**	**36**	**125**	26	CNR
Total Gas	**33**	**132**	**479**	**33**	**132**	**479**		

Table A2: Prospective Resources in the Prospects Gross and Net[3]

[3] **Net Attributable** is net working interest to CNR and is not necessarily the same as net entitlement. Net working interest is that portion of the gross resources attributable to the equity interest owned by CNR. Net entitlement will depend on the contractual terms of the licence at the time of any eventual hydrocarbon production.
Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Prospective resources are the volumes expected to be recovered from UPIIP (undiscovered petroleum initially in place) under conceptual projects, conditional on discovery and development.
Low, Best and High Estimate: in a probabilistic resource size distribution these are the P_{90} (90% probability), P_{50}, and P_{10}, respectively, for individual opportunities.
Risk Factor for prospective resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the prospective resource maturing into a contingent resource. Prospective resources have both an associated chance of discovery (geological chance of success) and a chance of development (economic, regulatory, market and facility, corporate commitment and political risks). The chance of commerciality is the product of these two risk components. These estimates have been risked for chance of discovery but not for chance of development.
Totals do not take account of prospect dependencies and have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.
The gross mean resource unrisked volumes are 85 Bscf for Lytham Permian, 67 Bscf for Lytham Carboniferous and 56 Bscf for Fairhaven Prospect. The combined unrisked arithmetically summed “mean” gross prospective resource potential is 208 Bscf.

Lead Resource Assessment

The volumes reported in **Table A3** are for the St Anne's lead in P2252 and the Clachnaharry and Williamson leads in licence P2261. CNR have 100% on these licences and so the gross on licence is the same as the net working interest.

Prospective Gas Resources for the Leads in Licence P2261 (Bscf)								
Lead	**Gross on Licence**			**Net Attributable**			**Risk Factor %**	**Operator**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**		
St Anne's Permian	4	14	52	4	14	52	20	CNR
St Anne's Carboniferous	4	16	58	4	16	58	12	CNR
Clachnaharry	9	43	207	9	43	207	12	CNR
Williamson	10	20	40	**10**	20	40	27	CNR
Total Gas	**27**	**93**	**357**	**27**	**93**	**357**		

Table A3: Prospective Resources in the Leads Gross and Net (see Table A2 footnotes)[4]

Further seismic and studies by CNR are likely to result in new potential traps being identified and some may be matured to drillable prospects; some previous leads may not be confirmed.

Play Resource Assessment

Axis has assessed the play prospective resource potential for the Carboniferous in licences P2248, P2253 and P2261. The play level assessment method used has considered the resource size range for a hypothetical trap, the trap density and the chance that the play will be successful on the licence.

The Carboniferous play is currently unproven within these licences although it is proven in the area for example in the nearby Breagh field, Pegasus and Crosgan discoveries and several fields in quadrants 43 and 44 further to the south. The evaluation of the Carboniferous play in these licences by CNR is at an initial stage and no prospects and leads have currently been identified that may be evaluated for prospective resources at the prospect or lead level.

[4] **The gross mean** resource unrisked volumes are 23 Bscf for St Anne's Permian, 26 Bscf for St Anne's Carboniferous, 86 Bscf for Clachnaharry and 23 Bscf for Williamson Lead. The combined unrisked arithmetically summed "mean" gross prospective resource potential is 158 Bscf.

However, the Carboniferous play is considered very prospective and Axis have therefore assessed the potential at the play level as defined by PRMS guidelines (Appendix 2).

The reservoir parameters and resource estimates have been benchmarked against the fields and discoveries in the area. Axis has assessed the play exploration resource potential by combining the typical field resource size with an estimate of the possible average trap density benchmarked with the producing areas in the basin, to the south of the CNR licences.

The assigned risks are attributable at the play level and indicate the chance that the Carboniferous play is viable on block. The play chance of success considers reservoir, seal and gas charge. The play chance of success does not take into account any prospect related risks. The prospect chance of success considers prospect specific risks for trap, seal, reservoir and charge. It is possible that given a well-defined structure based on good quality seismic, that the prospect chance of success may be in the range of 10-20% for the Carboniferous play.

Prospective Gas Resources for the Carboniferous Play in P2248, P2253 and P2261 (Bscf)								
Licence	**Gross on Licence**			**Net Attributable**			**Play Risk Factor %**	**Operator**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**		
P2253	85	170	255	85	170	255	medium	CNR
P2248	90	180	270	90	180	270	medium	CNR
P2261	90	270	450	90	180	270	medium high	CNR
Total Gas	**265**	**620**	**975**	**265**	**620**	**975**		

Table A4: Prospective Resources for the Carboniferous Play Gross and Net[6]

[6] This is the product of the multiplication of the trap number by the P_{50} resource size. This is equivalent to arithmetically summing the best case values for individual opportunities. This estimate is unrisked. The estimated number of Carboniferous traps that are predicted to be identified in this structural setting from extensive good quality seismic data coverage, is assumed to be in the range of 1 to 3 in each of blocks 42/14b and 42/11. For licence P2261, (blocks 43/7 and 43/8) the number of traps are assumed to be in the range of 1 to 5; the potential in block 43/9 has been neglected.
The risk refers to the chance of success of the play on the licence. The play chance of success does not take into account additional prospect related risks.

Resource and risk assessment is a data driven process and lack of data is reflected in increased risk and a wider resource size range. Consequently we would expect new data and studies to significantly reduce both the risk and uncertainty for potential traps. Both geochemical modelling and reservoir studies have the potential to reduce hydrocarbon charge risk and the reservoir parameter input uncertainty, respectively. Drilling by other operators in neighbouring areas is likely, leading to further risk reduction if these drilling programmes are successful. Further seismic acquisition and reprocessing by CNR will likely result in potential traps being identified and some may be matured to drillable prospects.

Reconciliation to last Historic Statement

Axis is not aware of any previous reporting by CNR of the resource potential of these assets to the AIM stock market.

QUALIFICATION AND SIGN-OFF

Title	Name	Signed	Date
Principal Geoscientist	Dr Martin Eales		01/12/2015
Principal Petrophysicist	Andrew Foulds		01/12/2015
Principal Reservoir Engineer	Peter Aldersley		01/12/2015
Principal Production Technologist	Karl Bird		01/12/2015
Principal Geologist/ Peer Review	Katrine Holdoway	Katrine Holdoway	01/12/2015
Senior Reservoir Engineer	Andrea Lovei		01/12/2015
Technical Assistant	Abi Clarke		01/12/2015
General Manager	Max Harper		01/12/2015
Director	Alastair Dodds		01/12/2015

Appendix 1 contains qualification summaries.

Document	**Cluff Natural Resources CPR 001**		
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Company	**Position**
Axis Well Technology	Axis on file

1.0 INTRODUCTION

1.1 Scope of Investigation

This Competent Person's Report (CPR) was prepared by Axis Well Technology Ltd (Axis) in November 2015 at the request of the Directors of Cluff Natural Resources plc (CNR).

This report details a review of the licence interests and prospective resources attributable to the assets of CNR in the Southern North Sea (SNS) of the United Kingdom continental shelf (UKCS) (**Figure 1.1**). CNR have five promote licences consisting of eleven blocks or part blocks and are summarised in **Table 1.1**. The licence awards were announced by DECC (Department of Energy and Climate Change) in December 2014 in the 28th Seaward Licencing Round. The licences are prospective for hydrocarbons in a number of reservoirs within the Triassic, Permian and Carboniferous (**Figure 1.2**).

This CPR assesses the resources of the prospects and leads based on legacy reports made available to Axis by CNR. There is significant additional exploration potential on the assets. The area is prospective at several stratigraphic horizons and the geological and geophysical studies by CNR are currently at a preliminary stage. It is therefore likely that further prospects and leads will be identified as the studies progress. Where no specific prospects or leads have been identified, Axis has assessed the licence resource potential at the play level.

1.1.1 Overview of the Assets

The western area, licence P2252, is situated towards the north western edge of the Southern North Sea (SNS) basin and consists of three blocks 41/5, 41/10 and 42/1. The licence lies approximately 50 km from the Yorkshire coast in shallow water depths in the range of 80 m. Two wells on the licence discovered gas in the Permian Zechstein and / or Carboniferous reservoirs. However, due to technical failures, the flow test results for both wells were inconclusive so the two traps, Lytham, in 41/10, and Fairhaven, in 41/5, are considered for prospective resources pending further drilling and / or testing. A lead, St Anne's, is also assessed for prospective resources.

Two licences, P2253 (block 42/14b) and P2248 (block 43/11), lie towards the central region of quadrants 42 and 43 in a prolific area of the SNS close to a number of gas fields, infrastructure and pipelines to shore. Water depth is 60-70 m. Gas has been found in several stratigraphic horizons in the area from the Carboniferous, Permian and Triassic. Significant fields include the depleted Esmond and Forbes Triassic fields to the east and the Breagh Carboniferous field to the west (**Figure 1.1**).

Recent important discoveries include Pegasus in 43/13b and Crosgan in 42/10b and 42/15a. Seismic mapping by CNR is at an early stage in the area but a number of attractive features have been identified and the Carboniferous potential is considered for prospective resources at the play level.

The remaining two licences, P2261 and P2259, lie towards the northern edge of the SNS basin in the UKCS. P2259 consists of blocks 43/3b, 43/4b and 43/5. The area is potentially prospective especially in the Carboniferous. However, Axis understands from CNR that planning permission has been granted for a large scale offshore windfarm over a significant proportion of the licence area. Currently there is no clear timetable for actual construction of the windfarm and CNR continues to review the situation which may impact CNR's ability to develop the P2259 licence. Consequently, limited work has been done in this area to date and so, for the purpose of this report, P2259 has not been included.

Licence P2261 comprises blocks 43/7, 43/8 and 43/9. Block 43/8 includes the old, Forbes gas field which was productive from Triassic Bunter sandstones. The eastern region of the licence in block 43/9 is within proposed wind farm areas. Two features, in block 43/7, Williamson (Triassic) and Clachnaharry (Permian), previously identified by the previous operator, have been proposed by CNR and have been assessed for prospective resources at the lead level. Water depth in block 44/7 is in the range of 20-30 m and the area lies close to infrastructure associated with a number of depleted fields (e.g. Forbes (43/8) and Esmond (43/13), producing fields (e.g. Cygnus (44/11) and Cavendish (43/19) and a number of recent discoveries (e.g. Crosgan (42/10) and Pegasus (43/13).

The prospective resources as of 1st November, 2015 are described in detail in **Sections 2-5** of this report.

CNR's alliance with Halliburton will potentially provide access to leading edge technologies such as directional drilling, geo-steering, drilling fluids optimisation and well completions. For example in the fractured Zechstein dolomites, Halliburton (or similar) could potentially design and implement managed-pressure solutions to reduce reservoir damage.

1.2 Legal Overview, Licence and Environmental Details

Table 1.1 details the licences held by CNR as at 1st November 2015 in the UKCS Southern North Sea Basin and the main licence terms including the expiry date of the initial period.

Asset (Blocks)	Operator	Interest (%)	Status	Licence Expiry Date	Licence Area km^2	Comment Licence Commitment
P2252 (41/5, 41/10, 42/1)	CNR	100%	Promote Licence	December 2016	715.0	Obtain and reprocess 10km of 2D seismic
P2261 (43/7, 43/8, 43/9)	CNR	100%	Promote Licence	December 2016	716.5	Obtain and reprocess 10km of 2D seismic
P2248 (43/11)	CNR	100%	Promote Licence	December 2016	239.8	Obtain and reprocess 10km of 2D seismic
P2253 (42/14b)	CNR	100%	Promote Licence	December 2016	223.9	Obtain and reprocess 10km of 2D seismic
P2259 (43/3b, 43/4b, 43/5)	CNR	100%	Promote Licence	December 2016	523.1	Obtain and reprocess 10km of 2D seismic

Table 1-1: CNR Licence Summary[8]

Note: the licence expiry dates refer to the current 'promote' period which will be extended as a 'traditional' licence should all the transition criteria be met.

The licence details were supplied by CNR and are believed to be valid at the effective date of this report. Axis has not reviewed the legal status and licence documents and hence does not make any statement as to the ownership, contractual or legal terms of these licences.

The licences require financial, technical and environmental capacity to be in place, and a firm drilling (or agreed equivalent equally substantive activity) commitment to have been made by the end of the second year (December 2016) – or the licence will expire at that time, or potentially extended by negotiation with the Oil and Gas Authority (OGA).

Environmental and abandonment requirements as required by the UKCS regulation authority will be met by CNR. Environmental Impact Assessments will be conducted as prescribed in the licence terms and will be required before drilling.

[8] The licence information has been supplied by CNR.

The current early stage of exploration activity in the concession means that there are presently no facilities of material significance that would require significant abandonment plans. Any possible future facilities will be subject to abandonment and associated environmental protection matters as prescribed in the licence terms and the laws of the U.K.

The licences lie close to infrastructure and gas pipelines. The SEAL (Shearwater Elgin Area Line) pipeline passes through blocks 47/3b and 47/8 to join with the ETS (Esmond Transmission System) pipeline to the Bacton Terminal on the Norfolk coast. The Langeled pipeline passes by block 42/14b and transports Norwegian natural gas to the terminal at Easington on the Lincoln coast.

The company (CNR) is responsible for preventing pollution and protecting the environment and the living resources of the sea. It is also to ensure prompt, fair and adequate compensation for injuries.

In support of operations, power and water supplies are the responsibility of CNR and the contractors.

The Operator is responsible for putting in place programmes to deal with potential health and safety issues and require that its contractors also have such programmes.

Axis is not aware of any special or exceptional factors affecting the exploration or extraction businesses of the licence.

1.2.1 Sources of Information

The content of this report and the Axis resource estimates are based on data provided by CNR. Axis has accepted, without independent verification, the accuracy and completeness of this data.

The available data comprised principally of legacy well and seismic data together with block evaluation and relinquishment reports in the public domain. The detailed data available for review by Axis is noted in the body of the report.

The review was partly based on geological, geophysical and petrophysical studies made available by CNR, and partly based on peer-reviewed geological and geophysical studies from the public domain.

Information on possible development plans and associated costs were not provided by CNR at this stage. However, this report does include a chapter on pertinent current production and development technology drawing upon analogues in the public domain.

The data provided was, in Axis's opinion, complete and suitable for the purposes of this initial evaluation. Any data limitations and implications are noted in the asset description section of this report.

The key reports and sources of information received from the client included, but not limited to, the following:

- CNR 28th Round application, 2014
- CNR board presentation documentation
- Licence relinquishment reports
- Published papers on the Triassic, Permian and Carboniferous reservoirs
- CPR on the UKCS assets of Trap Oil Ltd, Challenge Energy Limited, 2011.
- CNR proprietary geological reports and maps.
- Petrophysical observation summaries on 12 wells. Data type and quality available from historic wells limited the ability to undertake detailed petrophysical analysis in certain formations.
- Released wireline and LWD data and reports on 20 wells.
- Two 3D seismic surveys and regional 2D seismic lines supplied as a Kingdom project.
- Initial seismic interpretations by CNR and evaluation reports by Lyme Bay consultants for CNR.

1.2.2 Requirements

As per CNR's instructions, Axis confirm that:

- it is independent of CNR plc "("the Company"), its advisers, senior management and directors.
- it will be recompensed via a time-based fee and not via a charge that is linked to the value of the Company in any way;
- is not a sole practitioner;
- has the relevant experience, appropriate qualifications and technical knowledge to appraise independently and professionally the assets: being all assets, joint ventures, licences or other arrangements owned by the Company. This includes assets proposed to be exploited or utilised by it (the "Assets") and the liabilities: all liabilities, contractual agreements, royalties and minimum funding required relating to the Company's work programme (the "Liabilities").
- the authors are professionally qualified and members in good standing of a self-regulatory organization of geoscientists and/or engineers;
- the authors have at least five years relevant experience in the assessment, estimation and evaluation of hydrocarbon assets;

1.3 Consent

Axis consent to [and have not withdrawn such consent at the date of publication]:

- the inclusion of this report (or a summary of portions of it) in documents prepared by CNR and its advisers;
- the electronic publication of this report on public websites including the CNR website;

the inclusion of the name of Axis Well Technology in documents prepared for commercial or financial activities.

Except with permission from Axis, this report may not be reproduced or redistributed, in whole or in part, to any other party, or published, in whole or in part, without the written consent of Axis.

1.4 Effective Date of Evaluation

The effective date of the report is 1st November, 2015 which was the cut-off date for all geological, engineering and financial data after which no new information has been included in the evaluation.

1.5 Basis of Opinion

General

The report demonstrates Axis's best professional investigation and is not to be considered a guarantee or prediction of results.

It represents what can be achieved given the input data, time allowed and scope of work. There is no guarantee that a more in-depth report would not contain more information.

The use of this material and report is at the user's own discretion and risk and Axis shall have no liability from this report**.** The information in this report must be considered in its entirety.

Axis is not responsible to update this report in view of either events or circumstances occurring after the effective cut-off date. Because the evaluation is based on judgements regarding future events, actual results will vary and the variations may be material.

Standards

This report has been generated by Axis using the definitions and guidelines laid out in the 2007 and 2011 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

The results of this project have been displayed in agreement with the requirements of the AIM Market of the London Stock Exchange and the European Securities and Market Authority (ESMA), specifically as in the "Note for Mining and Oil and Gas Companies - June 2009".[1-7]

Financial

The report relates specifically and solely to the reviewed assets and is conditional upon various assumptions that are described herein. The report must be read in its entirety. This report was provided for the sole use of CNR on a fee basis. There is no other related commercial arrangement between Axis and CNR.

This assessment has been completed within Axis's understanding of legislation, taxation and other regulations on the block reviewed in this report. Axis has not verified property / title rights or their conditions including financial interests.

Technical

In preparing this report, Axis has used all reasonable skill and care to be expected of a professional consultant. Axis does not think that CNR has withheld information. The data and images supplied are the responsibility of CNR management. It is the responsibility of Axis to express an opinion on the supplied data and images based on its independent evaluation.

All interpretations and conclusions are opinions based on geological, geophysical, engineering or other data. The accuracy of estimates of volumes of oil and gas are a result of the quantity and quality of the data and images made available by the client and from public sources. Axis has accepted, without performing an independent check, the accuracy and completeness of these data and images.

Resource estimates are believed to be reasonable but they should be accepted on the basis that subsequent asset performance may require revision. There is no guarantee that the prospective resources will be discovered or that they will be commercially viable.

Axis has not reviewed the HSE arrangements for the assets neither does it make any comment on country or political risk in this evaluation.

No site visit was carried out on the blocks reviewed in this report as there were no active facilities or wells to examine.

Material Change

As far as Axis knows, there has been no material change of circumstances or available information since the effective date of this report.

Axis is not aware of any significant matters, which might be of a material nature arising from our evaluation, that are not covered within this report prior to publication.

Because resource data are based on judgements regarding future events, actual results will vary and the variations may be material.

2.0 LICENCE P2252

2.1 Geological Setting

Licence P2252 consists of blocks 41/5, 41/10 and 42/1 which lie on the northwestern margin of the U.K. Southern North Sea (SNS) basin. Several fields and discoveries occur in the area and many other wells have indications of gas pay or gas shows. The primary prospective reservoirs on the licence are believed to be in the Carboniferous (Namurian and Dinantian) and the Upper Permian (Zechstein) (**Figures 1.2 and 2.1**).

The Breagh field (42/12 and 42/13) lies 35 km to the southeast with gas reserves believed to be in the order of 700 Bscf in lower Carboniferous (Dinantian) sandstones and the Crosgan discovery (42/10) lies 50 km to the east with gas resources circa 100 Bscf (**Figure 1.1**). Several wells had good shows or indications of pay in the Carboniferous including 42/10-2 drilled on the licence. A number of large Carboniferous gas fields lie further to the east in quadrants 43 and 44 (e.g. Murdoch, Schooner and Hawksley) and several small Carboniferous oil and gas fields lie onshore in Yorkshire and Lincolnshire (e.g. Welton, Beckingham and Gainsborough).

Zechstein reservoirs, with interpreted gas pay, or gas shows as identified on mudlogs, were encountered in the area, including the three wells drilled on the licence. Nearby wells with reported gas in the Zechstein include 41/15-1, 42/16-1, 41/20-1, 41/20-2, 41/18-1 to the south west and onshore fields include Eskdale, and Lockton. Well 42/9-1, to the south east, also encountered gas pay in the Hauptdolomite. The best recorded flow rates were from Conoco's 41/24a-1 and 41/25a-1 which tested gas from the Plattendolomite. Conoco 41/24a-2z was a horizontal well and is believed to have tested gas at circa 100 MMscfd. Production from the Zechstein in the Hewett field area (48/29, 48/30) has occurred from the 1980's.[8]

2.1.1 Reservoir

The presence of middle and lower Carboniferous sandstones (**Figure 1.2**) is confirmed by all three wells drilled on the licence: 41/10-1, 41/10-2z and 41/5-1. However, the effectiveness of potential reservoirs is still to be proven as the wells were not tested at these intervals. The Carboniferous consists of a number of stacked sand and shale intervals with potential intra carboniferous seals. The Namurian, in well 41/10-2z, indicates stacked sandstones with a net to gross of over 30%.

The Namurian is likely to be absent from the high areas on the licence with Hercynian erosion into the Dinantian as in 41/10-1. Tertiary uplift is likely to be of the order of 1-2 km. Deeper lower Carboniferous intervals are also potential reservoirs with thick sandstone development although reservoir quality may not be sufficiently high especially at depths below 3000 m. Well 41/10-1 encountered thick sandstones in the lower Carboniferous Yoredale, Scremerston and Fell Sandstone formations (**Figure 1.2**). The Yoredale sandstones in 41/10-1 are interpreted with over 60 m net sandstone in a number of sandstone intervals with porosities in the range of 6-13%. Thick sandstones also exist in the Fell Sandstone Formation but reservoir quality is expected to be very low at the objective depths except where characteristics are substantially improved due to early dissolved pore space feldspar by early migrant fluids.

The lower Permian (Rotliegendes) is generally absent in the area although isolated sandstone development is possible. The primary reservoirs consist of the Plattendolomite and the underlying Hauptdolomite in the upper Permian Zechstein (**Figure 2.1**). In the wells on the licence, the Plattendolomite is nearly 100 m thick and the Hauptdolomite is of the order of 50 m. Most of the production in the basin is from the Z2 Hauptdolomite although there are some resources attributable to the Z3 Plattendolmite. The well results in all the wells on the blocks indicate potentially good, to very good, localised reservoirs probably associated with secondary porosity, vugs and fracturing. Localised diagenesis can be both positive, through the formation of secondary porosity, and be detrimental through the occlusion of the pore space by halite and anhydrite cements. The effectiveness of the reservoir has not yet been adequately proven by testing on the licence. Petrophysical analysis of the Zechstein has been historically problematic and reservoir potential may be underestimated especially in fractured areas. Commonly, zones with poor porosity may have enhanced fracture permeability due to the brittle nature of the relatively tight and massive carbonates.

Seismic analysis indicates potential thick areas of Zechstein are developed within the licence area and are interpreted to be associated with carbonate build-ups lying between the shelfal and basinal facies. This facies belt, lying to the south of the Mid North Sea High, has not been tested on the licence and has been inadequately explored in the area. It is likely that this facies could indicate sweet spots for fracturing and enhanced reservoir development. This play has been successively pursed in the Netherlands for example by Shell and in Permo-Carboniferous carbonate plays in other basins in the world. Prospects associated with this play are currently being developed by CNR and so are not reported here as prospective resources. Further details are in **Appendix 4**.

2.1.2 Charge

One or more regional sources for gas and effective charge are proven by the three wells on the licence, all of which indicate gas. The gas is methane rich and some oil and condensate have also been encountered in the basin. Inerts and hydrogen sulphide are also present in some discoveries especially respectively in the Triassic and Zechstein plays. The source for the gas is believed to be coal rich intervals in the Carboniferous either from the coal measures of the Westphalian (upper Carboniferous) or the deeper coals in the lower (Dinantian) and marine shales of the middle (Namurian) Carboniferous. The Westphalian is absent in the area by erosion so gas charge from this source requires long distant migration which may be problematic especially into the older middle and lower Carboniferous sandstones. It is also possible that the Scremerston and Cementstone Formations of the lower Carboniferous could form a significant hydrocarbon source in the area. TOC (total organic carbon) values of 4-6% have been reported from the area indicating a good potential source rock and a mature kitchen is believed to lie at, and to the south west of, the licence.

Regional burial plots indicate that significant uplift occurred in the Permian, Jurassic and Tertiary. The lower Carboniferous could have been mature and generating gas by Permian times. Deepest burial occurred in the mid Tertiary so subsequent uplift may have arrested gas generation.

In the licence area, there is uncertainty associated with the effectiveness of migration pathways, sufficient gas charge and gas saturations. There is little evidence to prove or disprove if traps are fill to spill point. As the Carboniferous sands were water wet in 41/10-1 (gas shows only) and 42/5-1, there is a risk associated with charge effectiveness at least into the lower Carboniferous intervals. However, charge appears to be effective over the Lytham prospect with gas in the middle Carboniferous and the Zechstein reservoirs.

2.1.3 Traps

The primary trapping style is likely to be faulted dip closures at the Permian and Carboniferous level. There is a pronounced unconformity at the base Permian (BPU) and the underlying Carboniferous is significantly folded due to Hercynian movements. The 41/10-1 well appears to have tested a valid intra Carboniferous dip closure but was not a structure at the base Permian level (**Figure 2.2**). Failure analysis indicates there is a risk of intra Carboniferous seals and/or effective migration pathways into the trap within the local area. Both the 41/5-1 and 41/10-2 wells are believed to have encountered gas pay where valid fault and dip closures have been identified at the base Permian, Zechstein Hauptdolomite and Plattendolomite levels (**Figure 2.3**).

This implies effective regional seals at least above these three reservoirs levels. The size of the traps will depend, in part on the faulting and hence side seals, especially associated with downfaulted traps. Effective seismic time to depth conversion is also critical in this area where lateral velocity changes are significant to define trap size.

The development of traps associated with the carbonates buildup fairway in the northeast of 41/10 is being advanced by CNR. It is possible that such traps are partially stratigraphically enhanced within sweetspots and associated fractured zones within the carbonate build up fairway (**Figure 2.4**). Carbonate build-ups are also indicated on seismic to the east of the licence area, for example, in the northern part of quadrant 42.

Currently less than half of the licence area is covered by 3D seismic. The 3D was acquired in 1993 and has had limited reprocessing. Significant trap potential lies in the remaining areas which may be identified by modern broadband 3D acquisition and reprocessing.

2.2 Previous Drilling

The first well drilled in the licence area was 41/10-1, operated by Marathon in 1994/5 to test the Carboniferous (**Figure 2.2**). It had gas shows, and possibly thin gas pay, in the Zechstein Hauptdolomite and Plattendolomite but the underlying lower Carboniferous (Dinantian) was dry with minor gas shows. An 800 m Carboniferous clastic interval was encountered with locally high net sand intervals. Porosities were reasonable in the upper section, but deteriorated with depth to approximately 5% at 3000 m. Net gas pay of 8 m has been interpreted by Wintershall[9] in the Platten and Hauptdolomites but none of the intervals were tested. A small closure may exist at these levels (**Figure 2.5**).

The blocks (as licence P1129) were awarded to Walter UK (E&P) Ltd in 2003. Walter operated the 41/5-1 well drilled in 2004 into the top 30 m of the Carboniferous (**Figure 2.3**). The well encountered Namurian sandstones but logs were poor without gas shows. The well suffered a near catastrophic failure of the Hauptdolomite reservoir with consequent loss of mud and the damaging of the shallower Plattedolomite reservoir. Gas shows were encountered throughout most of the Hauptdolomite and Plattendolomite on mud logs but the logs were unavailable for inspection and suffered from poor hole conditions. Significant mud losses and gas shows occurred in the Hauptdolomite indicating localised high, porosity and permeability.

The Plattendolomite is believed to have gas pay although it is unclear if gas pay exists in the Hauptdolomite. Both intervals were tested, the Plattendolomite produced some gas without water, but results were ambiguous, partly due to poor hole conditions. According to published maps, a trap may only exist at the Plattendolomite level; the structural closure at the Hauptdolomite is doubtful and no trap was recognized at the Base Permian/Top Carboniferous levels (**Figures 2.5-2.7**).

Lundin farmed in and operated the 41/10-2/2z well in 2007 (**Figures 2.2 and 2.3**). After various changes of ownership, Wintershall became operator in 2008 but relinquished without further drilling. The Lytham prospect was drilled by well 41/10a-2/2z by Lundin Britain Ltd in 2007 to test the Zechstein carbonates (Platten and Hauptdolomites) and the Carboniferous (**Figures 2.5 and 2.6**). The well was sidetracked because of a stuck bottom hole assemblage (BHA). Mudlog gas shows were noted in all three objectives. Wintershall interprets 32 m of Namurian sandstone pay (average porosity 8% and gas saturation 30-40%) but wireline/LWD logs are poor and interpretation is ambiguous (**Figure 2.8**). The Plattendolomite is interpreted to have localised secondary porosity although gas readings were generally low. The Hauptdolomite mudlogs and wireline/LWD logs indicate gas intervals in porous reservoirs although interpretations are uncertain. Wintershall interpret 33 m of reservoir with 7% average porosity and 60% gas saturation (**Figure 2.8**). No tests were made and the data acquired were not sufficient to adequately assess the prospectivity of the Lytham trap.

2.3 Prospective Resources

The resource volumes reported in **Tables 2.1 and 2.2** are gross on licence. CNR currently have a 100% working interest in the licence so the gross and net volumes are identical.[9]

Prospective Resources for the Prospects in Licence P2252 (Bscf)								
Prospect	**Gross on Licence**			**Net Attributable**			**Risk Factor %**	**Operator**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**		
Lytham Permian	12	52	195	12	52	195	51	CNR
Lytham Carboniferous	12	44	149	12	44	149	30	CNR
Fairhaven	**9**	**36**	**125**	**9**	**36**	**125**	26	CNR
Total Gas	**33**	**132**	**479**	**33**	**132**	**479**		

Table 2-1: Prospective Resources in the Prospects in Licence P2252 Gross and Net

[9] **Net Attributable** is net working interest to CNR and is not necessarily the same as net entitlement. Net working interest is that portion of the gross resources attributable to the equity interest owned by CNR. Net entitlement will depend on the contractual terms of the licence at the time of any eventual hydrocarbon production.
Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Prospective resources are the volumes expected to be recovered from UPIIP (undiscovered petroleum initially in place) under conceptual projects, conditional on discovery and development.
Low, Best and High Estimate: in a probabilistic resource size distribution these are the P_{90} (90% probability), P_{50}, and P_{10}, respectively, for individual opportunities.
Risk Factor for prospective resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the prospective resource maturing into a contingent resource. Prospective resources have both an associated chance of discovery (geological chance of success) and a chance of development (economic, regulatory, market and facility, corporate commitment and political risks). The chance of commerciality is the product of these two risk components. These estimates have been risked for chance of discovery but not for chance of development.
Totals do not take account of prospect dependencies and have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.

Prospective Resources for the Leads in Licence P2252 (Bscf)								
Lead	Gross on Licence			Net Attributable			Risk Factor %	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
St Anne's Permian	4	14	52	4	14	52	20	CNR
St Anne's Carboniferous	4	16	58	4	16	58	12	CNR
Total Gas	**8**	**30**	**110**	**8**	**30**	**110**		

Table 2-2: Prospective Resources in the Lead in Licence P2252 Gross and Net
(see Table 2.1 footnotes)

The location of the prospects and leads are shown in **Figure 2.9**. A more detailed description of the individual lead resource and risk assessment is included in the asset description sections of this report (**Sections 2.3.1 to 2.3.3**). The Carboniferous and Zechstein plays are proven in the area. The assigned risks are attributable to the specific prospect and leads especially due to reservoir and seal effectiveness and gas charge. Further detailed seismic interpretation and depth conversion is required to map the prospects accurately, to reduce risk and to upgrade any lead into drillable prospects. It is likely that the resource ranges will be substantially reduced if rigorous mapping and depth conversion confirm the trapping integrity and areal extent of these prospects and leads. Drilling by other operators in neighbouring areas is likely, and further risk reduction will occur if these drilling programmes are successful. Further studies and seismic acquisition, outside the current 3D area in 41/5 and 42/1 by CNR, are likely to result in new potential traps being identified and some may be matured to drillable prospects.

2.3.1 Lytham Prospect

The Lytham prospect lies entirely within block 41/10 and the trap was drilled by the 41/10-2/2z well in 2007 (**Figures 2.5 and 2.6**). The prospect is considered as relatively low risk due to the indications of gas pay in the Permian and top Carboniferous in 41/10-2 although the log quality was poor and hence interpretations ambiguous. The reservoirs are potentially capable to flow economic rates of gas especially if fractured. The trap is assessed for prospective resources as a discovery remains unproven and none of the prospective intervals have been adequately tested with, or without stimulation.

2.3.1.1 Chance of Success

Trap: the structure is mapped on PSTM (pre stack time migration) 3D seismic originally acquired in 1993 by Marathon but subsequently reprocessed. Seismic quality is generally good in the Zechstein although the resolution is not sufficient to map the dolomite intervals accurately; it is poor to very poor in the Carboniferous.

Axis have reviewed the 3D seismic and considers that a viable trap is likely to exist. The trap is defined on the seismic in time at the Zechstein and top Carboniferous levels. Depth maps were available in the Wintershall relinquishment report (2009)[9] which were also published in the TrapOil admission document to AIM (2011)[11]. The core of the structure is well defined and essentially a four-way dip closure but the maximum spill point to the north depends on a downthrown fault seal. Detailed velocity modelling will result in more robust depth maps and constrain the range of areas assigned in the volumetric assessment. It is possible that a large structure also exists deeper within the Carboniferous but this has yet to be mapped by CNR and will require effective intra Carboniferous seals.

Prospect Trap Chance = 90% (Carboniferous), 90% (Permian)

Reservoir: the presence of Carboniferous reservoir in the area is confirmed by 41/10-2z but the well was not tested hence effectiveness and productivity is unproven. The net thickness in the Namurian is poorly constrained and reservoir quality is likely to be fairly low although should be potentially capable of commercial gas rates especially if fractured and overpressured. Deeper lower Carboniferous intervals, as drilled by well 41/10-1, are also potential reservoirs with thick sandstones, although reservoir quality may be poor especially below 3000 m. The Yoredale sandstones are interpreted with over 60 m net sandstone in a number of sandstone intervals with porosities in the range of 6-13%.

The primary Permian reservoirs consist of the Plattendolomite and the underlying Hauptdolomite in the Upper Permian Zechstein. The well results indicate potentially good to very good localised reservoirs, probably associated with secondary porosity, vugs and fracturing. The effectiveness of the reservoir should be proved by testing.

Prospect Reservoir Chance = 60% (Carboniferous), 70% (Permian).

Seal: the Permian Zechstein evaporates are the proven regional seals in the area. It is likely that intraformational seals exist within the Zechstein to seal the Plattendolomite and Hauptdolomite reservoirs.

Intraformational seals in the Carboniferous are also possible but are unlikely near to the top of the Carboniferous section within the prospect area given the relatively high net to gross in the Namurian in well 41/10-2. Seal risk is also associated with leakage along faults especially along the downthrown fault bounding the northern extent of the prospect. Thief zones are also possible, where potential seals along the flanks of the trap are ineffective for gas.

Prospect Seal Chance = 80% (Carboniferous), 90% (Permian).

Charge: a regional source and effective charge is proven by the three wells on the licence and all indicate some gas pay. There is a risk associated with the effectiveness of migration routes, trap fill and gas saturations especially in the Carboniferous. Local charge appears to be effective over the Lytham prospect with gas potentially in the Carboniferous and the Permian reservoirs in 41/10-2z.

Prospect Charge Chance = 80% (Carboniferous), 90% (Permian).

Prospect	Play %	Trap %	Reservoir %	Seal %	Charge %	Chance of Discovery %
Lytham Permian	100	90	70	90	90	51
Lytham Carboniferous	100	90	60	80	70	30

Table 2-3: Lytham, Prospect Risk Assessment

2.3.1.2 Permian Resources

The high case P_{10} area of 23 km^2 is based on the extent of the maximum closing contour at 6300 ft on the Lytham Hauptdolomite depth map (**Figure 2.5**). The low case P_{90} area is 6.6 km^2 at the 6100 ft contour. The range of volumes considers the structural integrity to the spill point together with the fill factor which is linked to effective gas charge.

The reservoir parameters used for the volumetrics (**Table 2.4**) are based on 41/10-2/2z and the wells in the area.

Variability and uncertainty in net pay reservoir thickness away from well control has been accommodated in the resource estimations. Well 41/10-2z encountered 30 m of potential pay in the Hauptdolomite (**Figure 2.8**). In 41/10-1, a pay thickness of 8 m was derived from the petrophysical analysis in the Hauptdolomite (3 m) and Plattendolomite (5 m) and indicates a low case.[9] In well 42/9-1, 20 m of pay is indicated from the Hauptdolomite. The high case net pay of 90 m is derived from a log normal distribution and assumes high net to gross in both Hauptdolomite and Plattendolomite reservoirs. The range between the low and high cases is relatively high at over 9 to 1, indicating the significant uncertainty in the development and distribution of reservoir and pay thickness over the prospect area.

In the well, the porosity of the dolomites is typically 7%, although this may be significantly enhanced locally by fracturing and vuggy porosity. The low and high cases were 4 and 11% derived from a normal distribution. The parameters used consider the lower porosity of the relatively tight matrix and enhancement due to facies, diagenetic effects, fracturing and vugs.

The water saturation is based on the Hauptdolomite logs in 41/10-2 and the gas expansion factor was calculated from the ranges of temperature and burial depth. The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS. The Wissey Zechstein field in 53/4 is reported to have an estimated recovery of 65%[12]; the Zechstein in the Hewett field is 50% but approaching 80% may be achieved in better quality reservoir.[8]

Lytham Upper Permian Volumetric Input Parameters			
	Low	**Best**	**High**
Net Pay Thickness (m)	10	30	90
Porosity (%)	4	7	11
Gas Saturation (%)	45	55	65
Formation Volume Factor (Gas)	180	190	200
Gas Recovery Factor (%)	40	60	80

Table 2-4: Lytham Upper Permian Prospect, Volumetric Input Parameters

The volumetric parameters for the Lytham prospect were input into the REP stochastic software and in place and prospective resources were calculated. The total unrisked mean UPIIP is 144 Bscf gross of gas on licence and the mean prospective resources are 85 Bscf gross.

Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 2.5**).

Gas Initially in Place (GIIP) (Bscf)								
Lytham Prospect	**Gross on Licence**				**Net on Licence**			
	Low estimate	**Best Estimate**	**High Estimate**	**Mean Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**Mean Estimate**
Permian	23	91	326	144	23	91	326	144

Prospective Resources (Bscf)						
Lytham Prospect	**Gross on Licence**			**Net Attributable**		
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**
Permian	**12**	**52**	**195**	**12**	**52**	**195**

Table 2-5: Lytham Upper Permian Prospect, GIIP[10] and Prospective Resources - Gross and Net

[10] The mean GIIP has been added for completeness.

The ratio of the high to low cases is large reflecting the significant uncertainties with the current dataset.

2.3.1.3 Carboniferous Resources

The high case P_{10} area of 21 km^2 is based on the extent of the maximum closing contour at 6500 ft on the Carboniferous depth map (**Figure 2.6**). The minimum P_{90} area is 6 km^2 at the 6300 ft contour. The range of volumes considers the structural integrity to the spill point together with the fill factor which is linked to effective gas charge.

The reservoir parameters used for the volumetrics (**Table 2.6**) are based on 41/10-2/2z and the wells in the area.

Variability and uncertainty in net pay reservoir thickness away from well control has been accommodated in the resource estimations. The best case net pay thickness of 25 m was derived from the petrophysical analysis of the 41/10-2z well log data in the Namurian. Only 100 m of Namurian section was drilled so it is likely that effective reservoirs extend below the well depth. The high case assumes an average gross thickness of 60 m across the trap with a high net to gross and the possibility of stacked reservoirs. The maximum structural relief is of the order of 100 m. The assigned value for the low case net pay is 10 m derived from a log normal distribution. The range between the low and high cases is high at 9 to 1, indicating the uncertainty in the development and distribution of reservoir and pay thickness over the prospect area.

In the well 41/10-2z, the porosity of the Namurian sandstones is typically 8%, although this may be enhanced by fracturing. The low and high cases were 4 and 12% derived from a normal distribution to account for the ranges seen in the well and additional regional data. The parameters consider the lower porosity of the relatively tight matrix porosity and enhancement due to facies, diagenetic effects and fracturing.

The water saturation is based on that found in the Namurian in 41/10-2z and analogous reservoirs. The gas saturations were low in the well based on the Wintershall interpretation but are considered unreliable due to the poor quality of the LWD logs (**Figure 2.8**). This risk has also been considered in the charge chance of success. The gas expansion factor was calculated from the ranges of temperature and burial depth. The range of gas recoveries have a wide range due to the uncertainty of reservoir quality but are consistent with those normally expected in analogous quality reservoirs. In the Breagh field it has been reported to be of the order of 60%.

Lytham Carboniferous Volumetric Input Parameters			
	Low	Best	High
Net Pay Thickness (m)	10	25	60
Porosity (%)	4	8	12
Gas Saturation (%)	45	55	65
Formation Volume Factor (Gas)	190	200	210
Gas Recovery Factor (%)	40	60	80

Table 2-6: Lytham Carboniferous Prospect, Volumetric Input Parameters

The total unrisked mean UPIIP is 114 Bscf gross of gas on licence and the mean prospective resources are 67 Bscf gross.

Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 2.7**).

Gas Initially in Place (GIIP) (Bscf)								
Lytham Prospect	Gross on Licence				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Carboniferous	22	78	249	114	22	78	249	114

Prospective Resources (Bscf)						
Lytham Prospect	Gross on Licence			Net Attributable		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Carboniferous	12	44	149	12	44	149

Table 2-7: Lytham Carboniferous Prospect, GIIP[11] and Prospective Resources - Gross and Net

[11] The mean GIIP has been added for completeness.

The ratio of the high to low cases is large and is approaching fifteen reflecting the significant uncertainties with the current dataset.

2.4.1 Fairhaven Prospect

The Fairhaven prospect lies mainly within block 41/5 and the trap was drilled by the 41/5-1 well in 2004. Gas shows were recorded from a number of prospective horizons and the wireline logs, although of poor quality, indicate gas pay is probably present in the Permian Hauptdolomite and in the Plattendolomite. The Hauptdolomite flowed water but the test was considered invalid due to no isolation. The Plattendolomite produced some gas with no water. The trap is considered for prospective resources as tests and wireline logs were unsatisfactory due to hole conditions and hence a discovery remains unproven.

The prospect is considered as relatively low risk due to the indications of pay in the Permian in 41/5-1 although the log quality was poor and interpretations ambiguous. The reservoirs are potentially capable to flow economic rates of gas especially if fractured.

2.4.1.1 Chance of Success

Trap: the structure is mapped on PSTM (pre stack time migration) 3D seismic, originally acquired in 1993 by Marathon but subsequently reprocessed. Seismic quality is generally good in the Zechstein although the resolution is not sufficient to map the dolomite intervals accurately; it is poor to very poor in the Carboniferous.

The trap is indicated at the Zechstein (Plattendolomite) level by maps published in the TrapOil admission document to AIM (2011) (Figure 2.7). The western edge of the prospect is mapped from 2D data where 3D does not exist. The area is also partially covered by the depth maps in the Wintershall report at both the Hauptdolomite and Namurian levels based on the 3D seismic (Figures 2.6 and 2.7). The core of the structure appears relatively robust at the Plattendolomite level on 3D seismic and essentially is a four-way dip closure. The southern margin is crossed by two E-W trending faults (Figure 2.10). However, the TrapOil depth map does not indicate any faults which are clear on the seismic and Wintershall maps (Figures 2.5-2.7). Detailed horizon mapping is required to validate closure in time, and velocity modelling will result in more robust depth maps, mitigate risk and constrain the range of areas assigned in the volumetric assessment. It is possible that a structure also exists within the Carboniferous but this has yet to be mapped by CNR and will require effective intra Carboniferous seals. Axis have reviewed the 3D seismic and considers that a viable trap is likely to exist. However, the seismic database available could not confirm a westerly time closure. Only the Permian has been assessed for prospective resources.

Prospect Trap Chance = 60% (Permian)

Reservoir: The primary Permian reservoirs consist of the Plattendolomite and the underlying Hauptdolomite in the Upper Permian Zechstein. The well results indicate potentially good to very good localised reservoirs probably associated with secondary porosity, vugs and fracturing. The wireline logs were unreliable and test results in the 41/5-1 well were ambiguous. The effectiveness of the reservoir may be proved by adequate testing although it is likely that reservoir potential is very variable and will be dependent on fractures, sweet spots and a well bore oriented to effectively transect the fractures.

Prospect Reservoir Chance = 60% (Permian)

Seal: the Permian Zechstein evaporates are the proven regional seals in the area. It is likely that intraformational seals exist within the Zechstein to seal the Plattendolomite and Hauptdolomite reservoirs. Seal risk is also associated with leakage along faults especially bounding the southern edge of the prospect.

Prospect Seal Chance = 90% (Permian)

Charge: a regional source and effective charge is proven by the three wells on the licence and all indicate some gas pay. There is a risk associated with the effectiveness of migration routes, trap fill and gas saturations. Local charge appears to be effective over the Fairhaven prospect with gas potentially in the Permian reservoirs in 41/5-1.

Prospect Charge Chance = 80% (Permian)

Prospect	Play %	Trap %	Reservoir %	Seal %	Charge %	Chance of Discovery %
Fairhaven Permian	100	60	60	90	80	26

Table 2-8: Fairhaven, Prospect Risk Assessment

2.4.1.2 Permian Resources

The high case P_{10} area of 27 km^2 is based on the extent of the maximum closing contour at 4450 ft on the Fairhaven Plattendolomite depth map (**Figure 2.7**). Only the P2252 licence area has been considered in the volumes although the trap may extent marginally outside the licence area in the high case. The low case P_{90} area is 6.5 km^2 at the 4250 ft contour which approximates to the edge of the 3D data and the area updip of the 42/5-1 well.

The reservoir parameters used for the volumetrics (**Table 2.9**) are based on 41/5-1 and the wells in the area.

Variability and uncertainty in net pay reservoir thickness away from well control has been accommodated in the resource estimations. Well 41/10-2 encountered 30 m of potential pay in the Hauptdolomite. In 41/10-1, a pay thickness of 8 m was derived from the petrophysical analysis in the Hauptdolomite (3 m) and Plattendolomite (5 m) and indicates a low case. The logs for 41/5-1 were inconclusive, but pay is believed to be in the Plattendolomite and Hauptdolomite within the assigned ranges. The net pay thickness for the best and high cases are considered to be less than in the Lytham prospect as the structural relief and therefore possible hydrocarbon column is reduced. Also, there is considerable uncertainty if trap or gas pay exists in the Hauptdolomite in 41/5-1. The high case net pay of 60 m is derived from a log normal distribution. The range between the low and high cases is relatively high at over 6 to 1, indicating the significant uncertainty in the development and distribution of reservoir and pay thickness over the prospect area.

No reliable porosity data was available from the 41/5-1 well. The porosity range applied is the same as for the Lytham prospect based on 41/10-2. The water saturation is based on the Plattendolomite logs and analogous data and the gas expansion factor was calculated from the ranges of temperature and burial depth. Gas may be in the Plattendolomite and / or the deeper Hauptdolomite. The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS.

Fairhaven Upper Permian Volumetric Input Parameters			
	Low	Best	High
Net Pay Thickness (m)	10	25	60
Porosity (%)	4	7	11
Gas Saturation (%)	45	55	65
Formation Volume Factor (Gas)	140	150	160
Gas Recovery Factor (%)	40	60	80

Table 2-9: Fairhaven Upper Permian Prospect, Volumetric Input Parameters

The volumetric parameters for the Fairhaven prospect were input into the REP stochastic software and in place and prospective resources were calculated. The total unrisked mean UPIIP is 95 Bscf gross of gas on licence and the mean prospective resources are 56 Bscf gross.

Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 2.10).**

Gas Initially in Place (GIIP) (Bscf)								
Fairhaven Prospect	Gross on Licence				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Permian	18	64	210	95	18	64	210	95

Prospective Resources (Bscf)						
Fairhaven Prospect	Gross on Licence			Net Attributable		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Permian	9	36	125	9	36	125

Table 2-10: Fairhaven Upper Permian Prospect, GIIP[12] and Prospective Resources - Gross and Net

The ratio of the high to low cases is large and is of the order of fourteen reflecting the significant uncertainties with the current dataset.

[12] The mean GIIP has been added for completeness.

2.4.2 St. Anne's Lead

The lead has been identified in the TrapOil AIM Admission Document[11] and independently evaluated by Challenge Energy.[11] The trap is an undrilled structure lying to the east of the Lytham prospect and mapped from the 3D PSTM volume. A depth map and seismic near to the Hauptdolomite reservoir level (**Figures 2.11 and 12**) indicates the trap is a four-way dip closure; the greater part of the structure is in 42/10 but is likely to extend into 41/5. The St Anne's lead is also identified from the Wintershall maps at the Namurian and Hauptdolomite levels but are substantially smaller (**Figures 2.5 and 2.6**). Further seismic interpretation and depth conversion is required to mitigate risk and constrain trap size before this potential trap could be considered a drillable prospect.

2.4.2.1 Chance of Success

Trap: depth maps by Trap and Wintershall recognizes the St Anne's feature at the Hauptdolomite and Base Permian Unconformity levels. The Trap mapping indicates a relatively large four-way dip closure; the Wintershall mapping divides the area into two small closures. A small closure is also identified at the Base Zechstein / top Carboniferous level.

Axis have reviewed the 3D seismic which indicates that a Zechstein time closure is likely to exist. It is also possible that a larger intra Carboniferous trap exists, on trend to the high tested by 41/10-1. In addition, potential subcropping intra Carboniferous seals may enhance sealing geometries and trap size at the top Carboniferous. This current evaluation is based on the map in the TrapOil prospectus but considers the significant range of trap sizes based on available maps and the additional risks. The Zechstein interval indicates significant facies changes and hence lateral velocity changes will impact trap size. CNR detailed mapping and depth conversion is in progress to constrain the range of trap area and to mitigate risk.

Prospect Trap Chance = 60% (Carboniferous), 60% (Permian).

Reservoir: it is likely that the Namurian, as encountered in 41/10-2z, would be absent and the subcropping Carboniferous would be the Lower Carboniferous section as drilled in 41/10-1. It is likely that this interval will consist of a number of stacked sand and shale intervals. Well 41/10-1 encountered thick sandstones in the lower Carboniferous Yoredale, Scremerston and Fell sandstone formations. The Yoredale sandstones are interpreted with over 60 m net sandstone in a number of sandstone intervals with porosities in the range of 6-13%.

Deeper Carboniferous intervals are also potential reservoirs with the potential of thick sandstones although reservoir quality may be poor at depths below 3000 m.

Thick sandstones also exist in the Fell Sandstone Formation but reservoir is expected to be very low at the objective depths.

The primary Permian reservoirs consist of the Plattendolomite and the underlying Hauptdolomite in the Upper Permian Zechstein. The well results in blocks 41/5 and 41/10 indicate potentially good to very good localised reservoirs probably associated with secondary porosity, vugs and fracturing although the effectiveness of the reservoir has not been proved by testing.

Lead Reservoir Chance = 50% (Carboniferous), 60% (Permian).

Seal: the Permian Zechstein evaporates are the proven regional seals in the area and will be effective to seal any top Carboniferous reservoirs. It is likely that intraformational seals exist within the Zechstein to seal the Plattendolomite and Hauptdolomite reservoirs. Intraformational seals in the Carboniferous are also possible within the lower Carboniferous section drilled by well 41/10-1 but are considered high risk.

Lead Seal Chance = 80% (Carboniferous), 80% (Permian).

Charge: a regional source and effective charge is proven in the area. There is risk associated with the effectiveness of migration routes and gas saturations especially for the Carboniferous. The source is believed to be Westphalian coal rich intervals in the upper Carboniferous Westphalian or possibly the deeper coals in the middle and lower Carboniferous. The former requires long distant migration which would be difficult especially into the older Middle and Lower Carboniferous sandstones which subcrop the Permian within the structure. It is possible that the Lower Carboniferous Scremerston Formation is the primary source in the area for the Lower Carboniferous interval. There is little evidence to prove or disprove that structures in the area are fill to spill point and this uncertainty is considered in the volumetrics. As the trap lies along strike to 41/5-1, and the Carboniferous sands were water wet in 41/10-1 and 42/5-1, there is significant risk associated with sufficient generated volumes and / or charge effectiveness. The risk is less for the Permian as all wells drilled on the licence indicated effective migration routes.

Lead Charge Chance = 50% (Carboniferous), 70% (Permian).

Lead	Play %	Trap %	Reservoir %	Seal %	Charge %	Chance of Discovery %
St Anne's Permian	100	60	60	80	70	20
St Anne's Carboniferous	100	60	50	80	50	12

Table 2-11: St Anne's Lead, Risk Assessment

2.4.2.2 Permian Resources

For the purposes of this evaluation, Axis have based the volumetrics on the base Permian Unconformity depth map in the TrapOil report, which may be considered as a proxy to the Hauptdolomite structure. A wide range of area has been considered to account for the uncertainties of mapping and in depth conversion. No maps of the Plattendolomite were available. The high case P_{10} area of 8 km^2 is based on the extent of the maximum closing contour at 6250 ft on the St Anne's depth map (**Figure 2.11**). The low case P_{90} area is 2 km^2 at the 6100 ft contour. The depth maps in the Wintershall report indicate smaller closed area than that in the TrapOil report consistent with the low case area.

The reservoir parameters used for the volumetrics (**Table 2.12**) are based on the wells in the area as described in **Sections 2.3.1.2 and. 2.3.2.2**. The net pay thickness has been reduced compared to the Lytham trap due to the lower relief of the structure.

St Anne's Upper Permian Volumetric Input Parameters			
	Low	Best	High
Net Pay Thickness (m)	10	25	60
Porosity (%)	4	7	11
Gas Saturation (%)	45	55	65
Formation Volume Factor (Gas)	180	190	200
Gas Recovery Factor (%)	40	60	80

Table 2-12: St Anne's Upper Permian Lead, Volumetric Input Parameters

The volumetric parameters for the St Anne's lead were input into the REP stochastic software and in place and prospective resources were calculated. The mean UPIIP is 39 Bscf gross of gas on licence and the mean prospective resources are 23 Bscf gross

Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 2.13**).

Gas Initially in Place (GIIP) (Bscf)								
St Anne's Lead	Gross on Licence				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Permian	7	25	86	39	7	25	86	39

Prospective Resources (Bscf)						
St Anne's Lead	Gross on Licence			Net Attributable		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Permian	4	14	52	4	14	52

Table 2-13: St Anne's Upper Permian Lead, GIIP[13] and Prospective Resources - Gross and Net

The ratio of the high to low cases is large and is of the order of fifteen reflecting the significant uncertainties with the current datasets.

2.4.2.3 Carboniferous Resources

Carboniferous Resources

For the purposes of this evaluation, Axis have based the volumetrics on the top Carboniferous or Base Permian Unconformity depth map in the Trap Oil report (**Figure 2.11**). The Wintershall Top Carboniferous map indicates two small separate dip closures. A wide area range been applied to account for the uncertainties of mapping and in depth conversion as for the Zechstein reservoirs. The high case P_{10} area of 8 km^2 is based on the extent of the maximum closing contour at 6250 ft on the St Anne's depth map (**Figure 2.11**). The low case P_{90} area is 2 km^2 at the 6100 ft contour.

The reservoir parameters used for the volumetrics (**Table 2.14**) are based on the wells in the area as described in **Section 2.3.1.3**. The net pay has been reduced compared to the Lytham trap because of the lower relief of the structure.

[13] The mean GIIP has been added for completeness.

St Anne's Carboniferous Volumetric Input Parameters			
	Low	Best	High
Net Pay Thickness (m)	10	25	60
Porosity (%)	4	8	12
Gas Saturation (%)	45	55	65
Formation Volume Factor (Gas)	190	200	210
Gas Recovery Factor (%)	40	60	80

Table 2-14: St Anne's Carboniferous Lead, Volumetric Input Parameters

The total unrisked mean UPIIP is 44 Bscf gross of gas on licence and the mean prospective resources are 26 Bscf gross.

Low (P**90**), Best (P**50)** and High (P**10**) and mean gas in place and prospective resources are tabulated below (**Table 2.15**).

Gas Initially in Place (GIIP) (Bscf)								
St Anne's Lead	Gross on Licence				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Carboniferous	8	28	97	44	8	28	97	44

Prospective Resources (Bscf)						
St Anne's Lead	Gross on Licence			Net Attributable		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Carboniferous	4	16	58	4	16	58

Table 2-15: St Anne's Carboniferous Lead Prospect, GIIP[14] and Prospective Resources - Gross and Net

The ratio of the high to low cases is large and is of the order of fifteen reflecting the significant uncertainties with the current dataset.

2.5 Additional Potential

Currently less than half of the licence area is covered by 3D seismic which was acquired in 1993 and has had limited reprocessing. The two prospects and one lead identified for prospective resources lie within the area of 3-D coverage over most of block 42/10 and the southern edge of 41/5.

[14] The mean GIIP has been added for completeness.

Most of the licence is only covered by old 2D seismic data and only a loose regional grid has been acquired by CNR. Significant trap potential, especially in the Permian Zechstein and Carboniferous, lies in the licence which may be identified by modern 3D acquisition and reprocessing. A more recent multi-client 3D survey completed by Polarcus in 2014 covers the eastern most block 42/1 and may shed new light on the prospectivity of this area should it become available.

The area is sensitive to depth conversion; detailed velocity modelling is required to accurately assess the presence and size of the traps. Some traps may be absent or poorly defined on the time maps and have hence been missed by the earlier periods of exploration when velocity modelling was less developed. Trap size may also be significantly enhanced by sealing faults.

The exploration of the Zechstein has been neglected in UKCS. The interval has often been historically considered as a drilling hazard with overpressured zones and potential reservoirs damaged by over balanced drilling resulting in poor wireline log quality. Hence reliable log interpretation and tests has been problematic, discouraging further exploration.

Within the UKCS, the nearest Zechstein production is from the Hewett field in 48/29 and 48/30 area. Zechstein production has occurred from 1986.[8] Conoco's 41/24a-2z horizontal well tested 100 MMscfd from Zechstein. In addition, several Zechstein fields for oil and gas occur onshore and offshore the Netherlands as well as commercial fields onshore U.K. in the Vale of Pickering that are generating recent interest.

In Hewett, fracture prediction was critical for optimum reservoir development. However, some fracture zones contribute little to gas production. Apparently, those intervals with high uranium, deposited along significant conduits, are key producing intervals. The high production is believed to be caused by clay laminae, susceptible to acid fraccing. Also apparently, high productivity is commonly from lower porosity intervals with high apparent water saturations.[8]

There is evidence that Zechstein carbonate build-ups locally exist and should be mappable on modern 3D seismic within the CNR licence area. The development of traps associated with a carbonates buildup fairway in the northeast of 41/10 is being advanced by CNR.

Seismic analysis indicates potential thick areas of Zechstein are developed within the licence area and are interpreted to be associated with carbonate buildups lying between the shelfal and basinal facies (**Figure 2.4**). It is possible that such traps are partially stratigraphically enhanced with reservoir sweetspots and associated fractured zones within the carbonate build up fairway. This facies belt has not yet been tested on the licence and has been inadequately explored in the area.[13]

It is believed that this play has been successively pursued in the Netherlands for example by Shell and in Palaeozoic carbonate plays in other basins in the world. In the Netherlands, NAM have discovered gas reserves in excess of 2 Tscf from the Zechstein Z2 (Hauptdolomite) interval.[15] 3D seismic is required to define facies and quantitative analysis to predict porosity. Fracture studies are key to optimise drilling patterns and productivity. Some of the best reservoirs occur along the steep platform edge associated with zones of high fracture density on the windward side or eastern edge of the basin. A similar setting can be identified in the P2252 licence area. Prospects associated with this play are currently being developed by CNR and so are not reported here as prospective resources. The potential of this play according to CNR is discussed in **Appendix 5**.

The effectiveness of the reservoir have not yet been adequately proven by testing within the licence. Petrophysical analysis of the Zechstein has been historically problematic and reservoir potential may be underestimated especially in fractured areas. Commonly, zones with poor porosity may have enhanced fracture permeability due to the brittle nature of the relatively tight and massive carbonates. The exploration of the Zechstein carbonates require good high resolution seismic, together with core and wireline image based fracture and facies studies to predict reservoir sweet spots. Optimum drilling conditions through the Zechstein, including underbalanced drilling, are required to ensure reliable evaluation of wireline, test and core data.

The Carboniferous play has been inadequately explored in the licence area. Recent development of the Breagh field (42/13) and several nearby discoveries including Crosgan (42/10), Pegasus (43/13) and Pegasus West have helped to derisk the Carboniferous play in the area. The gas is at the top of the Carboniferous but middle and lower Carboniferous sandstones have been proven to exist and to be effective reservoirs enabling production at economic rates through effective drilling and completion strategies. Intra Carboniferous seals are also proven to be locally effective as in Pegasus so stratigraphic traps may exist with Carboniferous seals subcropping the regional Zechstein seal.

Enhanced production techniques, including deviated and horizontal drilling, may allow gas to be economically exploited from the relatively tight Zechstein and Carboniferous reservoirs in P2252. Production optimisation techniques are discussed in **Section 8**.

3.0 LICENCE P2253

3.1 Geological Setting

Licence P2253 consists of block 42/14b which lies within the northwestern area of the UK Southern North Sea (SNS) basin (**Figure 1.1**). Several fields and discoveries occur in the area and many other wells have indications of gas pay or shows. The primary reservoirs are believed to be in the Carboniferous (Namurian and Dinantian) (**Figure 1.2).** The Upper Permian (Zechstein) may also be prospective and several wells encountered gas shows. The Lower Permian (Rotliegendes) sandstones are not expected to be present but the pinch out line is predicted close to the southern margin of 42/14 so local developed is possible in the south of the block. The Triassic (Bunter play) also exists on the block; a Bunter test on the block (42/14-1) was unsuccessful although there is a minor Triassic discovery in 42/15b-1 (circa 20 Bscf).

The Breagh field (42/12 and 42/13) lies directly to the west with gas reserves believed to be in the order of 700 Bscf in lower Carboniferous (Dinantian) sandstones and the Crosgan discovery (42/10) lies 5 km to the northeast with gas resources circa 100 Bscf (**Figure 3.1**). Recent discoveries have been Pegasus and Pegasus West in 43/13b which have proved that the Namurian is an effective reservoir, capable of high flow rates and trapped by intra Carboniferous seals. This stratigraphic play has been underexplored in the area. A number of large Carboniferous gas fields lie further to the east in quadrants 43 and 44 (e.g. Murdoch, Caister) and several small Carboniferous oil and gas fields lie onshore in eastern England (e.g. Welton, Beckingham, Eakring, Gainsborough).

Zechstein reservoirs, with interpreted gas pay or gas shows, were encountered in the area including wells in CNR licence P2252 and several wells to the west of the licence. The best recorded flow rates were from Conoco’s 41/24a-1 and 41/25a-1 which tested gas from the Plattendolomite. Conoco 41/24a-2z was a horizontal well and is believed to have tested gas at circa 100 MMscfd. Well 42/9-1 and 42/18-2, 10 km to the north, also encountered gas pay in the Hauptdolomite. The Hewett field, with production from the Zechstein Hauptdolomite, lies 50 km to the south.

3.1.1 Reservoir

The primary play on block 42/14b is within the middle and lower Carboniferous reservoirs. The play is confirmed by the Breagh and Crosgan fields which lie in adjacent blocks in 42/13 and 42/10. The reservoir in Breagh is primarily in the Dinantian, Yoredale sandstones (**Figure 3.2**). In Crosgan, gas is believed to be in the Dinantian Yoredale and underlying Whitby sandstones with both intervals subcropping below the Base Permian unconformity.

Within 42/14b, the middle Carboniferous (Namurian) is likely to subcrop the Base Permian Unconformity (BPU) over most of the block; it may be truncated on the highs analogous to the Breagh and Crosgan fields where the Dinantian is the reservoir below the BPU (**Figure 3.3**).

The Namurian interval consists of a number of stacked sand and shale intervals with potential intra Carboniferous seals. Several Namurian fields occur to the east of the licence in quadrant 43 such as Trent (43/24), Kilmar (43/22) and Garrow (43/21) (**Figure 1.1**). The recent discoveries in 43/13b, Pegasus and Pegasus West have proved that the Namurian is effective in the area.

Dinantian reservoirs are also anticipated on the block. In addition to the Breagh and Crosgan fields, several other wells in the area (42/15a-2, 42/18-2, 43/6-1) encountered some Carboniferous gas within potentially effective reservoirs in the upper part of the Dinantian. Thick sandstones also exist in the Fell Sandstone Formation but reservoir is expected to be very low at the objective depths. The Fell is likely to be more prospective to the north of the licence area and good Fell sandstones were encountered in wells 41/01-1, 43/02-1 and 43/05-1 where the interval is shallower and in a more proximal facies.

The lower Permian (Rotliegendes) is generally absent in the area although isolated sandstones are possible especially in the south of the block where a speculative pinchout play may exist.

The primary reservoirs in the upper Permian consist of the Hauptdolomite in the Zechstein. Well 42/9-1, 10 km to the north, encountered circa 20 m of possible gas pay in the Hauptdolomite. Gas was tested from the Hauptdolomite in the 42/15b-1 well at 7.6 MMscf/d and Premier estimate a GIIP of 13-42 Bscf.[15] However, the Zechstein is generally not so well developed to the south and compared to the P2252 area, and wells (e.g.42/18-2) indicate thin carbonates and very low porosity.

The Triassic Bunter sandstones form thick effective reservoirs as in the now depleted Esmond and Forbes fields. In the 42/15 b-1 discovery gas resources are estimated between 10-25 Bscf with porosity 10-23% (most likely 16%) with a high net to gross of 90% (**Figures 3.4 and 3.5**).[15] However, the Bunter is not considered as a primary play due to migration risk and the lack of any significant undrilled structures in the area.

3.1.2 Charge

A regional source for gas and effective charge is proven in the area. The source for the gas is believed to be coal rich intervals in the Carboniferous either from the coal measures of the Westphalian (upper Carboniferous) or the deeper coals in the middle and lower Carboniferous.

Secondary sources may include the Zechstein marine shales and marine bands in the Namurian and coals in the Dinantian Scremerston Formation (**Figure 1.2**). The Westphalian is absent in the area by erosion (**Figure 3.3**) so gas charge from the upper Carboniferous requires long distant migration which may be problematic especially into the older middle and lower Carboniferous sandstones. In the Breagh and Crosgan fields, the gas is directly below the Base Permian Unconformity so charge could be from the Westphalian coals which are present to the south east; migration would be updip below the regional seal at the unconformity. The Namurian and Dinantian source rocks are mature to the south west. The gas is methane rich although some inerts and hydrogen sulphide are present especially in the Triassic and Zechstein reservoirs.

Regional burial plots indicate that significant uplift occurred in the Permian, Jurassic and Tertiary. The deepest burial will have occurred in the mid Tertiary so subsequent uplift may have arrested gas generation. The main period of generation in the area would be from the late Mesozoic. Generation will still be occurring to the southeast towards the basin depocentre.

In the licence area, there is a risk associated with the effectiveness of local migration pathways, sufficient gas charge and gas saturations. There is little evidence to prove or disprove if traps are fill to spill point although the significant gas accumulations at Breagh and Crosgan indicate effective charge over a large area. Both these fields lie along structural highs that would be a focus for regional migration.

3.1.3 Traps

Block 42/14b lies between the northwest-southeast trending Breagh and Crosgan Highs. Axis has reviewed the seismic and legacy structure maps in the area in the CNR data base but the 3D seismic only extends along the eastern part of the block. The nearby Breagh field is a well-defined faulted dip structure at the level of the Base Permian Unconformity. The trap at Crosgan is believed to also be a closure at the BPU with the Zechstein acting as a seal to the subcropping Dinantian reservoirs.

The legacy structure maps available on 42/14b do not show any significant closures exist on the block at the BPU level. However, as the Carboniferous subcrops the BPU, there is excellent potential for traps requiring a combination of Base Permian and intra Carboniferous seals and faults (**Figures 3.5 and 3.6**). Such traps have not been historically identified in the 42/14 area but have recently proved to be viable, for example in the nearby Pegasus and Pegasus West (43/13b) discoveries. Intra Westphalian seals are also effective to the west in many fields onshore the U.K. including the Saltfleetby field, onshore Lincolnshire.

The Saltfleetby field, with reported ultimate reserves of 80 Bscf, is a good example of a basal Westphalian A seal in mudstone dominated coal measures 200 m thick.[10] This play is underexplored in quadrant 42 and has not been historically mapped in detail, partly due to the poor quality of legacy seismic within the Carboniferous and, because of the perceived risks associated with Carboniferous seals.

A well-defined dip closure at the Triassic (Bunter) level exists on the block. The trap was unsuccessfully drilled by an old well 42/14-1 (**Figure 3.5**) although it was not a crestal test on the Triassic maps available. It is unlikely that any significant Bunter potential remains on block.

3.2 Previous Drilling

42/14-1 was drilled as a shallow Triassic test close to the southern edge of the block. Legacy maps at the top Bunter level indicate that the well was drilled on a well-defined four way associated with an underlying Zechstein salt pillow. Objective depth was approximately 1000 m. The well may have been drilled approximately 40 m down dip from the crest but this should be verified by mapping and depth conversion by CNR. No gas pay was reported and it is likely that failure was due to the lack of effective migration paths through the Zechstein salt. A separate small culmination lies to the northwest.

A second well 42/14-2, was drilled on the block in 2010 by RWE DEA. CNR have no information on the well but Stirling Resources announced in 2010 that the well was drilled on the Macanta prospect, a satellite location approximately 13 km east of the main Breagh field. The well encountered wet sands at a deeper level than anticipated and was deemed non commercial and was plugged and abandoned.

42/15b-1 was a small Bunter discovery, drilled 5 km to the east of 42/14b. Good quality Bunter sands tested at 19.6 MMscf/d. It was drilled on a well-defined dip closure above a Zechstein salt pillow. There is an amplitude anomaly at the crest of the structure (**Figure 3.4**). Premier, the previous operator, estimate resources in the range of 10 to 25 Bscf. The gas comprises 80% methane and 20% nitrogen.[15]

The lower Carboniferous Crosgan discovery straddles blocks 42/10b and 42/15b and may extend into 42/14a. The Crosgan discovery was drilled by wells 42/10b-2 & 2z and 42/15a-2.

Well 42/15a-2 also tested from the Hauptdolomite at a low rate of 7.6 MMcf/d post acidization. Premier estimate GIIP in the range of 17-41 Bscf.[15]

The Crosgan appraisal well 42/15b-3, drilled in 2015, encountered circa 10 m of pay in the Whitby Sandstone and a further 8 m in shallower Carboniferous sands. The Whitby formation was encountered 80 m deep to prognosis.

The lower Carboniferous Breagh field lies to the west in block 42/12a and 42/13a. First gas was in October 2013. The GIIP is estimated to be in the range of 300-1900 Bscf. Current production is circa 125 MMscf/d of sales gas.

42/13-1 lies at the 42/14b block boundary and encountered minor gas shows in the Plattendolomite but there were no tests It is believed that a 100 m of Dinantian section was encountered but without any effective reservoirs. It is doubtful if the well was drilled on a valid closure at the BPU. The Breagh field lies updip to the west.

3.3 Prospective Resources

The Carboniferous play is currently unproven within block 42/14b although it is proven in the area for example in the Breagh and Crosgan fields. The evaluation of the block by CNR is at an initial stage and no prospects and leads have currently been identified that may be evaluated for prospective resources at the prospect or lead level. However, the Carboniferous play is considered very prospective on the block and Axis have therefore assessed the potential at the play level as defined by PRMS guidelines (**Figure APP1-2, Appendix 2.2**). Potential also exists in the Permian (Zechstein and Rotliegendes) and Triassic but these are considered less prospective, high risk and have not been considered further for prospective resources.

The assigned risks are attributable at the play level and indicate the chance that the Carboniferous play is viable on block. The play chance of success considers reservoir, seal and gas charge. Further seismic acquisition and reprocessing by CNR will likely result in potential traps being identified and some may be matured to drillable prospects. Detailed seismic interpretation and depth conversion is required to identify traps accurately, constrain volumetrics and to reduce risk. Drilling by other operators in neighbouring areas is likely, leading to further risk reduction if these drilling programmes are successful.

3.3.1 Carboniferous Play

3.3.1.1 Chance of Success

Reservoir: the presence of Carboniferous reservoir in the area is confirmed by the Breagh and Crosgan discoveries. In these fields, the Namurian, middle Carboniferous is absent so the gas pay is in the underlying Dinantian, lower Carboniferous sequence. The Dinantian reservoirs are anticipated to be present throughout the block. In the Breagh field the pay section consists of stacked sandstones and shales, with a high net to gross, deposited as channels and sheet sandstones in a deltaic facies (**Figure 3.7**).

The best Dinantian reservoir may be the Whitby sandstone that subcrops at Crosgan and are likely to be present over most of block. The underlying Scremerston sandstone is also prospective and proven in Breagh. Core poroperm plots are shown in **Figures 3.8 and 3.9**. The Yoredale Group, drilled by 41/10-1, are interpreted to have over 60 m net sandstone in a number of sandstone intervals with porosities in the range of 6-13%. Deeper, lower Carboniferous intervals, as drilled by well 41/10-1, are also potential reservoirs with potential of thick sandstones although reservoir quality may be poor below 3000 m.

The Namurian was tested by the recent Pegasus (43/13b-6) and Pegasus West wells (43/13b-7), 40 km to the east. The best rates were from Pegasus West which tested at a combined rate of 91 MMcf/d from three Carboniferous intervals. In 42/14b, the Namurian is predicted to be subcropping the Base Permian Unconformity. It should be present over most of the block although it may be locally eroded from the Hercynian highs as in Breagh and Crosgan. The Namurian consists of a fluvial deltaic stacked sand and shale sequence and is anticipated to be an effective reservoir with poroperm qualities generally as good, or better, than the Dinantian.

To the north of 42/14b, possible Namurian gas pay is present in well 41/10-2z but was not tested hence effectiveness is unproven. The net thickness in the Namurian is poorly constrained and porosities and permeabilities are likely to be fairly low although should be capably of potentially commercial gas rates especially if fractured. The Namurian is believed to be developed in more distal facies to the south of the block.

Play Reservoir Chance = 90% (Carboniferous)

Seal: the Permian Zechstein evaporates are the proven regional seals in the area. Top seal risk for Zechstein is low and hence any traps defined by the BPU will have a very high seal chance of success. The primary risk will be due to lateral seals associated with intra Carboniferous seals subcropping the BPU to form stratigraphic traps. Such seals have been proven in the area but are difficult to predict and identify on current seismic. Marine bands within the Namurian may be the best seals which should be possible to map with good seismic and be laterally persistent. Most of the traps on the block are also likely to be associated with faulting and may not seal especially if fault throw exceeds the shale seal thickness. The larger structures are often associated with large faults, and therefore have a greater seal risk.

Thief zones are also possible where the potential seals along the flanks of the trap are ineffective for gas. A thin Rotliegendes could act as a thief or waste zone in the south of the block. The risk of seal or trap integrity for this play takes account of the top and side seals.

Play Seal Chance = 60% (Carboniferous)

Charge: a regional source and effective charge is proven in the area but not on the licence. Most pre salt wells in the area indicate gas shows or some gas pay. Dry gas with low inerts are anticipated to be the hydrocarbon type in the Carboniferous. There is a risk associated with the effectiveness of migration routes, trap fill and gas saturations. Local charge is effective to the west (Breagh) and northeast of the licence area (Crosgan). Also to the east, a small gas discovery was made by well 42/15b-1 in the Triassic indicating effective migration pathways. The primary Westphalian source lies to the southeast with likely migration pathways updip into 42/14b. The primary focus for gas migration will be towards the Breagh and Crosgan structural highs so it is possible that by-pass areas exist on 42/14b. Deeper Namurian and Dinantian source rocks are also present and mature but have not yet been proved to be effective.

Play Charge Chance = 80% (Carboniferous),

Trap Potential: Axis has reviewed the old 3D seismic data purchased by CNR and there is clear evidence of subcropping Carboniferous events in the area which have the potential to form viable traps analogous to Crosgan and Pegasus (**Figures 3.5 and 3.6**). This play requires detailed mapping and rigorous depth conversion. Halokinensis due to Zechstein salt induces significant lateral velocity changes and hence depth conversion problems in the area. Detailed velocity modelling is required to effectively quantify trap size. As only the eastern edge of the block is covered by 3D seismic available to Cluff, high resolution seismic acquisition and reprocessing of current 3D seismic volumes is recommended.

Block 42/14b is transversed by a well-defined lineament, interpreted as a Mesozoic collapse zone, trending southwest-northeast. Seismic imaging of the objective Carboniferous is extremely poor in this area and structural mapping is further complicated by problematic depth conversion. Any existing depth maps in this area should be considered with caution and are unlikely to be valid given the quality of seismic imaging and velocity modelling. This area is unexplored on the block but there is no reason to suggest that viable traps do not exist within the Carboniferous if intra Carboniferous seals are effective. In addition, as the BPU regionally rises to the north west; any gas charge from the Westphalian source to the southeast may be trapped under or against the collapse zone. Prestack depth migration together with detailed velocity modelling will help to unlock the trap potential in this complex structural zone.

The overall play chance of success is circa 40-45% and considers the chance of the play to be effective on block 42/14b. It is the product of the reservoir, source and seal chance as summarised below:

Carboniferous Play Chance of Success			
Reservoir %	Charge %	Seal %	Overall %
90	80	60	43

Table 3-1: 42/14b Carboniferous Play Risk Assessment

3.3.1.2 Play Resource Assessment

Axis has assessed the play prospective resource size potential for the Carboniferous traps that are predicted to be present on block 42/14b.

An economic low case size field is anticipated to be in the range of 5 km^2 and a high case of 50 km^2. These areas define a log normal distribution with a best case of 16 km^2. The range of volumes also considers the fill factor which is linked to effective gas charge. The areas are consistent with drillable prospects in the area and the smaller gas discoveries such as Crosgan. The Breagh field is believed to have an area in excess of 80 km^2 based on published maps and this is equivalent to the (P_5) case area.

The reservoir parameters used for the volumetrics are based on the Breagh and Crosgan fields and the wells in the area. The range of net pay thicknesses considers gross, net to gross and the shape factor.

Reservoir quality is very variable ranging from good quality transgressive reworked sands to fine grained clay rich sandstones. In the Breagh field, the gross reservoir thickness is believed to be around 140 m and porosities in the range of 6-18%. In

Breagh well 42/13-2, the average porosity in the good 16 m sandstone is around 14% (**Figures 3.7 and 3.8**). Flow rates are encouraging; the Breagh appraisal well 42/13-3 was tested at circa 18 MMsf/d and the A08 platform well was on production at 42 MMscf/d after fraccing.

The Crosgan field is believed to have a gross hydrocarbon column in excess of 70 m. Gas is contained within the Lower Carboniferous Yordale, Whitby and Scremerston Formations. In the Crosgan well, 42/10-2z, the Whitby flowed at 8.6 MMscf/d. The best reservoir was in the Whitby Formation with a gross sandstone 30 m thick, 70% net to gross and porosities of 11-12%. This is consistent with the most likely case for the net pay. The Yordale and Scremerston Formations had lower porosities in the order of 5%.[15] The underlying Fell sandstone had no charge and very low porosity.

High flow rates (combined rate of 90 MMscf/d) were also achieved from the Pegasus West well 43/13b-7 believed to be from the Namurian sandstones. The Namurian, in well 41/10-2z, indicates stacked sandstones with a net to gross of over 30%. Well 41/10-1 encountered thick sandstones in the lower Carboniferous. The Yoredale sandstones are interpreted with over 60 m net sandstone in a number of sandstone intervals with porosities in the range of 6-13%.

The gas saturation is based on that found in Breagh and Crosgan and the gas expansion factor calculated from the ranges of temperature and burial depths. Traps directly underlying the BPU are likely to be at depths of 2,400 to 2,700 m. In Breagh well 42/13-2, the petrophysical analysis indicates gas saturations of 70% in the good sandstones (**Figure 3.7**). In Crosgan well 42/10-2z, saturations have been reported in the range of 50-70%, which is considered typical for the Carboniferous play.

The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS. The recovery at Breagh has been reported at approximately 60%.

The following table indicates a range of possible trap areas, reservoir and fluid parameters based on the regional geological and well information and considering the anticipated parameters at the objective depths on the block.

Carboniferous parameters			
	Low	**Best**	**High**
Area (km^2)	5	16	50
Net Pay Thickness (m)	10	22	50
Porosity (%)	5	10	14
Gas Saturation (%)	50	60	70
Formation Volume Factor (Gas)	220	230	240
Gas Recovery Factor (%)	40	60	80

Table 3-2: 42/14b Carboniferous Play Indicative Trap Size, Reservoir & Fluid Parameters

A Monte Carlo stochastic simulation was performed using the low and high parameters tabulated in **Table 3.2** and the hydrocarbon in place and potential resources estimates are given below:

	Low Estimate Bscf	Best Estimate Bscf	High Estimate Bscf
Gas in Place	32	146	620
Potential Gas Resources	17	85	369

Table 3-3: 42/14b Carboniferous Play, GIIP and Resource Estimates. for a Typical Carboniferous Trap. Based on the Parameters in Table 3-2.

The reservoir parameters and resource estimates for the Carboniferous play in block 42/14b have been benchmarked against similar Carboniferous fields in the basin. The Breagh field is believed to have a GIIP in the order of 1190 Bscf consistent with a P_5. Breagh ultimate reserves have been estimated at 700 Bscf. The Crosgan field GIIP is of the order of 155 Bscf (P_{50} contingent) and 69 Bscf (P_{50} prospective) consistent with the P_{50} or best case.[15] Pegasus North is assessed with gas (2C) resources in excess of 100 Bscf and Pegasus West with over 70 Bscf[16] consistent with the best case scenario.

It is anticipated, considering the structural style in the Carboniferous, that several small traps may exist on the block.

To assess the exploration resource potential in the block, Axis have estimated the possible average trap density for the Carboniferous plays.

We have assumed the density will be approximately 1-3 structures (based on an assumed most likely trap area of 16 km^2) for a typical North Sea block. The area of block 42/14b is 224 km^2. This density is consistent with the more mature areas within the Southern North Sea basin.

Based on the assumptions described above, a prospect portfolio would be expected to have an average resource size expectation equivalent to the best estimate or P_{50} value which is estimated to be 85 Bscf for the Carboniferous play. This value, together with the estimated number of prospects that would be expected in this type of structural setting and block size can be used to estimate an un-risked arithmetically summed prospective resource potential for a prospect portfolio as summarised in the **Table 3.4** below:

Carboniferous Play	Low (Bscf)	Best (Bscf)	High (Bscf)	Play Risk
Assumed Trap Number[15]	1	2	3	
Total Prospective Resource[16]	85	170	255	Medium

Table 3-4: 42/14b Carboniferous Play Prospective Resource Assessment

If the play is proven on block by an exploration well, the potential on block can be very significant. Assuming approximately two potential traps, and the best estimate resource value of 85 Bscf, the total unrisked prospective resources could be in the range of 170 Bscf.

This assessment is consistent with a CPR report on the Andromeda prospect in 43/13 mapped on 3D seismic data which has indicated best case prospective resources in the order of 80 Bscf on each of the Andromeda North and Andromeda South traps.[16]

The play chance of success does not take into account any prospect related risks. The prospect chance of success considers prospect specific risks for trap, seal, reservoir and charge. This play is considered to be medium risk; it is possible that given a well-defined structure based on good quality seismic, that the prospect chance of success may be in the range of 10-25% for the Carboniferous play.

[15] The estimated number of structural traps that are predicted to be identified in this structural setting from extensive good quality seismic data coverage, is assumed to be in the range of 1 to 3 for the Carboniferous.
[16] This is the product of the multiplication of the trap number by the P_{50} resource size. This is equivalent to arithmetically summing the best case values for individual opportunities. This estimate is unrisked.

3.4 Additional Potential

Although most traps are likely to be combined structural stratigraphic traps underlying the Base Permian Unconformity, there is also a high risk upside potential for larger resource volumes in deeper Carboniferous reservoirs assuming deeper Namurian and Dinantian source rocks and intra Carboniferous seals exist.

The Rotliegendes (Leman sandstone) is present to the south of the block based on regional maps. It may be present along the southern edge of the block which could also have the potential for stratigraphic traps.

The Zechstein potential has not been quantified. Several wells had gas shows in the area including 42/14-2. In the block to the east, well 42/15a-2 tested 7.6 MMscf/d gas, post acidization from the Hauptdolomite.[15]

Well 42/9-1, 10 km to the north, encountered circa 20 m of possible gas pay in the Hauptdolomite. The Zechstein carbonates are considered to be within a more distal facies than in the P2252 area.

The Bunter sandstone is well developed in the area and was the reservoir in the large (now depleted) Esmond, Forbes and Gordon gas fields. Well 42/14-1 was a Bunter test drilled along the southern edge of block to test a well along a northwest-southeastern structural trend. Legacy maps indicate that the well was drilled on structure, although approximately 200 m downdip from the crest. Legacy maps indicate that a similar structure may exist on block to the northwest. The risk is high especially due to migration risk from the Carboniferous source through the Permian salt into the overlying Triassic. Well 42/15b-1 in the adjacent block to the east was a small (believed to be approximately 20 Bscf) gas discovery; the gas is reported to have a high nitrogen content.[15]

4.0 LICENCE P2248

4.1 Geological Setting

Licence P2248 consists of block 43/11 which lies within the northwestern area of the UK Southern North Sea (SNS) basin (**Figures 1.1 and 4.1**). Several fields and discoveries occur in the area and many other wells have indications of gas pay or gas shows. The primary reservoirs are believed to be in Carboniferous (Namurian and Dinantian) sandstones. The Upper Permian (Zechstein) may also be prospective and several wells in the area have encountered gas shows although reservoir quality is usually poor and developed within a distal facies. The Lower Permian (Rotliegendes) sandstones are not expected but the pinch out is predicted close to the southern margin of 43/11 so local developed is possible in the south of the block. There is also a minor Triassic (Bunter sandstone) discovery in 42/15b-1. The single well 43/11-1, drilled in 1973, was an unsuccessful shallow Triassic test and hence the Palaeozoic reservoirs have not yet been drilled on the block.

The licence is surrounded by several producing fields and discoveries. The producing Breagh field (42/12 and 42/13) lies 40 km to the west with gas reserves believed to be in the order of 700 Bscf in lower Carboniferous (Dinantian) sandstones. The Crosgan discovery (42/10) lies 15 km to the northwest with gas resources circa 100 Bscf. Recent discoveries, 20 km to the east in 43/13, have been Pegasus and Pegasus West which have proved that the Namurian is an effective reservoir, capable of high flow rates and trapped by intra Carboniferous seals. The Namurian play has been underexplored in the area; the Kilmar field, 20 km to the southeast (**Figure 1.1**) is believed to be the only purely Namurian field currently on production in the basin. A number of large Westphalian Carboniferous gas fields lie further to the east in quadrants 43 and 44 (e.g. Murdoch, Caister, Boulton) and several small Carboniferous oil and gas fields lie onshore (e.g. Welton, Eakring, Beckingham, Gainsborough).

4.1.1 Reservoir

The primary objective is the middle Carboniferous Namurian deltaic sandstones at the top of the Carboniferous. Well logs from the middle Carboniferous in wells 43/13b-6z and 43/13b-4 are shown in **Figures 4.2 and 4.3** and indicate a stacked sand shale section with a high net to gross. Most of the upper Carboniferous Westphalian is believed to be eroded over much of the block below the BPU although there is evidence from seismic for outliers to exist on the block.

The deeper Dinantian reservoirs will also be present and have been confirmed to be effective in Breagh and Crosgan. However, on block 43/11 the reservoir is not anticipated to subcrop the BPU and is likely to be too deep to be prospective.

Most of the Westphalian has been eroded over the block but the older (Westphalian A) units may be present in the eastern part of the block and within outliers below the BPU (**Figure 3.3**). The younger Westphalian units (Westphalian B-D) are anticipated to occur to the east in blocks 43/12 and 44/13. A well log from the upper Carboniferous in well 43/12-1 is shown in **Figure 4.4**. The Westphalian A and Namurian reservoirs are productive in the Trent and Cavendish fields and Pegasus discovery (**Figure 4.1**).

The lower Permian (Rotliegendes) sandstones are considered to be generally absent in the area although isolated sandstones are possible especially in the south of the block. The lower Permian pinchout edge is poorly defined in the area. The wells to the west did not encounter Rotliegendes and the closest wells to the east (43/11-1 and 43/12-2) were Triassic tests. Well 43/12-1 encountered a lower Permian section but in the Silverpit shale facies.

The Zechstein is generally not well developed in the area and wells indicate thin carbonates and very low porosity.

The Triassic Bunter sandstones form thick effective reservoirs as in the depleted Esmond and Forbes fields. In the 42/15b-1 discovery, gas resources are estimated between 10-25 Bscf, with porosity 10-23% (most likely 16%) and a high net to gross of 90% (**Figure 3.4**).[15] However, the Bunter is not considered as a primary play due to migration risk and the lack of any significant undrilled structures on the block.

4.1.2 Charge

A regional source for gas and effective charge is proven in the area. The source for the gas is believed to be coal rich intervals in the Carboniferous from the coal measures of the Westphalian (upper Carboniferous); deeper coals in the middle and lower Carboniferous may also have generated gas. Secondary sources may include the Zechstein marine shales and marine bands in the Namurian. The upper Westphalian is present to the east and the lower Westphalian A is present over much of 43/11 (**Figure 3.3**). There is currently no evidence of gas accumulations deeper within the Carboniferous or deeper effective intra Carboniferous seals. However, there has been a limited number of well penetrations into or through the Carboniferous section, partly due to the poor seismic imaging. The gas is methane rich and some oil and condensate have also been encountered in the basin.

Regional burial plots indicate that uplift occurred in the Permian, Jurassic and Tertiary although not so pronounced as in the licences to the north and west. The deepest burial will have occurred in the mid Tertiary so subsequent uplift may have arrested gas generation. Generation will still be occurring to the southeast towards the basin depocentre where the Westphalian is present and is the dominant source rock.

4.1.3 Traps

Block 43/11 lies to the west of the Cavendish (43/19)-Pegasus (43/13) high trend. The trend extends into 43/12 where a potential large intra Carboniferous trap (Andromeda prospect) has been mapped and this high trend may extend further west into 43/11 (**Figure 4.5**).

The Breagh field and Crosgan discovery to the west are well defined faulted dip structures at the level of the Base Permian Unconformity. The legacy structure maps, available on 43/11, do not show that any significant closures exist on the block at the BPU level (**Figure 4.5**). However, as the Carboniferous subcrops the BPU, there is excellent potential for traps requiring a combination of Base Permian and intra Carboniferous seals (**Figure 4.6**). Such traps have not been historically explored for in the 43/11 area but have recently proved to be viable for example in the nearby Pegasus and Pegasus West (43/13b) discoveries. Intra Westphalian seals are also effective to the west in many fields onshore the U.K. including the Saltfleetby field, onshore Lincolnshire which has a reported gas column of 91 m.

The Namurian shales are likely to be effective seals. The marine bands are potential regional seals and indicate flooding surfaces as in wells 43/20b-2 and 44/16-1z.[10] The ultimate seals are the Zechstein evaporites. The lower Permian Silverpit shales may also be present in the south eastern part of the block.

A well-defined dip closure at the Triassic (Bunter) level exists on the block and was drilled by the unsuccessful 43/11-1 well although it was not a crestal test on the 3D seismic (**Figure 4.7**). The seismic, studied by Axis, indicates significant crestal faulting and hence a substantial seal risk even if migration had been effective through the Zechstein salt. A small secondary closure exists to the north but it is unlikely that any significant Bunter potential remains on block.

4.2 Previous Drilling

Centrica was the previous operator in licence P1334 consisting of blocks 43/11 and 43/12. The area was initially a promote licence to WHAM Energy and was then awarded in the 23rd round, 100% to Centrica.

Well 43/11-1 was drilled in 1973 by Zapata. The well was a Triassic test and drilled into Zechstein salt with minor shows in the Bunter sandstones. The structure is a well defined dip closure and 43/11-1 was drilled within closure but possibly some 50 m from the crest hence minor gas potential could exist updip. The crest of the structure is significantly faulted so it is possible that any accumulation would be breached. Charge is also a significant risk as there are no clear migration pathways into the structure.

Well 43/12-1 was drilled by LASMO in 1984. The well was a Bunter test (with amplitude support) but found to be water bearing. The trap appears to be a valid four-way dip closure from the seismic and the well was drilled near to the crest. The well was deepened to the Carboniferous and a 150 m section was drilled of Westphalian sandstones and shales but with no shows. It is believed that no structure exists at the Base Permian Unconformity level.

43/12-2 was a Bunter test drilled by LASMO in 1988. The Bunter was dry although apparently was drilled on structure and close to the crest. Again migration through the salt, would have been the principal risk.

43/13b-4 was drilled by LASMO in 1991. The Westphalian target was absent but the well found a Namurian sand and shale section. Gas shows were encountered and the well was tested but with no flow due to apparent low permeability. There were also thin tight Rotliegendes sandstones close to the base of the Silverpit Shale section but less than 2 m thick.

Well 43/13b-6z was drilled by Centrica in 2010. Gas pay was encountered in good Namurian sandstones but the well was not tested due to mechanical problems. Seismic indicates no trap at the BPU, but closure within the Carboniferous indicating a stratigraphic trap subcropping the unconformity.[17]

The best rates were from the Pegasus West well (43/13b-7), drilled in 2014, which tested at a combined rate of 91 MMcf/d from three Carboniferous intervals.

4.3 Prospective Resources

The Carboniferous play is currently unproven within block 43/11, although it is proven in the area for example in the Pegasus discoveries and the Crosgan field. The evaluation of the block by CNR is at an initial stage and no prospects and leads have currently been identified that may be evaluated for prospective resources at the prospect or lead level. However, the Carboniferous play is considered very prospective on the block and Axis have therefore assessed the potential at the play level as defined by PRMS guidelines (**Figure APP1-2, Appendix 2.2**). Potential also exists in the Permian (Zechstein and Rotliegendes) and Triassic but these are considered less prospective, high risk and have not been considered further for prospective resources.

The assigned risks are attributable at the play level and indicate the chance that the Carboniferous play is viable on block. The play chance of success considers reservoir, seal effectiveness and gas charge.

Further seismic acquisition and reprocessing by CNR will likely result in potential traps being identified and some may be matured to drillable prospects. Detailed seismic interpretation and depth conversion is required to identify traps accurately, constrain volumetrics and to reduce risk.

Drilling by other operators in neighbouring areas is likely, leading to further risk reduction if these drilling programmes are successful.

4.3.1 Carboniferous Play

4.3.1.1 Chance of Success

Reservoir:

In 43/11, the Namurian is predicted to be subcropping the Base Permian Unconformity over the block where the lower Westphalian A is absent. The presence of effective Carboniferous Namurian reservoir in the area is confirmed by the Pegasus and Pegasus West discoveries in 43/13b. In these fields, the Westphalian Carboniferous is absent or very thin so the gas pay is mainly in the underlying Namurian, middle Carboniferous sequence. The Namurian was tested by the recent Pegasus (43/13b-6z) and Pegasus West wells (43/13b-7). The best rates were from Pegasus West which tested at a combined rate of 91 MMcf/d from three Carboniferous intervals. The high commercial rates are believed due to the leading edge drilling and testing practices in a reservoir that historically has had low productivity. Namurian sandstones also provide most of the production in the Trent and Kilmar fields and secondary reserves in the Cavendish field (**Figure 4.1**).

The Namurian sandstone source is from current area of the Mid North Sea High to the north. The Namurian consists of a fluvial deltaic stacked sand and shale sequence and is anticipated to be an effective reservoir with poroperm qualities generally as good, or better, than the Dinantian. The net to gross is high (**Figures 4.2 and 4.3**) although a more distal facies is developed to the south. There is a general coarsening up in the section with basin infilling of widespread delta front sediments and finally to the fluvial deltaics of the Millstone Grit.

The pattern was of stacked progradational fluvio-deltaic sequences with intercalated marine bands with the upper section being more sandstone rich. Reservoir quality is likely to be very variable; the transgressive reworked sandstones are cleaner, coarser and will have the best reservoir characteristics. The poorer reservoirs are more clay rich with low permeabilities.

Many of the sandstones are immature and arkosic rich that have tended to reduce effective permeabilities. Modern optimization techniques are leading to economic flow rates from these traditionally tight reservoirs. Burial depth also severely effects reservoir quality; typically Namurian depths are of the order of 3000-3500 m on block although it is estimated that regional uplift may be up to 1000 m.

The Westphalian is a proven prolific gas reservoir to the east of the block in the eastern part of quadrant 43 and 44 where there are many fields (Ketch, Boulton, Murdoch). On much of block 43/11, the basal Westphalian A will be present. The Westphalian A sub fairway incorporates the uppermost beds of the Millstone Grit Formation and the Caister Coal.[10]

The Cavendish and Trent are fields with Westphalian gas resources (**Figure 4.1**). The Westphalian A, typically 400-550 m thick, is composed of fluvial distributary channel facies, lake and swamp mudstones and coals. Distributary channel porosity and permeability in the Trent field are in the range of 5-13 % and 50-60 mD; net to gross is typically 20-40%.[10]

It is highly likely that sandstones will be encountered within any trap. However the facies and quality is difficult to predict. The Namurian and lower Westphalian sandstone intervals are very variable and laterally discontinuous. They are generally thin (10-20 m thick) and interbedded with shale units of generally similar frequency and thickness. The lower Namurian appears to have a higher shale content as in Pegasus well 43/13b-6z. The main risk for achieving economic flow rates will be due to reservoir permeability and connectivity.

Play Reservoir Chance = 90% (Carboniferous)

Seal: the Permian Zechstein evaporates, and locally also the Silverpit Shales, are the proven regional seals in the area. Top seal risk is low and hence any traps, defined by the BPU, will have a very high seal chance of success. The primary risk will be due to lateral seals associated with intra Carboniferous seals and faults subcropping the BPU to form combination traps. Such seals have been proven in the area but are difficult to predict and identify on current seismic. Marine bands within the Namurian may be the best seals which should be possible to map with good seismic and be laterally persistent. Most of the traps on the block are likely to be fault dependant traps and may not seal especially if fault throw exceeds the shale seal thickness. The larger structures are often associated with large faults, and therefore have a greater seal risk.

The play has not been tested on block and is underexplored in the area. Historically, the intra Carboniferous has not been mapped in detail, partly due to the poor quality of legacy seismic within the Carboniferous and, because of the perceived risks associated with Carboniferous seals.

Thief zones are also possible where the potential seals along the flanks of the trap are ineffective for gas. A thin Rotliegendes sandstone could act as a thief or waste zone. The risk of seal or trap integrity for this play takes account of the top and side seals.

Play Seal Chance = 60% (Carboniferous)

Charge: a regional source and effective charge is proven in the area but not on the licence. Dry gas with low inerts are anticipated to be the hydrocarbon type in the Carboniferous. Most pre salt wells in the area indicate gas shows or some gas pay. The primary Westphalian source lies on block or directly to the southeast with likely migration pathways updip into 43/11. Local charge is effective to the west (Breagh), northeast (Crosgan) and east (Pegasus). Deeper Namurian and Dinantian source rocks are also present but have not yet been proved to be effective. Block 43/11 lies updip from the Pegasus area in 43/13 and along a possible migration pathway to the Crosgan / Breagh area. Also to the west, a small gas discovery was made by well 42/15b-1 in the Triassic indicating local migration pathways through the Zechstein.

There is a risk associated with the effectiveness of migration routes, trap fill and gas saturations. There is little evidence to prove or disprove if traps are fill to spill point although the significant gas accumulations at Breagh, Pegasus and Crosgan indicate effective charge. All these fields lie along or close to structural highs that would be a focus for regional migration.

Play Charge Chance = 80% (Carboniferous),

Trap Potential: Block 43/11 lies to the west of the Cavendish (43/19)-Pegasus (43/13) High trend. The area is covered by a 3D seismic survey and Axis has reviewed the seismic and legacy structure maps in the area in the CNR data base.

No significant traps are indicated on the legacy maps at the BPU level over the block. However, there is clear evidence of subcropping Carboniferous events in the area which have the potential to form viable traps analogous to Crosgan and Pegasus (**Figure 4.6**). The Carboniferous high trend extends into 43/12 where a potential large intra Carboniferous trap (Andromeda prospect) has been mapped (**Figures 4.5 and 4.7**). This trend continues into 43/11 and traps may exist by subcropping sealing units to effect closure updip to the west (**Figure 4.5**). This play requires detailed mapping and rigorous depth conversion. Halokinensis due to Zechstein salt induces significant lateral velocity changes and hence depth conversion problems in the area (**Figure 4.7**). Detailed velocity modelling is required to effectively quantify trap size. The block is covered by legacy 3D seismic but the seismic is generally poor at the Carboniferous level with an acquisition footprint and could benefit from reprocessing and eventually new broadband acquisition.

The Mesozoic collapse zone identified in 42/14 trends SW-NE and transverses the north-western edge of block 43/11. Any existing depth maps in this area should be considered with caution and are unlikely to be valid given the quality of seismic imaging and velocity modelling.

The pre salt is undrilled on the block and there is no reason to suggest that viable traps do not exist within the Carboniferous if intra Carboniferous are effective.

Faults, commonly trending north-west, may also develop traps (**Figure 4.5-4.7**). The regional dip and migration pathways are up to the north west at the level of the BPU, so potential trapping geometries will require intra Carboniferous and / or cross faults to effect closures along the western margins. A structural nose has been mapped in the south western part of the block as seen on the BPU map (**Figure 4.5**).

The overall play chance of success is 40-45% and considers the chance of the play to be effective on block 43/11. It is the product of the reservoir, source and seal chance as summarised below:

Carboniferous Play Chance of Success			
Reservoir %	Charge %	Seal %	Overall %
90	80	60	43

Table 4-1: 43/11 Carboniferous Play Risk Assessment

4.3.1.2 Play Resource Assessment

Axis has assessed the play prospective resource size potential for the Carboniferous traps that are predicted to be present in the block 43/11.

An economic low case size field is anticipated to be in the range of 5 km^2 and a high case of 50 km^2. These areas define a log normal distribution with a best case of 16 km^2. The range of volumes also considers the fill factor which is linked to effective gas charge. The range of areas are consistent with drillable prospects in the area and the gas discoveries such as Crosgan and Pegasus. The Breagh field is believed to have an area in excess of 80 km^2 based on published maps and this is equivalent to the (P_5) case area. The regional maps indicate that the Pegasus North and Pegasus South traps have a maximum area in the order of 50 km^2 and the areas of the Andromeda North and South prospects are consistent with the best case area.

The reservoir parameters used for the volumetrics are based on the Pegasus discovery and the wells in the area. Reservoir quality is very variable ranging from good quality transgressive reworked sands to fine grained clay rich sandstones. The range of net pay thicknesses considers gross, net to gross and the shape factor.

The Pegasus well 43/13b-6z encountered three sandstone gas pay units within the Namurian. Net pay thickness is nearly 50 m over a 70 m gross column in the pay zone (Figure 4.2). However, for the gross 500 m section the net to gross was significantly less at approximately 17%, although over 40% in the upper interval.

The thickness of gas pay reservoir will be therefore highly dependent on the sandstone thicknesses close to the top Carboniferous below the BPU. The average porosity in the pay zone is around 5-14% with an average of 11%. Core data is shown in **Figure 4.8**. Gas saturation varies between about 75% in the top sandstone, to 60% close to the free water level at 3,513 m TVDss. The well was abandoned without testing due to mechanical problems. However, the Pegasus West well (43/13b-7) was successfully tested and flowed at a combined rate of circa 91 MMscf/d from three Carboniferous intervals.

The Crosgan field is believed to have a gross hydrocarbon column in excess of 70 m within the Dinantian.[15] In the Crosgan well, 42/10-2z, the Whitby flowed at 8.6 MMscf/d. The gross sandstone was 30 m thick with 70% net to gross and porosities in the range of 10-12%. This is consistent with the most likely case for the net pay. The Yordale and Scremerston Formations had lower porosities in the order of 5%.[15] The underlying Fell sandstone had no charge and very low porosity.

The gas saturation is based on that found in Pegasus, Breagh and Crosgan. In Pegasus, the petrophysical analysis indicate gas saturations of 40-75%. In the Breagh well 42/13-2, the petrophysical analysis indicates gas saturations up to 70% in the good sandstones. In the Crosgan well 42/10-2z, saturations have been reported in the range of 50-70% which is considered typical for the Carboniferous play.[15] The gas expansion factor was calculated from the ranges of temperature and burial depths. Traps directly underlying the BPU are likely to be at depths of 3,000 m. Compared to block 42/14b, the primary objectives below the BPU are likely to be 200-500 m deeper but palaeodepths are likely to be similar as inversion was more significant to the west.

The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS. The recovery at Breagh has been reported at approximately 60%.

The following table indicates a range of possible trap areas, reservoir and fluid parameters based on the regional geological and well information and considering the anticipated parameters at the objective depths on the block.

Carboniferous parameters			
	Low	**Best**	**High**
Area (km^2)	5	16	50
Net Pay Thickness (m)	10	22	50
Porosity (%)	5	10	14
Gas Saturation (%)	50	60	70
Formation Volume Factor (Gas)	240	250	260
Gas Recovery Factor (%)	40	60	80

Table 4-2: 43/11 Carboniferous Play Indicative Trap Size, Reservoir & Fluid Parameters

A Monte Carlo stochastic simulation was made using the low and high parameters tabulated in **Table 4.2** and the hydrocarbon in place and potential resources estimates are given below:

	Low Estimate Bscf	**Best Estimate Bscf**	**High Estimate Bscf**
Gas in Place	34	158	657
Potential Gas Resources	19	91	393

Table 4-3: 43/11 Carboniferous Play, GIIP and Resource Estimates for a Typical Carboniferous Trap. Based on the Parameters in Table 3.2.

The reservoir parameters and resource estimates for the Carboniferous play in block 43/11 have been benchmarked against similar Carboniferous fields in the basin. The Breagh field is believed to have a GIIP in the order of 1190 Bscf consistent with a P_5. Breagh ultimate reserves have been estimated at 700 Bscf. The Crosgan field GIIP is of the order of 155 Bscf (P_{50} contingent) and 69 Bscf (P_{50} prospective) consistent with the P_{50} or best case. Pegasus North is assessed with gas (2C) resources of over 100 Bscf and Pegasus West with over 70 Bscf[16]consistent with the best case scenario. This assessment is also consistent with the prospective resources in the Andromeda prospect in 43/13 which is mapped on 3D seismic data and is analogous to Pegasus. Best case prospective resources have been estimated as circa 80 Bscf on each of the Andromeda North and Andromeda South traps.[16]

It is anticipated, considering the structural style in the Carboniferous, that several small traps may exist on the block. To assess the exploration resource potential in the block, Axis have estimated the possible average trap density for the Carboniferous plays.

We have assumed the density will be approximately 1-3 structures (based on an assumed most likely trap area of 16 km^2) for a typical North Sea block and the area of block 43/11 is 240 km^2. This density is consistent with the more mature areas within the Southern North Sea basin.

Based on the assumptions described above, a prospect portfolio would be expected to have an average resource size expectation equivalent to the best estimate or P_{50} value which is estimated to be 90 Bscf for the Carboniferous play.

This value, together with the estimated number of prospects that would be expected in this type of structural setting and block size can be used to estimate an un-risked arithmetically summed prospective resource potential for a prospect portfolio as summarised in the **Table 4.4** below:

Carboniferous Play	Low (Bscf)	Best (Bscf)	High (Bscf)	Play Risk
Assumed Trap Number[17]	1	2	3	
Total Prospective Resource[18]	90	180	270	Medium

Table 4-4: 43/11 Carboniferous Play Prospective Resource Assessment

If the play is proven on block by an exploration well, the potential on block can be very significant. Assuming approximately 2 potential traps, and the best estimate resource value, the total unrisked prospective resources could be in the range of 180 Bscf.

The play chance of success does not take into account any prospect related risks. The prospect chance of success considers prospect specific risks for trap, seal, reservoir and charge. This play is considered to be medium risk; it is possible that given a well-defined structure based on good quality seismic, that the prospect chance of success may be in the range of 10-25% for the Carboniferous play.

4.4 Additional Potential

Although most traps are likely to be combined structural stratigraphic traps underlying the base Permian Unconformity, there is also a high risk upside potential for larger resource volumes in deeper Carboniferous reservoirs assuming deeper source rocks and intra Carboniferous seals exist.

The Rotliegendes (Leman sandstone) is present to the south of the block based on regional maps. It may be present along the southern edge of the block which could also have the potential for stratigraphic traps.

[17] The estimated number of structural traps that are predicted to be identified in this structural setting from extensive good quality seismic data coverage, is assumed to be in the range of 1 to 3 for the Carboniferous.

[18] This is the product of the multiplication of the trap number by the P_{50} resource size. This is equivalent to arithmetically summing the best case values for individual opportunities. This estimate is unrisked.

The Zechstein potential has not yet been quantified but analogous plays exist within the Southern North Sea and the onshore Netherlands. Several wells had gas shows in the area including 42/14-2. In the block to the west, well 42/15a-2 tested 7.6 MMscf/d gas post acidization from the Hauptdolomite. The Zechstein carbonate in 43/11 are considered to be within a more distal facies than in the P2252 area.

The Bunter sandstone is well developed in the area and was the reservoir in the large (now depleted) Esmond, Forbes and Gordon gas fields. Well 43/11-1 was a Bunter test drilled in the western part of the block to test a well-defined dip closure (**Figure 4.7**). The well is recorded as a dry hole with minor, insignificant gas shows. Legacy maps indicate that the well was drilled on structure, although approximately 200 m downdip from the crest and the seismic indicates significant crestal faulting hence seal risk. A small undrilled structure exists on block to the north. The risk is high especially due to migration risk from the Carboniferous source through the Permian salt into the overlying Triassic. Well 42/15b-1 in the adjacent block to the west was a small (believed to be approximately 20 Bscf) gas discovery; the gas is reported to have a 20% nitrogen content.[15]

5.0 LICENCE P2261

5.1 Geological Setting

Licence P2261 consists of blocks 43/7, 43/8 and 43/9 which lies within the northern area of the UK Southern North Sea (SNS) basin. The eastern part of the licence, covering most of block 43/9, is considered off limits for hydrocarbon exploration as it is the planned site of an offshore windfarm (**Figure 1.1**).

The primary reservoirs are believed to be in the Permian Rotliegendes sandstones, Carboniferous (Namurian and Dinantian) and the Triassic. The Zechstein is historically not considered a play in the area but is underexplored so represents a high risk secondary target.

The closest fields are the abandoned Triassic gas fields of Forbes (43/8), Esmond (43/13) and Gordon (43/19). Forbes lies within licence P2261 in the southern part of 43/8. The field is worked out and no remaining resources have been assumed. The nearest Carboniferous fields are Crosgan (42/9) in the Dinantian, 30 km to the southwest, and Pegasus (43/13), 20 km to the south in the Namurian (**Figure 5.1**).

The area lies to the north of the prolific Carboniferous fairway in the southern part of quadrants 43 and 44 (Pegasus, Cavendish, Trent, Tyne). It also lies 40 km to the north west of the Cygnus field which has reserves primarily in the Lower Permian Rotleigendes sandstones and also in the Carboniferous (**Figure 1.1**). The discovery of the Cygnus field has significantly upgraded the area to the northwest, towards licence P2261 and along the southern margins of the Mid North Sea High. This area is underexplored and it was previously assumed that any Rotliegendes development would be very thin in this area to the north of the shale facies of the Silverpit Formation.

The Cygnus filed is currently under development. It was discovered in 1998; the project was sanctioned in 2012 and first gas is scheduled in 2016. The operator GDF, has quoted 2P gas reserves of 110 MMboe (over 600 Bscf). The field is the sixth largest field in the UK SNS and the largest gas field for 25 years. The reservoir is of good quality and high flow rates, circa 30 MMscfd, were achieved from tests in wells 44/12a-3 and 44/12a-4.

The licence is significantly underexplored. Apart from the Forbes field, there are only two wells on the licence (43/7-1 and 43/8-2) which were both old shallow Triassic tests. To the west, 43/6-1 encountered Zechstein on Carboniferous and the Rotliegendes facies was absent.

5.1.1 Reservoir

The primary objectives are the Permian and Carboniferous sandstones overlying and subcropping the BPU.

The licence lies towards the northern edge of the basin and the age of the subcropping Carboniferous generally is older to the north and west across the licence. However, there are no Carboniferous wells on the licence so the precise ages of the subcropping Carboniferous is speculative. The Westphalian (mainly Westphalian A) deltaic sandstones are likely to be present in the south and eastern areas of the licence (**Figure 5.2**). To the north and west, the upper Carboniferous Westphalian is believed to be eroded with the Namurian subcropping the BPU as indicated in well 43/6-1. The Dinantian may subcrop in the north west (**Figure 5.2**). All the Carboniferous intervals are likely to have reservoir sandstones capable of economic flow rates. The nearest analogy for the Westphalian reservoirs is the Cavendish field (43/24); for the Namurian, the Pegasus discovery (43/13) and for the Dinantian, the Crosgan (42/10) and Breagh fields (42/13). The lower Dinantian, the Fell sandstone, is generally too deeply buried in the area but may be prospective in the north west of the licence where it may be shallower and close to the BPU.

The main risks in the area have historically been well deliverability from relatively tight Carboniferous reservoirs and the absence of a Rotliegendes sandstone fairway. These risks have been reduced by the Pegasus North and West discoveries and the success of the Rotliegendes Cygnus field in 44/11 and 44/12. Many of the sandstones are immature and arkosic especially in the more proximal facies towards the Mid North Sea High. Enhanced production techniques, result in the Carboniferous being capable of economic rates especially where fractured. The Carboniferous reservoirs are generally sourced from the Mid North Sea High to the north so are likely to be more proximal and potentially in better facies than in the producing fields to the south. Porosity and permeability characteristics may be substantially improved due to early dissolved pore space feldspar by early migrant fluids.

The lower Permian (Rotliegendes) sandstones are likely to be developed, at least over parts of the licence area, although there is very limited well control. All the wells within the licence area were shallow Triassic tests so the development of any Permian sandstone has not been explored in the area. The Cygnus field (44/11 and 44/12) lies 40 km to the southeast and has thick and good quality sandstones developed along the northern area of the Silverpit Shale lacustrine facies. The Cygnus wells encountered pay in Rotliegendes sandstones in the order of 30 to 40 m thick with high net to gross and test rates circa 30 MMscf/d. The lower Permian pinchout edge is poorly defined in the area. The 43/6-1 well, to the west of the licence, encountered no lower Permian facies and the Zechstein overlies the Carboniferous Namurian at the BPU.

The region may have been an elevated area at BPU times with the potential of sandstones onlapping onto the high. To the east of the licence area, a thin Rotliegendes sandstone was encountered in 44/6-1.

To the south in 43/13-4, there is circa 5 m of sandstone in two thin units with good gas shows. There is reasonable expectation for Rotliegendes sandstones to be developed in the licence area especially in the south east of the licence towards Cygnus although thickness will be difficult to predict with the current well and seismic database.

The reservoirs in the upper Permian Zechstein reservoirs consist of the Plattendolomite and the underlying Hauptdolomite. The Zechstein is generally not well developed in the area and wells indicate thin carbonates and very low porosity. Wells in the area (43/6-1, 43/2-1, 43/3-1, 43/5-1) have not encountered significant shows.

The Triassic Bunter sandstones form regional thick effective reservoirs, as encountered in the depleted Esmond, Forbes and Gordon fields. Reserves for the combined fields have been quoted at over 500 Bscf. The sandstone is typically of the order of 100 m thick with a high net to gross.

5.1.2 Charge

A regional source for gas and effective charge is proven in the area. The source for the gas is believed to be coal rich intervals in the Carboniferous either from the coal measures of the Westphalian (upper Carboniferous) or the deeper coals in the middle and lower Carboniferous. Secondary sources may include the Zechstein marine shales and organic rich marine bands in the Namurian. The Westphalian A is present over much of the licence and the overlying Westphalian B may be present in the south of the licence. The gas is anticipated to be methane rich in the Carboniferous, the Triassic may have some nitrogen (typically 10-20%). The Carboniferous facies is developed in a more proximal facies to the north of the main producing gas kitchen. However, the gas fields such as in Gordon, Esmond, Crosgan and Cygnus indicate significant generation to the south and west; the Forbes field on block 43/8 indicate effective charge and migration at least in the southern part of the licence. The Bunter structures tend to be only partially filled probably due to the tortuous migration pathways along faults through the Zechstein.

There is currently no evidence in the area of gas accumulations deeper within the Carboniferous although. secondary source rocks may exist in the Namurian and Dinantian. The Dinanatian is believed to be relatively lean in the area but there are some high TOC values in the Namurian in the northern parts of quadrants 43 and 44 especially towards the Cygnus field. However, source rock maturity decreases significantly to the north east of the P2261 licence area.

Regional burial plots indicate that significant uplift occurred in the Permian, Jurassic and Tertiary. The deepest burial will have occurred in the mid Tertiary so subsequent uplift may have arrested gas generation. Hydrocarbon generation will still be occurring to the southeast of the licence towards the basin depocentre where the Westphalian is present and the dominant source rock.

Charge will be a higher risk in the north of the licence area at a greater distance from the discovered gas fields and the mature source kitchens.

5.1.3 Traps

Axis has reviewed the seismic and legacy structure maps in the area in the CNR data base. 3D seismic is only available on part of 43/7 and a loose 2D grid is available on the rest of the area.

The Bunter structures are well defined over the licence area. Dip and fault dependant closures have been drilled by the three exploration wells on the licence 43/7-1, 43/8-1 and 43/8-2. Well 43/8-1 was the Forbes field discovery well. Good reservoir and seals exist so it is believed all wells are dry due to lack of effective migration paths, fault seal or insufficient fill if the wells were drilled downdip. There may be some potential in smaller structures or updip of these wells.

Block 43/7 is transversed by a well-defined lineament, interpreted as a Mesozoic collapse zone, trending southwest-northeast across the block (**Figure 5.3**). This is the same lineament that was identified in block 42/14 which passes across the northern edge of 43/11 and through 43/6. Seismic imaging of the objective Carboniferous is extremely poor in this area and structural mapping is further complicated by problematic depth conversion. Any existing depth maps in this area should be considered with caution and are unlikely to be valid given the quality of seismic imaging and velocity modelling. The block is undrilled at the level of the Palaeozoic objectives. However, there is no reason to suggest that viable traps do not exist especially if intra Carboniferous seals are effective. In addition, as the BPU regionally rises to the northwest; any gas charge from the Westphalian source to the southeast may be trapped under or against the collapse zone. Prestack depth migration together with detailed velocity modelling will help to unlock the trap potential in this complex structural zone.

The Breagh field and Crosgan discovery to the west are well defined faulted dip structure at the level of the Base Permian Unconformity. The legacy structure maps available on 43/7 do not show any significant closures exist on the block at the BPU level. However, as the Carboniferous subcrops the BPU, there is excellent potential for traps requiring a combination of Base Permian and intra Carboniferous seals (**Figure 5.4**). Such traps have not been historically explored in the area but have recently proved to be viable for example in the nearby Pegasus and Pegasus West (43/13b) discoveries to the south.

Intra Westphalian seals are also effective to the west in many fields onshore the U.K. including the Saltfleetby field, onshore Lincolnshire which has a reported gas column of 91 m.

The Namurian shales are also likely to be effective seals. The marine bands are potential regional seals and indicate flooding surfaces as in wells 43/20b-2 and 44/16-1z.[10] The ultimate seals are the Zechstein evaporites. The lower Permian Silverpit shales may also be present in the south eastern part of the licence.

5.2 Previous Drilling

43/6-1 lies approximately 2 km west of block 43/7. It is believed to have encountered a 100 m lower Namurian section and 300 m of lower Carboniferous and the Rotliegendes was absent. Possible gas occurred in the Scremerston but there were no tests. Seismic indicates the well was drilled in a complex area associated with the Mesozoic collapse zone. The present seismic data has very poor imaging and it is unlikely that the well was drilled on structure. The seismic lines do show a clear subcrop of Carboniferous below the Zechstein (**Figure 5.7**). There is also seismic evidence of a lower Permian section developed away from the well especially to the east into block 43/7.

43/7-1 was a Bunter test and was drilled on the flanks of the Mesozoic collapse zone. Seismic is very difficult to interpret; the well was drilled some distance from the crest and unlikely to be within closure.

Well 43/8-1 was the Forbes field discovery. The well was drilled on a well-defined four way dip closure overlying a Zechstein salt pillow.

43/8-2 was an unsuccessful Triassic Bunter test. Legacy 2D seismic indicates a possible fault dependant trap that relies on a southerly bounding fault. The fault continues up into the Cretaceous so there is risk of seal breach even if gas could have migrated through the Zechstein. There is no evidence of salt withdrawal as a viable migration route for gas to migrate into the structure.

The wells in 43/13a are shallow Bunter tests in the Esmond field. The Pegasus discoveries lie 10 km south of licence P2261 in 43/13b. The Pegasus discovery well, 43/13b-6z, was drilled by Centrica in 2010 and the Pegasus West discovery in 2014. Gas pay was encountered in good Namurian sandstones but the well was not tested due to mechanical problems. Seismic indicates no well at the BPU but closure within the Carboniferous indicating a stratigraphic trap subcropping the unconformity. The best rates were from the Pegasus West well (43/13b-7), which tested at a combined rate of 91 MMcf/d from three Carboniferous intervals.

5.3 Prospective Resources

The resource volumes for the leads on P2261 are reported in **Table 5.1** are gross on licence. CNR currently have a 100% working interest in the licence so the gross and net volumes are identical.

Prospective Resources for the Leads in Licence P2261 (Bscf)								
Lead	**Gross on Licence**			**Net Attributable**			**Risk Factor %**	**Operator**
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Clachnaharry	9	43	207	9	43	207	12	CNR
Williamson	10	20	40	10	20	40	27	CNR
Total Gas	19	63	247	19	63	247		

Table 5-1: Prospective Resources in the Leads in Licence P2261 Gross and Net[19]

The location of the two leads are shown in **Figure 5.5**. A more detailed description of the individual lead resource and risk assessment is included in the asset description sections of this report (**Sections 5.3.1 to 5.3.2**).

The Bunter play is proven by the Forbes field on the licence in 43/8. The Permian Rotliegendes play has not been proven on block but is the primary reservoir in the Cygnus field directly to the south east.

[19] **Net Attributable** is net working interest to CNR and is not necessarily the same as net entitlement. Net working interest is that portion of the gross resources attributable to the equity interest owned by CNR. Net entitlement will depend on the contractual terms of the licence at the time of any eventual hydrocarbon production.
Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Prospective resources are the volumes expected to be recovered from UPIIP (undiscovered petroleum initially in place) under conceptual projects, conditional on discovery and development.
Low, Best and High Estimate: in a probabilistic resource size distribution these are the P_{90} (90% probability), P_{50}, and P_{10}, respectively, for individual opportunities.
Risk Factor for prospective resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the prospective resource maturing into a contingent resource. Prospective resources have both an associated chance of discovery (geological chance of success) and a chance of development (economic, regulatory, market and facility, corporate commitment and political risks). The chance of commerciality is the product of these two risk components. These estimates have been risked for chance of discovery but not for chance of development.
Totals do not take account of prospect dependencies and have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.

The Carboniferous has not been proved on the block but is the reservoir in the Pegasus field directly south in 43/13b. The assigned risks are attributable to the specific leads primarily due to trap, reservoir and seal effectiveness. Further detailed seismic interpretation and depth conversion is required to map the leads accurately, to reduce risk and to upgrade any lead into drillable prospects. It is likely that the resource ranges will be substantially narrowed if rigorous mapping and depth conversion confirms the trapping integrity and areal extent of these leads. Drilling by other operators in neighbouring areas is likely and further risk reduction will occur if these drilling programmes are successful. Further studies and seismic acquisition, outside the current 3D area in 43/7, by CNR are likely to result in new potential traps being identified and some may be matured to drillable prospects.

The Carboniferous play is currently unproven within the licence although it is proven in the Pegasus discoveries to the south. The evaluation of the block by CNR is at an initial stage and no Carboniferous prospects and leads have currently been identified that may be evaluated for prospective resources at the prospect or lead level. However, the Carboniferous play is considered very prospective on the block and Axis have therefore assessed the potential at the play level as defined by PRMS guidelines (**Figure APP1-2, Appendix 2.2**). The resource volumes for the Carboniferous play are tabulated below:

Carboniferous Play	Low (Bscf)	Best (Bscf)	High (Bscf)	Play Risk
Assumed Trap Number[20]	1	3	5	
Total Prospective Resource[21]	90	270	450	Medium-High

Table 5-2: 43/7 and 43/8 Carboniferous Play Prospective Resource Assessment

5.3.1 Clachnaharry Lead

The Clachnaharry Lead, as identified by Granby Enterprises,[20] lies within partly within licence P2261 (block 43/7) and extends updip to the west into 43/6 (**Figure 5.6**). It has been mapped as a Rotliegendes sand stratigraphic pinchout towards the edge of the Mid North Sea High. The lead is considered as high risk but, if Rotliegendes sandstone reservoirs can be proven on the licence, the upside is significant. The Rotliegendes and Carboniferous objectives are undrilled on the licence and the nearest well is in 43/6 which encountered the Namurian but no Rotliegendes. The Rotliegendes should be potentially capable to flow economic rates of gas if sufficient thickness of sandstones are developed.

[20] The estimated number of structural traps that are predicted to be identified in this structural setting from extensive good quality seismic data coverage, is assumed to be in the range of 1 to 5 for the Carboniferous.
[21] This is the product of the multiplication of the trap number by the P_{50} resource size. This is equivalent to arithmetically summing the best case values for individual opportunities. This estimate is unrisked.

Clachnaharry is assessed for prospective resources as a lead as it is poorly defined at this stage. Rigorous seismic interpretation and depth conversion, together with sandstone fairway analysis, is required. Such studies will reduce both the play risk and may firm up other drillable Rotliegendes prospects with an acceptable chance of success. The play has not been proven in the area so the risk considers both the play and lead chance of success.

5.3.1.1 Chance of Success

Trap: the structure is mapped on PSTM (pre stack time migration) 3D seismic, originally acquired in 1993 by BP but subsequently reprocessed. Seismic quality is generally good in the Triassic and Zechstein but poor in the Rotliegendes and Carboniferous.

Axis have reviewed the 3D seismic and considers that a viable stratigraphic trap could exist in the area (**Figure 5.7**). A near base Zechstein structural map is available in the Granby relinquishment report[20] indicating a pinch out down dip from the 43/6-1 well; no Rotliegendes section was present and the Zechstein directly overlies Namurian at the BPU. Thick productive Rotliengendes sandstones are present in the Cygnus field, 50 km to the south east. The pinchout of the Rotliegendes between 44/11 and 43/6 is poorly constrained as all the wells between are shallow Triassic tests. However, the seismic data does indicate well defined subcropping events under the BPU and a section, which is probably Rotliegendes, to the east of 43/6-1. Vintage 2D seismic also indicates that a Rotliegendes section is present in the southern part of 43/8. It is therefore probable that a pinchout edge lies within block 43/7 and may lie close to the Mesozoic collapse zone trending SW-NE through 43/7. Imaging in this area is very poor and depth conversion problematic. Any existing depth maps in this zone should be considered with extreme caution and are unlikely to be valid with the existing quality of seismic imaging and velocity modelling.

Structural trapping may also be effective against faults downthrown to the northwest against the regional dip towards the southeast. Such faults are likely, parallel to the SW-NE trending Mesozoic Graben. Early NW-SE faults could also enhance traps along their western margins. Seismic data also indicates a potentially large Carboniferous structure within 43/7 and such traps will require effective intra Carboniferous seals.

Lead Trap Chance = 50%

Reservoir: the Rotliegendes sandstone is a prolific reservoir within the main fairway of the basin. However, in the northern part of the basin, the interval has been considered to be either very thin or developed in a shale facies. The discovery of thick, widely developed Rotliegendes reservoir in the Cygnus field has significantly upgraded the P2261 area. If the sandstones are sufficiently thick they should be of good quality and flow at commercial rates. Carboniferous sandstones may also be present directly below the BPU. The main risk is that the sandstones are too thin with intermittent, localised development, especially close to the Rotliegendes pinchout edge. Waste zones may be present where the Rotliegendes becomes ineffective as a reservoir.

Play Reservoir Chance = 70%

Lead Reservoir Chance = 80%

Seal: the Permian Zechstein evaporates are the proven regional seals in the area. Intraformational seals in the Carboniferous are likely which would be the bottom seal of the stratigraphic trap. It is also probable that there are fault sealing components which may form smaller structural traps. Seal risk is also associated with leakage along faults especially in the area of the Mesozoic Graben. Thief zones are also possible where potential seals along the flanks of the trap are ineffective for gas. The play chance is primarily dependant on the viability of intra Carboniferous seals in the licence area as discussed for block 43/11 to the south (**Section 4.3.1.1**). Success of any drilling on 43/12 to the south, such as on the Andromeda prospect, will reduce the play risk.

Play Seal Chance = 60%

Lead Seal Chance = 80%

Charge: a regional source and effective charge is proven by the Forbes field on block 43/8 and several large fields and discoveries to the south of the licence such as Cygnus, Pegasus and Crosgan. There is a trap specific risk associated with the effectiveness of migration routes, trap fill and gas saturations. The primary source rock is believed to be the Westphalian coal measures that may subcrop to the east of the lead. Moderate distance migration will be required up dip through the Carboniferous and Rotliegendes under the Zechstein top seal.

Play Charge Chance = 100%

Lead Charge Chance = 90%

The risk will be substantially reduced by rigorous mapping, depth conversion and fairway analysis. This work is currently in progress at CNR. The chance of success indicates the chance of a trap in the area. Detailed work is required to optimise a drilling location.

Permian Rotliegendes Play Chance of Success			
Reservoir %	**Charge %**	**Seal %**	**Overall %**
70	100	60	42

Table 5-3: Clachnaharry, Permian Play Risk Assessment

Lead	Play %	Trap %	Reservoir %	Seal %	Charge %	Chance of Discovery %
Clachnaharry	42	50	80	80	90	12

Table 5-4: Clachnaharry, Lead Risk Assessment

5.3.1.2 Rotliegendes Resources

For the purposes of this evaluation, Axis have based the volumetrics on the structural depth map in the Granby Enterprises relinquishment report, which may be considered as a proxy to the base Zechstein top seal.[20] No isopach maps of the Rotliegendes were available and a wide range of area has been considered to account for the uncertainties of mapping and depth conversion. The high case P_{10} area of 50 km^2 is based on the extent of the maximum closing contour at 3110 m on the Clachnaharry depth map (**Figure 5.6**). The low P_{90} area is 10 km^2 at the 2920 m contour. The lead, as mapped, extends into blocks 43/6 and conceivably may extend into 43/11 and 43/12. The areas on block 43/7 are 35 km^2 (high case) and 2.5 km^2 (low case). The range of volumes considers the structural integrity to the spill point together with the fill factor which is linked to effective gas charge.

There is also a good chance that a number of small structural traps will exist formed by the SW and NW trending faults in the area. Detailed mapping may result in a significant refinement of the pinchout edge and the size of potential traps.

The reservoir parameters used for the volumetrics (**Table 5.5**) are based on the wells in the area as described in **Section 5.1.** The net pay considers the Cygnus Rotliegendes thickness which is of the order of 30 m and is taken as the high case. The stratigraphic model assumes that this sandstone will pinchout to zero to give an average net pay of 15 m which is considered as the best case.

The Rotliegendes porosity is likely to be in the range of 6-16% based on Cygnus and analogous wells in the Rotlegendes reservoir.

The gas saturation is based on the typical regional values anticipated in the Rotliegendes assuming an effective charge. The gas expansion factor was calculated from the ranges of temperature and burial depth. The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS.

Clachnaharry Lower Permian Volumetric Input Parameters			
	Low	**Best**	**High**
Net Pay Thickness (m)	8	15	30
Porosity (%)	6	11	16
Gas Saturation (%)	50	60	70
Formation Volume Factor (Gas)	235	245	255
Gas Recovery Factor (%)	40	60	80

Table 5-5: Clachnaharry Lower Permian Lead, Volumetric Input Parameters

The volumetric parameters for the Clachnaharry lead were input into the REP stochastic software and in place and prospective resources were calculated. The mean UPIIP is 266 Bscf gross (146 Bscf on 43/7) of gas and the mean prospective resources are 157 Bscf gross (86 Bscf on 43/7). It is possible that a number of smaller structural trap exist in the area which will potentially have lower trap risk but lower resource potential.

Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 5.6**).

Gas Initially in Place (GIIP) (Bscf)								
Clachnaharry	Total Trap				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Rotliegendes	55	184	571	266	15	76	351	146
Prospective Resources (Bscf)								
Clachnaharry	Total Trap			Net on Licence				
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Rotliegendes	29	105	342	9	43	207		

Table 5-6: Clachnaharry Lower Permian Lead, GIIP[22] and Prospective Resources – Total Structure and Net on Licence

The ratio of the high to low cases (total trap) is large and is of the order of twelve reflecting the significant uncertainties with the current datasets.

5.3.2 Williamson Lead

The Williamson Lead, as identified by Granby Enterprises,[20] lies within block 43/7. It has been mapped as a Triassic sandstone faulted dip closure, updip of the 43/7-1 well (**Figures 5.5 and 5.8**). The play is proven on the licence as the Triassic Forbes field lies in the south of block 43/8. The lead is considered as high risk as several Triassic tests in the area have been unsuccessful and the 43/7-1 may have tested the edge of the closure. The Bunter structures are generally only partially filled due to the tortuous migration pathways through the Zechstein salt and trap modifications post migration. Hence potential may lie up dip of 43/7.

Williamson is mapped as a three-way dip closure and relies on closure against the Mesozoic Graben to the north (**Figures 5.8 and 5.9**). This zone is extremely difficult to interpret due to the complex tectonics and any deep conversion is likely to be suspect without rigorous modelling with PSDM. The Williamson lead is therefore different in structural style than the Bunter fields in the area which are well defined four-way dip closures overlying Zechstein salt pillows (**Figures 5.10 and 5.11**).

[22] The mean GIIP has been added for completeness.

Granby have recognised a possible amplitude anomaly or hydrocarbon indicator (HCI) associated with the crestal part of the structure up dip from the well (**Figure 5.9**). If the seismic anomaly can be identified as an anomaly associated with a gas accumulation then it would considerably de-risk the lead. Further work, including AVO analysis and rock physics studies, is required before this structure can be considered as a drillable prospect.

The reservoirs should be capable to flow economic rates of gas if sufficient gas pay. Williamson is assessed for prospective resources as a lead as it is poorly defined at this stage. Rigorous seismic interpretation and depth modelling and quantitative rock physics is required. Such studies will reduce both the lead risk and may firm up the trap as a drillable prospect with an acceptable chance of success.

Three Bunter exploration wells 43/7, 43/8-1, 43/8-2 have been drilled within the licence area. Only one well, 43/8-1 was successful with the Forbes discovery (**Figure 3.11**). The well was drilled near the crest of a well defined four way dip closure based on legacy 2D seismic. The structure is not fill to spill point.

Several Triassic tests to the south of the licence have been unsuccessful. Most of these were drilled on well defined Triassic salt structures although they may not be crestal tests. Failure is most likely to be because of the lack of migration pathways through the salt. In addition, if pathways exist along faults these faults may not be effective seals at the objective horizon.

43/7-1 lies in a complex area where seismic is difficult to interpret along the flank of the Mesozoic Graben. Axis have reviewed the seismic and considers that the well was drilled some way from the crest and may not be within closure.

Axis have also reviewed the old 2D seismic data around well 43/8-2. It appears that the trap relies on a southerly bounding fault. The fault continues up into the Cretaceous so there would be significant side fault risk even if gas could have migrated through the Zechstein. There is no evidence of salt withdrawal so it is likely that there was not a viable migration pathway from the Carboniferous into the Triassic structure. Only regional maps were available and these do not appear to show a significant structure at the objective. CNR are currently remapping this area from the 2D seismic data.

5.3.2.1 Chance of Success

Trap: the structure is mapped on PSTM (pre stack time migration) 3D seismic, originally acquired in 1993 by BP but subsequently reprocessed. Seismic quality is generally good in the Triassic and Zechstein but very poor towards the northern margin of the Williamson lead within the Mesozoic Graben.

A near Triassic (top Bunter) structural map is available in the Granby relinquishment report (2007)[20] indicating a three way dip closure against the Mesozoic graben updip from 43/7-1 well. The mapped crest is circa 170 m up dip from the well. The trap relies on closure against the Mesozoic collapse zone trending SW-NE through 43/7. Imaging in this area is very poor and depth conversion problematic. Any existing depth maps in this zone should be considered with extreme caution and are unlikely to be valid with the existing quality of seismic imaging and velocity modelling. Axis have reviewed the 3D seismic and considers that a viable fault dependant trap could exist in the area. However, the form and size of the trap, especially along the northern margin, may be modified by rigorous seismic interpretation and velocity modelling within the Mesozoic graben.

Lead Trap Chance = 80%

Reservoir: the Traissic sandstone is a prolific reservoir within the South North Sea Basin. The reservoir parameters are based on the close by 43/7-1 well and so reservoir risk is extremely low. There is a possibility that Bunter sandstones may be downgraded along the edge of the Mesozoic graben due to diagenesis including halite cementation.

Lead Reservoir Chance = 95%

Seal: the Triassic shales and evaporates are the proven regional seals in the area The Middle Triassic Rot member is an effective seal in the absence of significant crestal faulting. Top seal risk is low. The main risk is side seal along faults bounding the Mesozoic graben. Gas migration is required from the Carboniferous and to be effective through areas of salt withdrawal and along faults. Such faults also may have to be a present day effective seal.

Lead Seal Chance = 60%

Charge: a regional source and effective charge is proven by the Forbes field on block 43/8. The primary source rock is believed to be the Westphalian coal measures. The Westphalian is likely to be present in the south and east of the licence but subcrops within the licence. The Namurian subcrops the BPU in 43/6-1 and the Westphalian may be absent from the western part of 43/7.

The main risk is due to effective migration from the Carboniferous, through the Zechstein evaporates into the Triassic. The bounding faults along the Mesozoic graben could be an effective conduit. Validation of the HCI will reduce the risk.

Lead Charge Chance = 60%

The risk will be substantially reduced by rigorous mapping, velocity modelling and seismic imaging especially in the Mesozoic Graben. No seismic rock physics or quantitative analysis of the seismic anomaly was available and probably has not been done. This work is considered essential before the lead can be considered as a drillable prospect.

Lead	Play %	Trap %	Reservoir %	Seal %	Charge %	Chance of Discovery %
Williamson	100	80	95	60	60	27

Table 5-7: Williamson, Lead Risk Assessment

5.3.2.2 Triassic Resources

For the purposes of this evaluation, Axis have based the volumetrics on the structural depth map in the Granby Enterprises relinquishment report, which may be considered as a proxy to the Top Bunter sandstone reservoir.[20] A wide range of area has been considered to account for the uncertainties of mapping, depth conversion and fill factor which is linked to effective gas charge. The high case P_{10} area of 3.5 km^2 is based on the extent of the maximum closing contour at 1520 m on the Williamson depth map (**Figure 5.8**). The low P_{90} area is 1.5 km^2 at the 1450 m contour.

The reservoir parameters used for the volumetrics (**Table 5.8**) are based on the wells in the area. The thickness of the sand decreases towards the north. In well 43/7-1 gross reservoir thickness is circa 35 m and in 43/6-1 it is 29 m. Net to gross also decreases northwards to around 50% in 43/7 with the best sands from the middle to base of the unit. Porosities are circa 20% and in Forbes the porosity is 15-25%.[21]

The gas saturation is based on the typical regional values anticipated in the Triassic assuming an effective charge. In Esmond, Forbes and Gordon, it is in the range of 80-85%.[20] The gas saturation also is discounted due to inerts (mainly nitrogen) commonly found in the Triassic reservoirs in the range of 8-16% and in Forbes it is 12%.[20] The gas expansion factor was calculated from the ranges of temperature and burial depth. The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected within the Triassic in analogous quality reservoirs in the SNS.

Williamson Volumetric Input Parameters			
	Low	Best	High
Net Pay Thickness (m)	10	16	26
Porosity (%)	15	20	25
Gas Saturation (%)	60	70	80
Formation Volume Factor (Gas)	160	165	170
Gas Recovery Factor (%)	60	70	80

Table 5-8: Williamson, Volumetric Input Parameters

The volumetric parameters for the Williamson lead were input into the REP stochastic software and in place and prospective resources were calculated. The mean UPIIP is 33 Bscf gross of gas and the mean prospective resources are 23 Bscf gross. Low (P_{90}), Best (P_{50}) and High (P_{10}) and mean gas in place and prospective resources are tabulated below (**Table 5.9**).

Gas Initially in Place (GIIP) (Bscf)								
Williamson	Total Trap				Net on Licence			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Triassic	14	28	56	33	14	28	56	33

Prospective Resources (Bscf)						
Williamson	Total Trap			Net on Licence		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Triassic	10	20	40	10	20	40

Table 5-9: Williamson Triassic Lead, GIIP[23] and Prospective Resources – Total Structure and Net on Licence

The ratio of the high to low cases is of the order of four reflecting the relatively constrained reservoir parameters.

[23] The mean GIIP has been added for completeness

5.3.3 Carboniferous Play

5.3.3.1 Chance of Success

Reservoir:

In blocks 43/7 and 43/8, the Namurian is predicted to be subcropping the Base Permian Unconformity over most of the area where the lower Westphalian A is absent. It is possible that the Dinantian subcrops the area in the northwest and that younger Westphalian intervals are present in the south east (**Figure 5.2**). The presence of effective Carboniferous Namurian reservoir in the area is confirmed by the Pegasus and Pegasus West discoveries in 43/13b, 10-20 km to the south. Namurian pay was encountered in the recent Pegasus (43/13b-6) and Pegasus West wells (43/13b-7). The best rates were from Pegasus West which tested at a combined rate of 91 MMcf/d from three Carboniferous intervals.

The Namurian sandstone source is to the north along the Mid North Sea High. The Namurian consists of a fluvial deltaic stacked sand and shale sequence and is anticipated to be an effective reservoir with reasonable poroperm qualities. A more distal facies is developed to the south of licence P2261. There is a general coarsening up with basin infilling of widespread delta front sediments and finally to the fluvial deltaics of Millstone Grit. The pattern was of stacked progradational fluvio-deltaic sequences with intercalated marine bands. Many of the sandstones are immature and arkosic rich, especially in the north of the area, and may reduce effective permeabilities. Burial depth also severely effects reservoir quality. Typically top Carboniferous depths are of the order of 3000 m to 3500 m and deepening to 4000 m to the south east and into block 43/9.

The Westphalian is a proven prolific gas reservoir to the east of the block in the eastern part of quadrant 43 and 44 where there are many fields (Ketch, Boulton, Murdoch). On 43/8, the basal Westphalian A will be present over most of the block. The Cavendish and Trent are fields with Westphalian A gas resources. The Westphalian A, typically 400-550 m thick, is composed of fluvial distributary channel facies and lake and swamp mudstones and coals. Distributary channel porosity and permeability in the Trent field are in the range of 5-13 % and 50-60 mD; net to gross is typically 20-40%. To the south and east of licence P2261, the Wesphalian B-C may be present. The interval produces from the Murdoch, Caister and McAdam fields. The facies in the P2261 area is anticipated to consist of sandy coal measures deposited in fluvial, lacustrine and deltaic environments.[10] Regionally, the Caister sandstone is an attractive exploration target.

The Dinantian will be present over all the area. The facies belts generally trend west to east with the more proximal facies to the north. The upper Yordale facies may be developed in a more distal slope facies than in the Breagh and Crosgan areas. The underlying Fell sandstones will be in a braided fluvial sand facies and thick sandstones are anticipated with a high net to gross. However, reservoir quality is likely to be poor over most of the blocks except possibly in the northwest.

It is highly likely that sandstones will be encountered within any trap. However the facies and quality is difficult to predict. The Namurian and lower Westphalian sandstone intervals are very variable and laterally discontinuous. They are generally thin (10-20 m thick) and interbedded with shale units of generally similar frequency and thickness. The lower Namurian appears to have a higher shale content as in Pegasus well 43/13b-6z. The main risk for economic flow rates will be the permeability and connectivity. Reservoir properties, especially permeability, deteriorate with depth. Dissolution of feldspars by early migrant products, such as carboxylic acids, would enhance reservoir properties.

Play Reservoir Chance = 90% (Carboniferous)

Seal: the Permian Zechstein evaporates, and locally also the Silverpit Shales, are the proven regional seals in the P2261 area. Top seal risk for Zechstein is low and hence any traps defined by the BPU will have a very high seal chance of success. The primary risk will be due to lateral seals associated with intra Carboniferous seals subcropping the BPU to form combination traps. Such seals have been proven in the Pegasus area to the south but are difficult to predict and identify on current seismic. Marine bands within the Namurian may be the best seals which should be possible to map and be laterally persistent.

Most of the traps on the block may also be cut by faults and may not seal especially if fault throw exceeds the shale seal thickness. The larger structures are often associated with large faults, and therefore have a greater seal risk. The play has not been tested on the licence and is underexplored in the area. Historically the intra Carboniferous has not been mapped in detail, partly due to the poor quality of legacy seismic within the Carboniferous and, because of the perceived risks associated with Carboniferous seals. The Carboniferous is generally developed in a more proximal facies in the licence than in the Pegasus area to the south so with a greater seal risk.

Thief zones are also possible where the potential seals along the flanks of the trap are ineffective for gas. A thin Rotliegendes sandstone could act as a thief or waste zone. The risk of seal or trap integrity for this play takes account of the top and side seals.

Play Seal Chance = 50% (Carboniferous)

Charge: a regional source and effective charge is proven in the south part of the licence with the Forbes field. Dry gas with low inerts are anticipated to be the hydrocarbon type within the Carboniferous. The primary Westphalian source lies to the southeast with likely migration pathways updip into the southern part of licence P2261. Deeper Namurian and Dinantian source rocks are also present and the Scremerston coals gas kitchen in the area could be a secondary source.

There is a risk associated with the effectiveness of migration routes, trap fill and gas saturations. There is little evidence to prove or disprove if traps are fill to spill point within the Carboniferous although the significant gas accumulations at Pegasus and Cygnus indicate effective charge. All these fields lie along or close to structural highs that would be a focus for regional migration. Charge is a higher risk in the northern parts of the licence further from the Carboniferous gas kitchens.

Play Charge Chance = 75% (Carboniferous),

Trap Potential: Licence P2261 lies to the north of the Cavendish (43/19)-Pegasus (43/13) High trend. Axis has reviewed the seismic and legacy structure maps in the area in the CNR data base. Only part of block 43/7 is covered by a 3D seismic survey and CNR have purchased some vintage 2D data in blocks 43/8 and 43/9.

No significant traps are indicated on the legacy maps at the BPU level over the block. However, there is clear evidence of subcropping Carboniferous events in the area which have the potential to form viable traps analogous to Pegasus. This play requires detailed mapping and rigorous depth conversion by CNR. Halokinensis due to Zechstein salt induces significant lateral velocity changes and hence depth conversion problems in the area (**Figures 5.3 and 5.4**). Detailed velocity modelling is required to effectively quantify trap size.

The Mesozoic collapse zone identified in 42/14 trends SW-NE and transverses block 43/7 (**Figures 5.3 and 5.7**). The seismic is generally poor at the Carboniferous level with an acquisition footprint and it could benefit from reprocessing and eventually new broadband acquisition. Depth migration, together with detailed velocity modelling, will help to unlock the trap potential in this complex structural zone. Any existing depth maps in this area should be considered with caution and are unlikely to be valid given the quality of seismic imaging and velocity modelling. The pre-salt is undrilled on the licence and there is no reason to suggest that viable traps do not exist within the Carboniferous if intra Carboniferous seals are effective. The regional dip and migration pathways towards the north west at the level of the BPU so potential trapping geometries will require intra Carboniferous and /or cross faults to effect closures along the western margins.

The overall play chance of success is 34% and considers the chance of the play to be effective on licence P2261. It is the product of the reservoir, source and seal chance as summarised below:

Carboniferous Play Chance of Success			
Reservoir %	Charge %	Seal %	Overall %
90	75	50	34

Table 5-10: 43/5 and 43/6 Carboniferous Play Risk Assessment

5.3.3.2 Play Resource Assessment

Axis has assessed the play prospective resource size potential for the Carboniferous traps that are predicted to be present in the blocks 43/7 and 43/8.

An economic low case size field is anticipated to be in the range of 5 km^2 and a high case of 50 km^2. These areas define a log normal distribution with a best case of 16 km^2. This is consistent with drillable prospects in the area and the smaller gas discoveries such as Crosgan, and the Pegasus traps.

The Breagh field is believed to have an area in excess of 80 km^2 based on published maps and this is equivalent to the (P_5) case area. The regional maps indicate that the Pegasus North and Pegasus South traps have a maximum area in the order of 50 km^2 and the areas of the Andromeda North and South prospects are consistent with the best case area.

The reservoir parameters used for the volumetrics are based on the Pegasus discovery and the wells in the area. The range of net pay thicknesses considers gross, net to gross and the shape factor. Reservoir quality is very variable ranging from good quality transgressive reworked sands to fine grained clay rich sandstones.

The Pegasus well 43/13b-6z encountered three sandstone gas pay units within the Namurian (**Figures 4.2 and 4.8**). Net pay thickness is nearly 50 m over a 70 m gross column. However, for the gross 500 m interval, the net to gross is reduced to approximately 17% although circa 40% in the upper 230 ft interval. The thickness of pay sandstone will be therefore highly dependent on the interval close to the top carboniferous at the BPU. The average porosity in the pay zone is around 5-14% with an average of 11%. Gas saturation varies between about 75% in the top sandstone to 60% close to the free water level at 11,525 m TVDss. The well was abandoned without testing due to mechanical problems. However, the Pegasus West well (43/13b-7) was successfully tested and flowed at a combined rate of circa 91 MMscf/d from three Carboniferous intervals.

The Crosgan field is believed to have a gross hydrocarbon column in excess of 70 m within the Dinantian.[15] In the Crosgan well, 42/10-2z, the Whitby flowed at 8.6 MMscf/d. The gross sandstone was 30 m thick with 70% net to gross and porosities in the range of 10-12%. The Fell sandstone had no charge and very low porosity.

The gas saturation is based on that found in Pegasus, Breagh and Crosgan. In Pegasus, the petrophysical analysis indicate gas saturations of 40-75%. In Breagh well 42/13-2, the petrophysical analysis indicates gas saturations up to 70% in the good sandstones. In Crosgan well 42/10-2z, saturations have been reported in the range of 50-70% which is considered typical for the Carboniferous play. The gas expansion factor was calculated from the ranges of temperature and burial depths. Traps directly underlying the BPU, are likely to be at depths of 3,000-4000 m.

Compared to block 42/11, the primary objectives below the BPU are likely to be similar but deeper in the south east.

The gas recovery factor has a large range due to the uncertainty of reservoir quality but is consistent with those normally expected in analogous quality reservoirs in the SNS. The recovery at Breagh has been reported at approximately 60%.

The following table indicates a range of possible trap areas, reservoir and fluid parameters based on the regional geological and well information and considering the anticipated parameters at the objective depths on the block.

Carboniferous parameters			
	Low	**Best**	**High**
Area km^2	5	16	50
Net Pay Thickness (m)	10	22	50
Porosity (%)	5	10	14
Gas Saturation (%)	50	60	70
Formation Volume Factor (Gas)	240	250	260
Gas Recovery Factor (%)	40	60	80

Table 5-11: 43/5 and 43/6 Carboniferous Play Indicative Trap Size, Reservoir & Fluid Parameters

A Monte Carlo stochastic simulation was undertaken using the low and high parameters tabulated in Tables 5.11 and the hydrocarbon in place and potential resources estimates are given below:

	Low Estimate Bscf	**Best Estimate Bscf**	**High Estimate Bscf**
Gas in Place	34	155	639
Potential Gas Resources	19	89	381

Table 5-12: 43/5 and 43/6 Carboniferous Play, GIIP and Resource Estimates. for a Typical Carboniferous Trap. Based on the Parameters in Table 3.2.

The reservoir parameters and resource estimates for the Carboniferous play in block 43/5 and 43/6 have been benchmarked against similar Carboniferous fields in the basin.

The Breagh field is believed to have a GIIP in the order of 1190 Bscf consistent with a P_5. Breagh ultimate reserves have been estimated at 700 Bscf.

The Crosgan field GIIP is of the order of 155 Bscf (P_{50} contingent) and 69 Bscf (P_{50} prospective) consistent with the P_{50} or best case. Pegasus North is assessed with gas (2C) resources of over 100 Bscf and Pegasus West with over 70 Bscf[16] consistent with the best case scenario. This assessment is also consistent with the prospective resources in the Andromeda prospect in 43/13 which is mapped on 3D seismic data and is analogous to Pegasus. Best case prospective resources have been estimated as circa 80 Bscf on each of the Andromeda North and Andromeda South traps.[16]

It is anticipated, considering the structural style in the Carboniferous, that several small traps may exist on the block. To assess the exploration resource potential in the block, Axis have estimated the possible average trap density for the Carboniferous plays. We have assumed the density will be approximately 1-3 structures (based on an assumed most likely trap area of 16 km^2) for a typical North Sea block in the mature area of the Southern North Sea. This density may be reduced towards the flanks of the basin and the evaluation of block 43/7 has also considered a Rotliegendes pinchout play which may be mutually exclusive to the Carboniferous play. A range of 1-5 structures have therefore been considered for the two blocks 43/7 and 43/8.

Based on the assumptions described above, a prospect portfolio would be expected to have an average resource size expectation equivalent to the best estimate or P_{50} value which is estimated to be 90 Bscf for the Carboniferous play.

This value, together with the estimated number of prospects that would be expected in this type of structural setting and block size, can be used to estimate an un-risked arithmetically summed prospective resource potential for a prospect portfolio as summarised in the **Table 5.13** below:

Carboniferous Play	Low (MMbo)	Best (MMbo)	High (MMbo)	Play Risk
Assumed Trap Number[24]	1	3	5	
Total Prospective Resource[25]	90	270	450	Medium-High

Table 5-13: 43/5 and 43/6 Carboniferous Play Prospective Resource Assessment

[24] The estimated number of structural traps that are predicted to be identified in this structural setting from extensive good quality seismic data coverage, is assumed to be in the range of 1 to 3 for the Carboniferous.
[25] This is the product of the multiplication of the trap number by the P_{50} resource size. This is equivalent to arithmetically summing the best case values for individual opportunities. This estimate is unrisked.

If the play is proven on block by an exploration well, the potential on licence can be very significant. Assuming approximately three potential traps, and the best estimate resource value, the total unrisked prospective resources could be in the range of 270 Bscf.

The play chance of success does not take into account any prospect related risks. The prospect chance of success considers prospect specific risks for trap, seal, reservoir and charge. This play is considered to be medium-high risk; it is possible that given a well-defined structure based on good quality seismic, that the prospect chance of success may be in the range of 10-20% for the Carboniferous play.

5.4 Additional Potential

The 3D seismic covers approximately 50% of block 43/7, essentially in the central area traversed by the Mesozoic graben. The two leads assessed have been on block 43/7 and were summarised in the relinquishment report.[20] The evaluation by the previous operator was limited to the area of the 3D seismic data. There is considerable potential for traps in the other parts of the licence.

The area requires detailed mapping and rigorous depth conversion by CNR. Halokinensis due to Zechstein salt induces significant lateral velocity changes and hence depth conversion problems especially in the area of the Mesozoic graben. Detailed velocity modelling is required to effectively quantify trap size.

Seismic imaging of the objective Carboniferous is extremely poor in this area. Any existing depth maps in this area should be considered with caution and are unlikely to be valid given the quality of seismic imaging and velocity modelling. Reprocessing, and eventually the acquisition of new broadband 3D, will be necessary to fully evaluate the licence.

The Rotliegendes development in the licence is unknown but the discovery of the Cygnus field has enhanced the possibility that conventional Rotliegendes traps exist in the area. Fault traps are possible especially where both the north-west and north-east trending faults are effective seals.

Most of block 43/9 is not considered as this area is subject to a planned offshore windfarm and therefore not been fully assessed until the impact of the windfarm on the potential to explore and develop hydrocarbons is known. However, it is possible that the Rotliegendes and Carboniferous plays described elsewhere extend into the eastern part of licence P1261. The southern part of this block may be available for exploration in future.

6.0 PETROPHYSICS REVIEW

The petrophysical analysis related to this report is based on a review of previous analyses given in a number of block, related reviews by various Operators and other providers from the Service Sector. These relate, but not limited to, existing CPR's, relinquishment documents, promote documents and any other relevant data, including offset data, reviews and relevant published literature provided by CNR and located by Axis. At this stage, no attempt has been made to create a petrophysical database from scratch that covers all the licences under review, and perform detailed petrophysical analyses, though certain data, e.g. core data and temperature data, was reviewed in more detail to assist in any relevant analysis. It was considered that due to the time allocation given to the petrophysical element in this CPR, the time would be better served reviewing existing data though it is certainly recommended that such a database be compiled that will allow more exhaustive studies to be undertaken which can only benefit the understanding of the area from a reservoir characterisation perspective.

It must be stated that all the reservoirs under review have certain analysis challenges that relate somewhat to data issues, namely, vintage, quality- both due to hole conditions and data types and reservoir focus, and at this stage, availability of certain data for this review. Couple these data issues with questions surrounding the potential reservoir quality of certain formations under review, make for a difficult assessment. In addition this review dealt with a number of different reservoirs, both in age and type that require different petrophysical techniques and focus that compounded the difficulty with the analysis.

In age order from the youngest to the oldest formations a brief review of the key issues surround the plays from a petrophysical perspective are given below. In this section there is no attempt to indicate reserve parameter values for each of the formation, but rather the key elements that make the play, or issues surrounding the play, from a petrophysical point of view.

The Triassic Bunter Formation is the youngest formation under review and can comprise a thick (circa 400 ft) sequence of interbedded fine grained sands, silts and shales that has been a prolific formation in the early years of the UK's SNS gas production.

Production has been from a number of fields, with the Forbes-Esmond-Gordon complex, operated initially by Hamilton Bros Oil and Gas, as well as smaller Bunter aged accumulations in the Hewett Field and the Little Dotty Field. The Bunter sands can have relative good petrophysical volumetric parameters, porosity values above 20%, with low water saturations <20% and high NTG around 80%. However the main complication with the Bunter Sandstone Formation is the presence of varying quantities of halite cement that can occlude the porosity, causing problems with any subsequent petrophysical analysis.

The Permian, Zechstein Plattendolomite (Z1) and Hauptdolomite (Z2) are also potential reservoirs in the area and consist of carbonate reservoirs whose reservoir quality is determined by a combination of depositional facies and diagenesis, coupled with increased porosity and permeability as a result of collapsed breccias and associated fractures. Matrix properties can be quite poor, but due to the fractured nature of the reservoir, production is observed in the Hewett Field as well as numerous other offshore SNS fields, as well as onshore Germany, Netherlands and the UK. As stated earlier, the main issues with these formations is the low matrix volumetric properties, which can be affected further by halite and anhydrite diagenesis, especially in the Plattendolomite.

No analysis or review of the Permian Rotliegendes reservoir in the area was undertaken. Distribution of any potential reservoir in the CNR licences is questionable and therefore no detailed review was considered in this CPR. However, it is considered that any potential Rotliegendes reservoirs will have sufficient reservoir quality to allow commercial production rates to be achieved.

The Carboniferous Westphalian and Namurian reservoirs underlying the Permian reservoirs are also present in the area and a number of wells in the area have tested from a number of different sandstones in the Carboniferous. In addition, gas fields in the area, like Breagh, Cygnus and Pegasus, produce from Carboniferous sandstones at commercial rates.

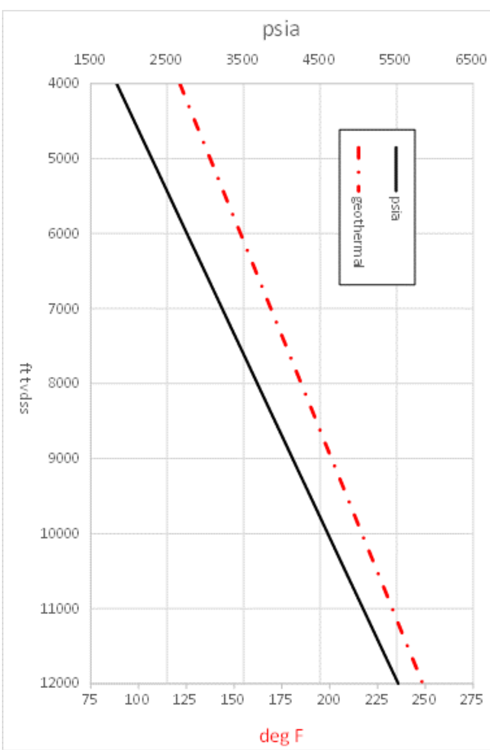
Reservoir properties for the Carboniferous as a whole can be quite variable, but generally the sands have low porosity <10% with associated low permeability and high water saturation and will need to be stimulated to allow commercial production to be derived. However, certain sands in the section, exemplified by section in the Breagh and Cygnus Fields have moderate to good reservoir properties, with porosity values <15% with good permeabilities and low water saturations.

As a result, it is recommended that in any future drilling plans, and subsequent data acquisition programmes focus on delivery of quality products that allow for accurate reservoir assessment. This includes safe, rock/fluid compatible drilling practices that will deliver quality hole sections. This will allow the acquisition of both core and hi-end wireline data to address the individual reservoir issues and to allow critical assessment studies to be accurately determined.

7.0 RESERVOIR ENGINEERING REVIEW

There are two main reservoir engineering inputs to this report: for each geological prospect/play, (1) to provide a gas volume factor to convert reservoir volumes to standard surface conditions, and (2) to indicate a gas recovery factor to estimate recoverable volumes for a given gas-in-place (GIIP) volume. As all the GIIP volumes are prospective, a range of low, best and high values are required for each of the ten potential developments.

All gas formation volume factors (FVF) are a direct function of the Z-factor (compressibility factor) in the equation which links pressure, volume and temperature for real gases (PV=ZRT). Given a pressure and temperature of a subsurface gas accumulation, it is therefore possible to derive the FVF for a given Z-factor, where the Z-factor depends on the gas composition. The anticipated subsurface depth of each of the ten potential gas accumulations has been used to derive an appropriate pressure and temperature. A normal water gradient of 0.46 psi/ft gives a pressure estimate and a geothermal gradient gives an estimate of temperature (**Figure 7.1**). There is a wide range of depths for the ten prospects, circa 4000 – 12000 ft, so the FVF's cover a wide range (**Figure 7.2**).



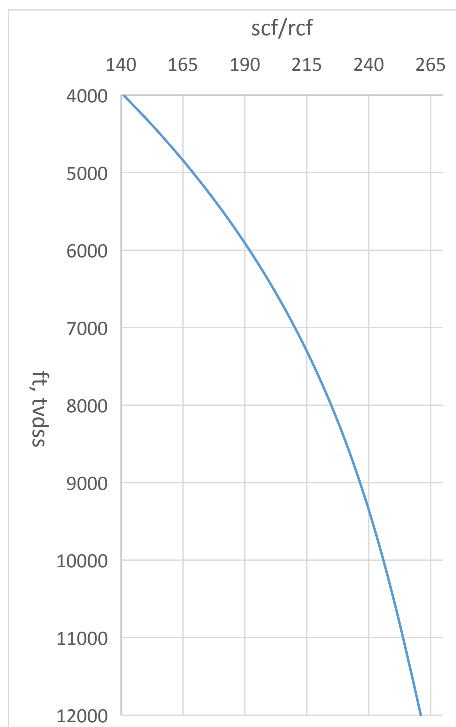


Figure 7.1: Reservoir pressure and temperature with depth,

Figure 7.2: FVF with depth

A gas composition with a high methane content has been assumed (SG 0.63) and a suitable correlation used to estimate Z-factor at various reservoir pressures and temperatures. Z-factors for an alternate composition with less methane and more carbon dioxide and nitrogen (SG 0.75) have also been generated to investigate the likely range of FVF at each depth. Accuracy of the estimated FVF is considered to be to two significant digits, for example at -6000ft, the estimated FVF is 190 scf/rcf. Given the possible variation in gas composition, and accuracy of the depth related pressure and temperature, a low value at -6000 ft would typically be 180 scf/rcf and a high value 200 scf/rcf.

The second required input is a range of gas recovery factors (RF) and these cannot be calculated so readily. Much effort goes into evaluating RF for producing fields, the resulting RF * HCIIP giving the “Estimated Ultimate Reserves” (EUR), a key parameter for reservoir management. A high value for gas reservoirs is typically considered to be 80%. Additional investment to recover more than 80% of the GIIP would need careful evaluation. In a tank model of a gas reservoir with no water influx, the ultimate recovery is simply a factor of how low the reservoir pressure can be drawn down, as a conventional P/Z plot would show. Additional investment in surface gas compression, in order to continue exporting gas while continuing to deplete the reservoir, is a common strategy, for example the Breagh field will require such investment in the near future. Without this, RF will be significantly lower; however it is important to realise that RF is only an intermediate value, the number which is actually important is the ultimate reserve. When the volume of recovered gas from some fields is compared to the reported GIIP, the calculated RF can be much higher than 80%, but this may be because the reported GIIP was too low (eg Hewett Field reservoirs with >95% recovery).

On the other hand, RF will be very much lower if water enters producing wells and reservoir pressure fails to lift wellbore fluids. RF may easily drop to <40% in such cases. Early water breakthrough may occur unpredictably in heterogeneous reservoirs. Compartmentalisation of the GIIP volume may be another cause of low recovery. Drilling more wells to access undrained compartments may not be economic. Breagh’s development plan calls for a second stage in which a second well cluster is required to access a more remote part of the field, such later investment may not be uneconomic.

Estimated RF’s for contingent and prospective assets are used to gauge ultimate potential reserves, and if these resource categories in future move to development, then the volumes to be produced will be subject to what is economically producible. Many factors then come into play such as available gas market, infrastructure to deliver the gas to market, gas price, gas transport costs, sales gas quality constraints, etc. For instance Breagh gas has some CO_2 and N_2 but benefits from being mixed with neighbouring produced gas that dilutes these contaminants to within export specification.

Since it is impossible to factor in actual economic constraints for assets not yet at the development stage, any value assigned to RF will necessarily need to be a gross estimate. For the prospects/plays under consideration here, the range of low-best-high is given as 40% -60% -80%.

A distinction could be made between the Zechstein carbonates and the Carboniferous sandstones where there is a likelihood of lower RF's for the carbonates. For the Zechstein Hauptdolomite and Plattendolomite, production depends on the nature and extent of natural fracturing. Although hydrocarbons have been found in several neighbouring prospects, testing has generally been disappointing with low and rapidly declining gas rates. The Zechstein has been produced at Hewett from sweet spots which have extensive natural fractures.

There is also the Wissey Field (53/4d) which has been produced by Tullow with a single subsea well tied back to facilities at a Thames platform via Horne & Wren. This well produced 18.2 Bscf from the Plattendolomite from 2008 for a period of 40 months. The production history is shown in **Figure 7.3**. The operator Tullow in the decommissioning report state that gas recovery was 65%. This is based on a GIIP of 28 Bscf. However, in 2008 a joint venturer Faroe Petroleum with a 18.75% interest were estimating 5.9 Bscf reserves (equating to full field 31.5 Bscf) with "potential for further upside". Evidently Faroe were calculating a much higher GIIP than 28 Bscf. This value is not reported, however if at the time a 65% RF was anticipated, GIIP would have been 48 Bscf. Taking this as the GIIP, the actual 18.2 Bscf produced equates to a RF of 38%. This highlights the uncertainty in estimating GIIP in a dual porosity system where gas is located in the carbonate matrix and in the fractures.

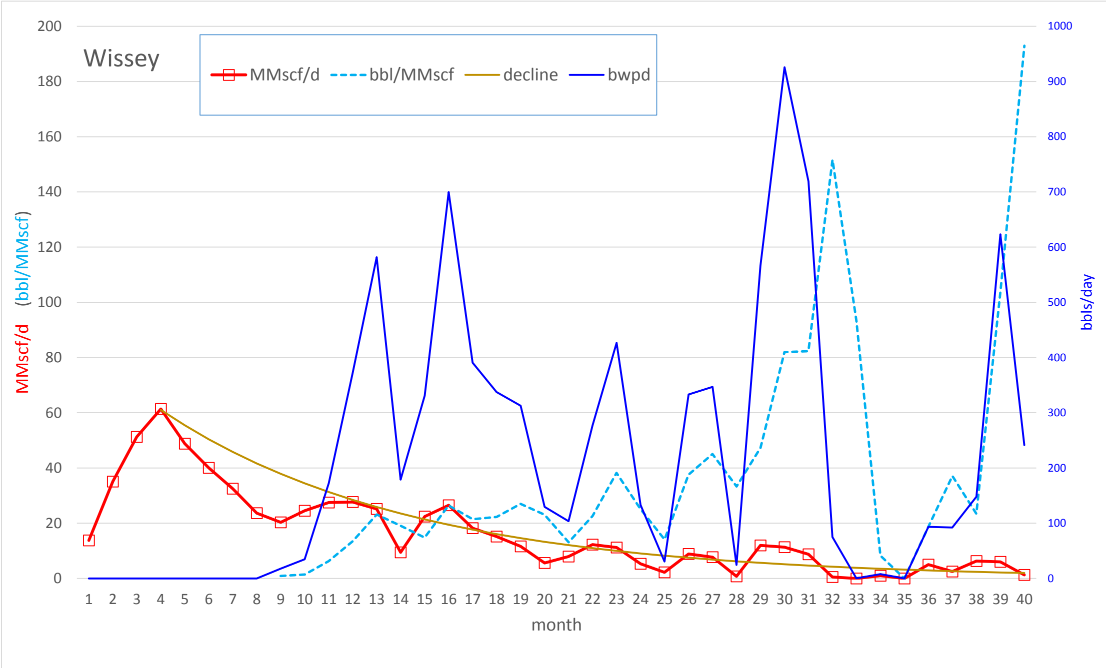


Figure 7.3:Wissey Field production data (DECC)

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Analysis of fractures yields improved gas production from Zechstein carbonates, Hewett Field, UKCS. Piers Cooke- Yarborough

8.0 PRODUCTION OPTIMISATION REVIEW

8.1 Carboniferous

Of the producing analogue Carboniferous reservoir developments in the SNS, Breagh provides the most recent and comprehensive example of the trends and outcomes in well production optimization.

Owing to the drilling risks posed in the overburden (primarily salt and Zechstein carbonates), the well casing designs allow for a contingency 6” hole in the reservoir and the option for a deep sidetrack: these are standard designs for this area.

The completion across the reservoir is cased and perforated. No downhole sand control is required: the formations are competent under lifecycle pressures.

Well deviations across the reservoir section are limited to 65^o in order to:

- Reduce the potential effect of the positional (lateral and depth) uncertainties of the reservoir sand bodies.
- Contact all the sands within the target zones for production.
- Increase reservoir/wellbore contact (compared with a vertical well).
- Aid drilling stability, which reduces at higher angles.
- Allow for standard wireline re-entry (no tractors required).

The completion tubing sizes are selected to provide the highest rate with the longest stable flow conditions with liquid loading, and flowing velocities below the tubing erosion limits. Inflow performance is normally assessed across the tubing size range 3.5”, 4.5” and 5.5”.

Particular points to note for well production performance are:

- The Carboniferous sands are known to be prone to formation damage owing to high over balances when drilling the reservoir.
- The reservoir permeabilities range from 1 mD to 1 0mD.

Production optimization is focused on:

- Extensive testing and selection of the reservoir drill-in fluid to minimize formation damage and minimizing the formation damage related skin.

- Utilising deep penetrating perforating charges to penetrate beyond the damage zone.

- Applying underbalance to provide clean perforations.

The Breagh wells were perforated with a combination of static and dynamic underbalance on wireline with thru-tubing guns. The static underbalance was limited to a maximum of 500 psi which is considered insufficient to adequately clean the perforations in tight gas sands. The dynamic underbalance systems will generate a short duration underbalance of several thousand psi. During well clean-up, the highest feasible drawdowns were applied to aid perforation flow.

For analogous Carboniferous reservoirs, the overall well performance is variable and dominated by permeability differences between the potential productive sands. Encountering lower than expected permeabilities is particularly detrimental and not improved by the well completion flow performance. Optimization strategies used include limiting formation damage and optimizing the perforation geometry. The completion strategy for these wells is being fundamentally altered to incorporate propped hydraulic fracturing. Initially, hydraulic fracturing has been used on the lower permeability zones. A fourfold to tenfold increase in flow rate has been reported for wells (over that expected if not stimulated). The treatments also have increased field reserve estimates. Fracture stimulation of these reservoirs should be considered standard for future wells.

The Breagh hydraulic propped fracture stimulations were carried out from a purpose design frack vessel (Schlumberger's Big Orange). Multi-service vessels, with a land frack spread, have been used by different operators in the area. The treatments add to well costs but the reported well performance improvements are significant. Well planning is also affected by the availability and scheduling of fracture stimulation services (vessels).

8.2 Zechstein Dolomite

Zechstein dolomite reservoirs have been produced for many years, mainly, as a secondary target by perforating (vertical) wells when production from the underlying Carboniferous sandstone reservoirs had ceased. The dolomite is tight and production is from the natural fractures present. Good productivity is dependent on intersecting as many of the fractures as is possible. Overview map in figure 8.1.

Wells in the Dalen field (onshore Netherlands, NAM) target the Zechstein Dolomite and vertical wells showed generally poor productivity. The productivity impairment associated with standard drilling and completion methods are:

Massive losses to fractures making continued drilling difficult.

Significant formation damage and consequential production impairment caused by:

Insufficient fractures penetrated.

The large scale contamination of the fracture system with drilling fluid.

A horizontal well drilled to intersect the fracture network gave significant production improvements but was technically difficult and expensive owing to the massive losses of drilling fluids to the first intersected natural fracture system and drilling problems that this initiated. As a consequence, a single trial horizontal well was drilled in 1995 using underbalance and coiled tubing drilling. The well was drilled through two discrete fracture systems and production was significantly greater than that from the vertical wells. The technique was considered a technical success but requiring further development.

A two-well project in the Coevorden Zechstein field (onshore) trialed boundary element code to predict fracture distribution and coiled tubing underbalanced drilling. The operations were challenging: sour gas, deep, high pressure and temperature, high flow rates. Operational performance was good with a total of 1040 m of reservoir drilled in three separate lateral legs.

Gas flow rates exceeding expectations and rates progressively increased with the number of intersected fractures.

Underbalanced drilling has been taken offshore for several operations (see Figure below). The operation is more challenging in the offshore environment and subject to stringent regulatory control. The use of underbalance drilling is not commonplace and requires a significant amount of planning and training before implementation.

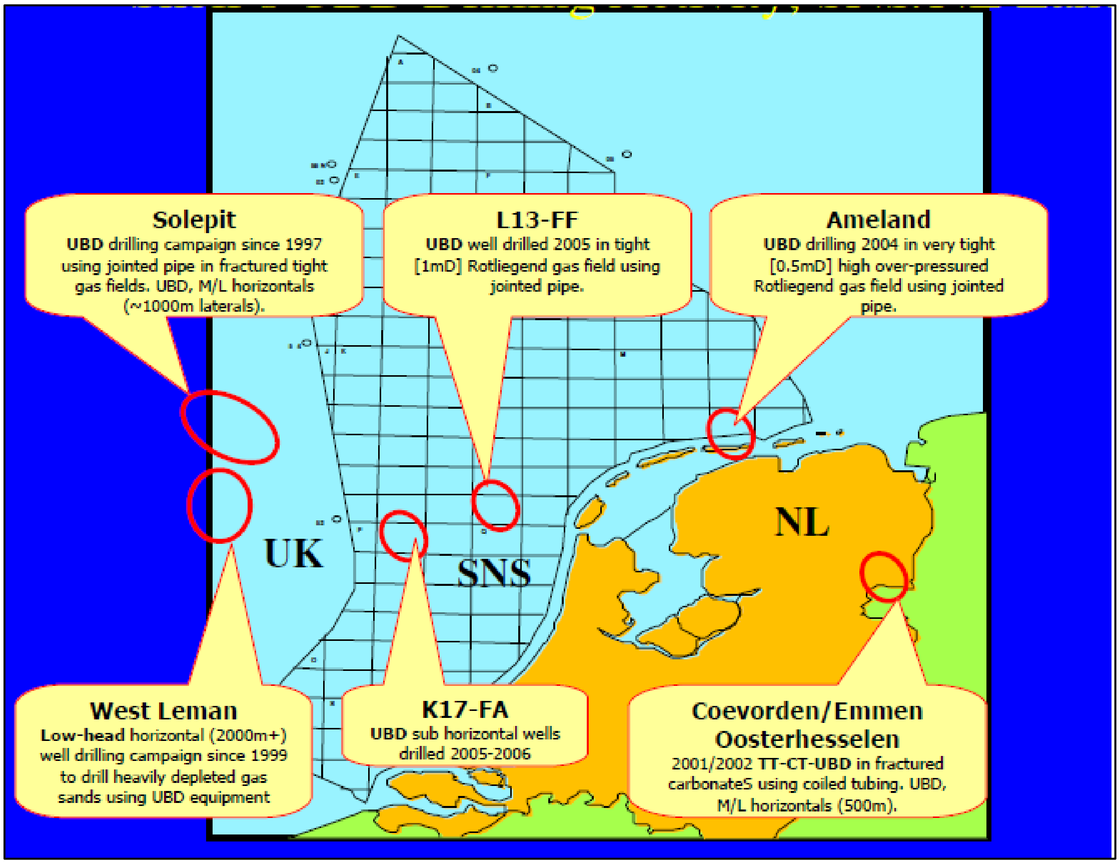

Figure 8.1 Zechstein Play Overview

As with the Carboniferous formations, fracture stimulation (in this case acid fracturing) may provide an alternative to underbalance drilling as a method of intersecting the natural fracture system, but is dependent of the orientation of the system to the local field stresses. If the orientations of the natural fractures and well stimulation fractures were favourable, then this technique is well developed and would be technically simpler and lower cost than underbalanced, horizontal, coiled tubing drilling. Good natural fracture distribution modelling would confirm the applicability of fracture stimulation.

9.0 CLASSIFICATION OF RESOURCES

Classification of resources has been assessed using the PRMS definitions and terminology (**Appendices 2 and 3**).

The resources in this report are considered as prospective resources.

Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity (**Figure APP1-2, Appendix 2.2)**.

In this CPR, the prospective resources have been assessed at the prospect, lead or play level.

Contingent Resources	*Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.*	*Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.*
Prospective Resources	*Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.*	*Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.*
Prospect	*A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.*	*Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.*

Lead	*A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.*	*Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.*
Play	*A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define*	*Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.*

In licence P2252, two prospects have been identified. Lytham and Fairhaven have been drilled but testing and logging did not establish the existence of a significant quantity of potentially moveable hydrocarbons due to mechanical problems and hole quality issues. They may therefore not be considered for contingent resources and a risk has been assessed which is the chance or probability of the prospective resource maturing into a contingent resource. The traps are sufficiently well defined to represent viable drilling targets.

In licence P2252, one lead (St Anne's) has been identified and in licence P2261, two leads have been identified (Clachnaharry and Williamson). The leads are currently poorly defined and require more data acquisition and evaluation in order to be classified as a prospect.

In licences P2248, P2253 and P2261, the Carboniferous play has been assessed. The play is associated with a prospective trend of potential prospects but which requires more data acquisition and evaluation in order to define.

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APPENDIX 1: PERSONNEL

Name	Personal Profile Statements
Dr Martin Eales	**Principal Geoscientist** with a strong record of achievement and extensive experience of international exploration and development projects with major operators and independents. A working knowledge of most petroleum basins in the world with specialised experience in the North Sea, Europe, FSU, the Middle and Far East. Also a specialist in Reserves and Resource Assessments, Due Diligence and Competent Person Reports. 37 years industry experience. PhD in Geology from University of Glasgow. MA in Natural Sciences from University of Cambridge. Publications include 'Nature'; 'London Geological Society' and various symposium volumes. Fellow of the Geological Society of London (FGS), Member of the European Association of Geoscientists and Engineers (EAGE), and the Petroleum Exploration Society of Great Britain (PESGB).
Mr Andrew Foulds	**Principal Petrophysicist** with over 35 years' international experience in reservoir evaluation, working both in the service sector and within international oil companies. Key skills include planning cost effective integrated Petrophysical programmes for all types of reservoirs including unconventional resources, tight gas, shale source rock places, shale gas and shale oil as well as CBM. Extensive operational and project execution experience in various locations, both onshore and offshore, including wellsite support and geosteering. BSc (Hons) in Geology from Hull University.
Mr Peter Aldersley	**Principal Reservoir Engineer** with over 30 years' experience and a successful record in various operating companies and consultancies. Includes widespread experience of data collection and analysis: particular strengths in reservoir simulation, well testing and pvt analysis, production forecasting and reserves evaluation; team player with a flair for problem-solving; using to delivering detailed accurate well-documented work to deadlines. BSc (Hons) in Geology from University College of London. MSc in Petroleum Engineering from University of Texas in Austin.

Mr Karl Bird	**Principal Engineer** with over 26 years oilfield experience in platform rigs on exploration and development wells; project leader of a well engineering technology programme with responsibility for all aspects of well engineering technology but with particular expertise in completions, stimulation, perforating, sand production and well/completion related risk assessments. BSc (Hons) in Mining Engineering from University of Newcastle upon Tyne. Member of the Institute of Materials Minerals & Mining.
Dr Katrine Holdoway	**Principal Geologist** and Peer Review with a wide knowledge of North Sea and NE Atlantic margin plays; co-author of competent person reports for assets in western Europe, Turkey and Atlantic. Over 30 years extensive experience of hydrocarbon systems analysis, estimation of hydrocarbon potential and risk assessment. Successful track record in evaluation and ranking of acreage for licensing round applications, licence work, acquisition and disposal. PhD in Geology from University of Kansas. BSc (Hons) from University of Exeter. Member of Geological Society of London (FGS), AAPG (American Association of Petroleum Geologists) and PESGB (Petroleum Exploration Society of GB).
Mr Alastair Dodds	**Axis Engineering Director** responsible for production technology and petroleum engineering teams including design, allocation of resources, planning and execution of subsurface studies, exploration and field development. Over 30 years' experience. BSc (Hons) in Geology from St. Andrews University.
Mr Max Harper	**Axis London General Manager** with both a technical and commercial background of numerous multi-national and multi-disciplinary subsurface projects in several countries. 20 years industry experience. Published researcher into Salt Tectonics at London University; MSc Applied Geophysics from Birmingham University and BSc (Hons) in Geophysics and Planetary Physics from Newcastle University; MBA from the Open University.
Ms Andrea Lovei	**Senior Reservoir Engineer** with over 14 years' experience gained with operating company and various consultancies. Includes extensive knowledge and experience with optimization of mature fields, forecast production and reserve estimation and well performance, data collection and analysis, PVT analysis, reservoir characterization, material balance calculations, numerical reservoir simulation; strong technical knowledge and understanding both classical reservoir engineering and numerical modeling. MSc in Reservoir Engineering from University of Miskolc (Hungary).

APPENDIX 2: PRMS STANDARD DEFINITIONS

The following italicised text is reproduced from the Petroleum Resources Management System (2007).

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

***Figure APP1-1** is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum*

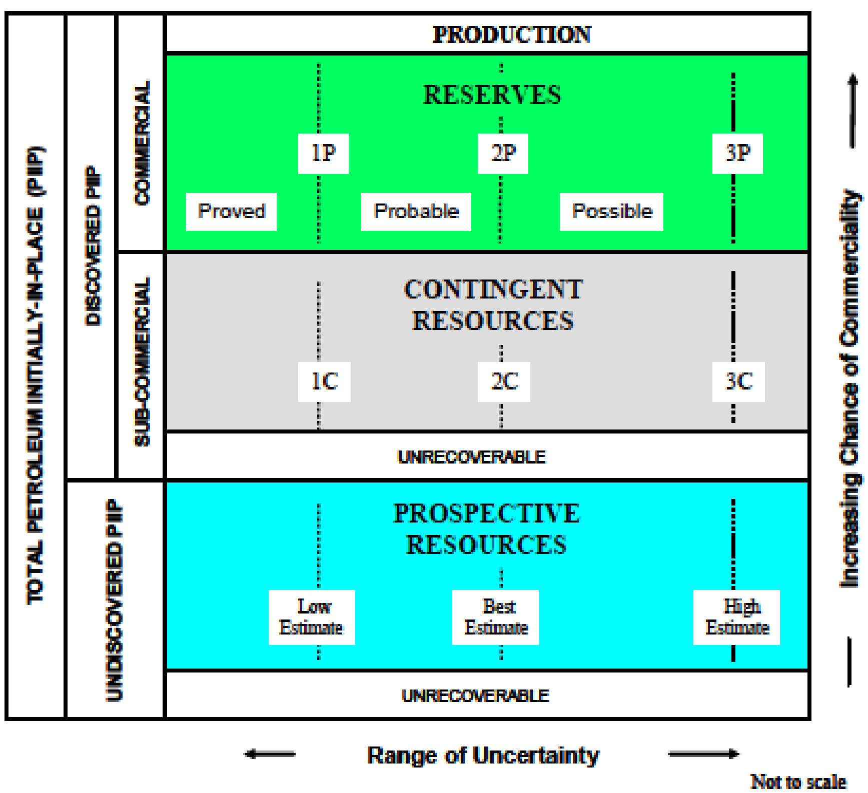


Figure APP1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE *is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").*

DISCOVERED PETROLEUM INITIALLY-IN-PLACE *is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.*

PRODUCTION *is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.*

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES *are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.*

CONTINGENT RESOURCES *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.*

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE *is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.*

PROSPECTIVE RESOURCES *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.*

UNRECOVERABLE *is that portion of Discovered or Undiscovered Petroleum Initially-in- Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.*

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- *Evidence to support a reasonable timetable for development.*
- *A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:*
- *A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.*
- *Evidence that the necessary production and transportation facilities are available or can be made available:*
- *Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.*

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- *The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."*
- *Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."*

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 Project Maturity Sub-Classes

*As illustrated in **Figure APP1-2**, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.*

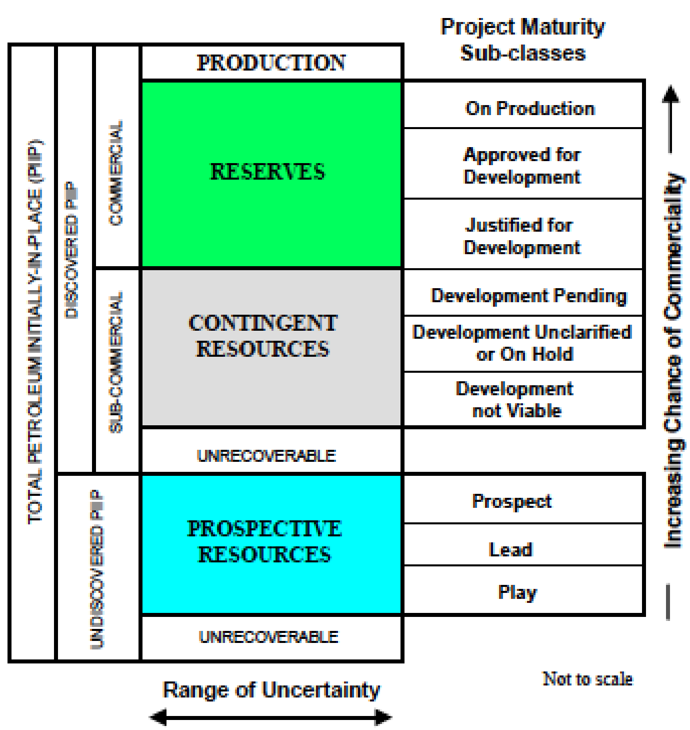


Figure APP1-2: Sub-classes based on Project Maturity.

Table APP1-1: Recoverable Resources Classes and Sub-Classes

Class*/Sub-Class*	***Definition***	***Guidelines***
Reserves	*Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.*	*Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status.* *To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame.* *A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.* *To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon- bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.*
On Production	*The development project is currently producing and selling petroleum to market.*	*The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%.* *The project “decision gate” is the decision to initiate commercial production from the project.*
Approved for Development	*All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.*	*At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget.* *The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.*

***Class**/Sub-Class*	***Definition***	***Guidelines***
Justified for Development	*Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.*	*In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class).* *The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.*
Contingent Resources	*Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.*	*Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.*
Development Pending	*A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.*	*The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status.* *The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.*

Class/*Sub-Class*	***Definition***	***Guidelines***
Development Unclarified or on Hold	*A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.*	*The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status.* *The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.*
Development Not Viable	*A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.*	*The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.* *The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.*
Prospective Resources	*Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.*	*Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.*
Prospect	*A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.*	*Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.*
Lead	*A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.*	*Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.*
Play	*A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.*	*Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.*

Table APP1-2: Reserves Status Definitions and Guidelines

Status	***Definition***	***Guidelines***
Developed Reserves	*Developed Reserves are expected quantities to be recovered from existing wells and facilities.*	*Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.*
Developed Producing Reserves	*Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.*	*Improved recovery reserves are considered producing only after the improved recovery project is in operation.*
Developed Non-Producing Reserves	*Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.*	*Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.* *In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*
Undeveloped Reserves	*Undeveloped Reserves are quantities expected to be recovered through future investments:*	*(1) From new wells on undrilled acreage in known accumulations, from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.*

Table APP1-3: Reserves Category Definitions and Guidelines

Category	*Definition*	*Guidelines*
Proved Reserves	*Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.*	*If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.* *The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and* *(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.* *In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8).* *Reserves in undeveloped locations may be classified as Proved provided that:* • *The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive.* • *Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.* *For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.*
Probable Reserves	*Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.*	*It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.* *Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.*

Category	*Definition*	*Guidelines*
Possible Reserves	*Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.*	*The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.* *Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.* *Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.*

Probable and Possible Reserves	*(See above for separate criteria for Probable Reserves and Possible Reserves.)*	*The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.* *In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.* *Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.* *In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.*

APPENDIX 3: NOMENCLATURE

Abbreviation	Description
1P	Reserves of the “proven” level; generally taken to be the 90% confidence level of the probability distribution; also termed “P_{90}” reserves
2P	Reserves of the “proven and probable” level; generally taken to be 50% confidence level of the probability distribution; also termed “p50” reserves
3P	Reserves of the “proven and probable and possible” level; generally taken to be 10% confidence level of the probability distribution; also termed “P10” reserves
4C-OBC	Four component Ocean Bottle Cable
A	Archie constant
AFE	Application for Expenditure
Ahbdf	Along Hole Below Derrick Floor
AHL	Amerada Hess Limited
API	Oil gravity at 60F in degrees API
API	Oil density in degrees API
API	American Petroleum Institute
AQC	Annual contract quantity
ARP	Asset Reference Plan
Av0	Amplitude versus offset
B or bbls	Barrels
Bbl	US barrel
Bbl/d	Barrels of liquid per day
BCF	Billions (one thousand million) of cubic feet
Bg	Gas volume factor
BHP	Bottom Hole Pressure

BHFP	Flowing Bottom Hole Pressure
BHS	Bottom hole sample
Bo	Formation volume factor
Bo/d	Barrels of oil per day
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
BPV	Bittern pore volume
BS&W	Base sediment and water
BSCF	Billions of standard cubic feet
Bscf	Billions of standard cubic feet
BW/d	Barrels of water per day
Bwpd	Barrels of water per day
CGR	Condensate gas ratio
CIIP	Condensate initially in place
CITHP	Closed in Tubing Head Pressure
CMC	Carbo-Methyl Cellulose mud viscosifer
CNL	Compensated Neutron Log
CO2	Carbon Dioxide
Cr	Crome
CST	Coring Sidewall Tool
DCQ	Daily contract quantity
DHSV	Downhole Safety Valve
DST	Drill Stem Test
DTI	Department of Trade and Industry

EGP	External Gravel Pack
EMV	Expected monetary value; the sum of the net present value of each possible investment outcome multiplied by the probability of its occurrence. In the content of exploration field plus mean success NPV times the probability of a commercial discovery
Expectation	The mean of probability distribution
FCP	Fracture Closure Pressure
FDC	Formation Density Compensated
FDP	Field Development Plan
FIT	Formation Integrity Test
FIV	Formation Isolation Valve
Fm	Formation
FPSO	Flowing Production Storage & Offloading Vessel
Ft	Feet
FTHP	Flowing Tube Head Pressure
FTHT	Flowing Tube Head Temperature
Ft MDBRT	Feet measured depth below rotary table
Ft TVDss	Feet true vertical depth below sea level
FWL	Free Water Level
GIIP	Free gas initially in place
GJ	Gigajoule (10_9 joule)
GOC	Gas oil contract
GOR	Gas oil ratio
GR	Gamma Ray
GRV	Gross Rock Volume
GSA	Gas sales agreement
H_2S	Hydrogen Sulphide

HC	Hydrocarbon
HHV	Higher heating value; heat produced by complete combustion of gas and condensation of water formed
HSE	Health, safety and environment
ID	Inside Diameter
IGP	Internal Gravel Pack
II	Injectivity Index
IIP	Initially in place
IPP	Independent power producer
IPR	Inflow Performance Relationship
IRR	Internal rate of return; the discount rate at which the net present value is zero
K	Seismic velocity factor
K	Permeability
Kh	Permeability time thickness product (in MD. Ft)
Km	Kilometer
km^2	Square kilometer
Krg	Relative permeability for gas
Krog	Relative permeability for oil (in oil/gas system)
Krow	Relative permeability for oil (in oil/water system)
Krw	Relative permeability for water
k_v, kh	Vertical, horizontal permeability
LF	Load factor – ratio of DCQ/MDQ
LGR	Load grid refinement
LOI	Letter of Intent
LOT	Leak-Off Test
M	cementation of exponent
M	Thousand
M	meter

MAASP	Maximum Allowable Annular Surface Pressure
Mbbl/d	Thousands of barrels of liquid per day
Mbo/d	Thousands of barrels per day
Mboe/d	Thousands of barrels of oil equivalent per day
Mbw/d	Thousands of barrels of water per day
Md	milli darcy
MD	Measured (Along Hole) Depth
MDBRT	Measured Depth below Rotary Table
MDQ	Maximum daily contract quantity
MDT	Modular drawdown tool
MM	Million
MMBtu	Millions of British Thermal units
M MDBRT	Metres measured depth below rotary table
MMscf	Millions of standard cubic feet
MMscf/d	Millions of standard cubic feet per day
MOD	Money of the day
MOU	Memorandum of understanding
MST	Multi-stage Triaxial
Mstb/d	Thousands of stock tank barrels
MMstb	Millions of US stock tank barrels
MMstb	Millions standard baerrels
MMt/yr	Million metric tonnes per annum
M TVDss	Metres true vertical depth below sea level
MW	Megawatt (106 watt)
N_2	Nitrogen
N	Saturation exponent
Ng	Corey coefficient for gas
NGL	Natural gas liquids
Nog	Corey coefficient for oil (in oil/gas system)
Now	Corey coefficient for oil (in oil/water system)
NPV	Net present value

NPVi	Net present value at discounted rate i
Nw	Corey coefficient for water
OBC	Ocean bottom cable
OD	Outer Diameter
OWC	Oil Water contact
P90, P50, P10	Values on the cumulative probability distribution with a 90% 50% or 10% chance respectively of being exceeded
PBU	Pressure Build-Up
PBYS	Pipe Body Yield Strength
PI	Productivity Index
PJ	Petajoule (10 15 joule)
PLT	Production Logging Tool
Por	Porosity
POS	Probability of success
Ppm	parts per million
PSC	Production sharing contract
PSDM	Pre stack depth migration
PV	Present value
PVT	Pressure volume temperature
P&T	Pressure and Temperature
Q	Quarter year
Reserves	Technically and economically recoverable hydrocarbon volumes (remaining reserves unless specifically qualified "original")
RF	Recovery factor
RFT	Repeat formation tester
Risked	The sum of the product of the values of all credible future outcomes multiplied by their associated probability. For an exploration prospect this includes the possibility and consequences if failure of an exploration well
ROV	Remotely operated value
Rs	Solution gas-oil ratio
RSM	Root mean square
RTE	Rotary Table Elevation

RVP	Reid vapour pressure
Rw	Water resistency
SCAL	Special core analysis
Scw	Connate water saturation
SF	Sanding Factor
SG	Specific Gravity
Sg	Gas saturation
Sgc	Critical gas saturation
SGIIP	Solution gas initially in place
Sgr	Residual gas saturation
Sh	Hydrocarbon saturation
SMS	Safety management system
Sor	Residual oil saturation
Sorg	Residual oil saturation in oil/gas
Sorw	Residual oil saturation in oil/water system
Sr	Condensate gas ratio
Srg	Residual gas saturation
Ss	sub-sea / subsea
SSIV	Subsurface isolation value
Stb/d	US stock tank barrel per day
STOIIP	Stock tank oil initially in place
SWC	Side wall cores
Tcf	Tera cubic feet (one million million cubic feet)
TCQ	Total cotact quantity
TD	Total Depth
THP	Tubing Head Pressure
THT	Tubing head Temperature
TJ/d si	Terajoule per day
TJ si	Terajoule (10_2 joule)
TOC	Top of Cement
TOL	Top of Liner

TRSSSV	Tubing retrievable subsurface safety valve
TSA	Tubing Stress Analysis
TVD	True Vertical Depth
TVDSS	True Vertical Depth Sub-Sea
TWC	Thick Walled Cylinder
TWT	Two way time
UCS	Unconfirmed Compressive Strength
UR	Ultimate recovery
US$	United States dollars
UTM ED50 0 deg	Standard coordinate system in use for well locations by Shell UK
Vz	Seismic velocity (at depth z)
Vo	Seismic velocity
VSP	Vertical Seismic profile
WAT	Wax Appearance Temperature
WCSITHP	Worst Case Shut-In Tubing Head Pressure
WHP	Well head pressure
Xho	Mass fraction of the “heavy” component (eg surface oil) in the reservoir oil
Xlo	Mass fraction of the “light” component (eg surface gas) in the reservoir oil
Z	Depth
£MM	Millions of UK pounds

PRMS (2007) System Specific Glossary

Term	Reference	Definition
1C	2007 - 2.2.2	Denotes low estimate scenario of Contingent Resources.
2C	2007 - 2.2.2	Denotes best estimate scenario of Contingent Resources.
3C	2007 - 2.2.2	Denotes high estimate scenario of Contingent Resources.
1P	2007 - 2.2.2	Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.
2P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.
3P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.
Accumulation	2001 - 2.3	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	2007 - 3.5.1 2001 - 6	The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Approved for Development	2007 - Table I	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway.
Analogous Reservoir	2007 - 3.4.1	Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.
Assessment	2007 - 1.2	See Evaluation.
Associated Gas		Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Barrels of Oil Equivalent (BOE)	2001 - 3.7	See Crude Oil Equivalent.
Basin-Centered Gas	2007 - 2.4	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs and lack of a down-dip water leg.

Behind-Pipe Reserves	2007 - 2.1.3.1	Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Best Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Bitumen	2007 - 2.4	See Natural Bitumen.
Buy Back Agreement		An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit.
Carried Interest	2001 - 9.6.7	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest.
Chance	2007 - 1.1	Chance is 1- Risk. (See Risk)
Coalbed Methane (CBM)	2007 - 2.4	Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC)
Commercial	2007 - 2.1.2 and Table 1	When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.
Committed Project	2007 - 2.1.2 and Table 1	Projects are committed only when it can be demonstrated that there is a firm intention to develop them and bring them to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production.

Completion		Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities.
Completion Interval		The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	2001 - 9.6.1	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned.
Condensate	2001 - 3.2	Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) on two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate.
Conditions	2007 - 3.1	The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies).
Constant Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs or revenues over the evaluation period.
Contingency	2007 - 3.1 and Table 1	See Conditions.
Contingent Project	2007 - 2.1.2	Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled.
Contingent Resources	2007 - 1.1 and Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.

Conventional Crude Oil	2007 - 2.4	Crude oil flowing naturally or capable of being pumped without further processing or dilution (see Crude Oil).
Conventional Gas	2007 - 2.4	Conventional Gas is a natural gas occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production
Conventional Resources	2007 - 2.4	Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Conveyance	2001 - 9.6.9	Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.
Cost Recovery	2001 - 9.6.2, 9.7.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks.
Crude Oil	2001 - 3.1	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Crude Oil Equivalent	2001 - 3.7	Converting gas volumes to the oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. There are a number of methodologies in common use. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 5,600 standard cubic feet (scf) of gas to 1 BOE = 6,000 scf. (Many operators use 1 BOE = 5,620 scf derived from the metric unit equivalent 1 m^3 crude oil = 1,000 m^3 natural gas). (Also termed Barrels of Oil Equivalent.)
Cumulative Production	2007 - 1.1	The sum of production of oil and gas to date (see also Production).
Current Economic Conditions	2007 - 3.1.1	Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a 1-year historical average of costs and prices should be used as the default basis of “constant case” resources estimates and associated project cash flows.
Cushion Gas Volume		With respect to underground natural gas storage, Cushion Gas Volume (CGV) is the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and non-recoverable in-situ gas volumes and injected gas volumes.

Deterministic Estimate	2007 - 3.5	The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.
Developed Reserves	2007 - 2.1.3.2 and Table 2	Developed Reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered “developed” only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells which will require additional completion work or future re- completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Development Not Viable	2007 - 2.1.3.1 and Table 1	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Pending	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Plan	2007 - 1.2	The design specifications, timing and cost estimates of the development project including, but not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation and marketing. (See also Project.)
Development Unclarified or On Hold	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Discovered	2007 - 2.1.1	A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in- place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulations.)

Discovered Petroleum Initially-in-Place	2007 - 1.1	Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-in-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially recoverable portion being classified as Reserves and the estimated sub-commercial recoverable portion being classified as Contingent Resources.
Dry Gas	2001 - 3.2	Dry Gas is a natural gas remaining after hydrocarbon liquids have been removed prior to the reference point. The dry gas and removed hydrocarbon liquids are accounted for separately in resource assessments. It should be recognized that this is a resource assessment definition and not a phase behavior definition. (Also called Lean Gas.)
Dry Hole	2001 - 2.5	A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Economic	2007 - 2001 - 4.3	In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses or attributable to, that operation.
Economic Interest	2001 - 9.4.1	An Economic Interest is possessed in every case in which an investor has acquired any Interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital.
Economic	2007 - 2001 - 4.3	Economic limit is defined as the production rate beyond which the net cash flows (after royalties or share of production owing to others) from a which may be an individual well, lease, or entire field, are negative.
Entitlement	2007 - 3.3	That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor.
Entity	2007 - 3.0	Entity is a legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Estimated Ultimate Recovery (EUR)	2007 - 1.1	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities produced therefrom.
Evaluation	2007- 3.0	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.)

Evaluator	2007 - 1.2, 2.1.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic in the project or independent consultants contracted for reviews and cases, the entity accepting the evaluation takes responsibility for the including Reserves and Resources and attributed value estimates.
Exploration		Prospecting for undiscovered petroleum.
Field	2001 - 2.3	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.
Flare Gas	2007 - 2001 - 3.1	Total volume of gas vented or burned as part of production and operations.
Flow Test	2007 - 2.1.1	An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).
Fluid Contacts	2007 - 2.2.2	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Forward Sales	2001 - 9.6.6	There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case.
Fuel Gas	2007 - 3.2.2	See Lease Fuel.
Gas Balance	2007 - 2001 -	In gas production operations involving multiple working interest owners, imbalance in gas deliveries can occur. These imbalances must be over time and eventually balanced in accordance with accepted procedures.

Gas Cap Gas	2001 - 6.2.2	Gas Cap Gas is a free natural gas which overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas.
Gas Hydrates	2007 - 2.4	Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage- like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed.
Gas Inventory		With respect to underground natural gas storage, “gas inventory” is the sum of Working Gas Volume and Cushion Gas Volume.
Gas/Oil Ratio	2007 - 3.4.4	Gas to oil ratio in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil , symbol *Rs*; produced gas/oil ratio, symbol *Rp*; or another suitably defined ratio of gas production to oil production.
Gas Plant Products		Gas Plant Products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas Plant Products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulfur, carbon dioxide, nitrogen, and helium.
Gas-to-Liquids (GTL) Projects		Gas-to-Liquids projects use specialized processing (e.g., Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products. Typically, these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic.
Geostatistical Methods	2001 - 7.1	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance.
High Estimate	2007 - 2001 - 2.5	With respect to resource categorization, this is considered to be an estimate of the quantity that will actually be recovered from an project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or high estimate.
Hydrocarbons	2007 - 1.1	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.

Improved Recovery (IR)	2007 - 2.3.4	Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)
Injection	2001 - 3.5 2007 - 3.2.5	The forcing, pumping, or free flow under vacuum, of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	2007 - 2.1.3.1 and Table 1	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Kerogen		The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	2007 - 2.1.1 2001 - 2.2	An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as “known,” and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.
Lead	2007 - 2.1.3.1 and Table 1	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Lease Condensate		Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.
Lease Fuel	2007 - 3.2.2	Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense.
Lease Plant		A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed “Local Gas Plant”).
Liquefied Natural Gas (LNG) Project		Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/614 the volume of natural gas at standard temperature and pressure.

Low/Best/ Estimates	2007 - 2.2.2	The range of uncertainty reflects a reasonable range of estimated recoverable volumes at varying degrees of uncertainty (using the scenario approach) for an individual accumulation or a project.
Low Estimate	2007 - 2001 - 2.5	With respect to resource categorization, this is considered to be a estimate of the quantity that will actually be recovered from the a project. If probabilistic methods are used, there should be at least a probability (P90) that the quantities actually recovered will equal or low estimate.
Lowest Known Hydrocarbons	2007 - 2.2.2.	The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data.
Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which a development project(s) evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack market and/or infrastructure).
Measurement	2007 - 3.0	The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Interest	2001 - 9.3	Mineral Interests in properties including (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	2001 - 5 2007 - 3.5	A type of stochastic mathematical simulation that randomly and samples input distributions (e.g., reservoir properties) to generate a distribution (e.g., recoverable petroleum volumes).
Natural Bitumen	2007 - 2.4	Natural Bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen.)
Natural Gas	2007 - 2001 - 6.6, 9.4.4	Natural Gas is the portion of petroleum that exists either in the gaseous is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural some amount of non-hydrocarbons.

Natural Gas Inventory		With respect to underground natural gas storage operations “inventory” is the total of working and cushion gas volumes.
Natural Gas Liquids	2007 - 2001 - 3.2, 9.4.4	Natural Gas Liquids (NGL) are a mixture of light hydrocarbons that exist gaseous phase and are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is recovered in gas plants rather than lease separators or other lease (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as the pentanes-plus that are the main constituents of condensates.
Natural Gas Liquids to Gas Ratio		Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.
Net-Back	2007 - 3.2.1	Linkage of input resource to the market price of the refined products.
Net Profits Interest	2001 - 9.4.4	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net Working Interest	2001 - 9.6.1	A company’s working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called Net Revenue Interest.)
Non-Hydrocarbon Gas	2007 - 2001 - 3.3	Natural occurring associated gases such as nitrogen, carbon dioxide, sulfide, and helium. If non-hydrocarbon gases are present, the reported should reflect the condition of the gas at the point of sale. accounts will reflect the value of the gas product at the point of sale.
Non-Associated Gas		Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.
Normal Production Practices		Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes.
Oil Sands		Sand deposits highly saturated with natural bitumen. Also called “Tar Sands.” Note that in deposits such as the western Canada “oil sands,” significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.
Oil Shales	2007 - 2.4	Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).
Offset Well Location		Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location there must be conclusive, unambiguous technical data which supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon.

On Production	2007 - 2.1.3.1 and Table 1	The development project is currently producing and selling petroleum to market. A project status/maturity sub-class that reflects the actions required to move a project toward commercial production.
Operator		The company or individual responsible for managing an exploration, development, or production operation.
Overlift/Underlift	2007 - 3.2.7 2001 - 3.9	Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year.
Penetration	2007 - 1.2	The intersection of a wellbore with a reservoir.
Petroleum	2007 - 1.0	Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non- hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.
Petroleum Initially-in-Place	2007 - 1.1	Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas- in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.)
Pilot Project	2007 - 2.3.4, 2.4	A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.
Play	2007 - 2.1.3.1 and Table 1	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Pool		An individual and separate accumulation of petroleum in a reservoir.
Possible Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery		Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.

Probabilistic Estimate	2007 - 3.5	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	2007 - 1.1	Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.
Production-Sharing Contract	2007 - 3.3.2 2001 - 9.6.2	In a production-sharing contract between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced.
Profit Split	2001 - 9.6.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks.
Project	2007 - 1.2 2001 - 2.3	Represents the link between the petroleum accumulation and the decision- making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	2007 - 1.2 2001 - 9.4	A volume of the Earth’s crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prorationing		The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc.

Prospective Resources	2007 - 1.1 and Table 1	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Economic	2007 - 3.1.1	In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic."
Proved Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven."
Purchase Contracts	2001 - 9.6.8	A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term.
Pure-Service Contract	2001 - 9.7.5	A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors.
Range of Uncertainty	2007 - 2.2 2001 - 2.5	The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource Uncertainty Categories.)
Raw Natural Gas	2007 - 3.2.1	Raw Natural Gas is natural gas as it is produced from the reservoir. It includes water vapor and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulfur compounds such as hydrogen sulfide and other non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw Natural Gas is often not suitable for direct utilization by most types of consumers.
Reasonable Certainty	2007 - 2.2.2	If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered.
Reasonable Expectation	2007 - 2.1.2	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will
Reasonable Forecast	2007 - 3.1.2	Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models.

Recovery Efficiency	2007 - 2.2	A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage.
Reference Point	2007 - 3.2.1	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.
Reserves	2007 - 1.1	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	2001 - 2.3	A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.
Resources	2007 - 1.1	The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional” (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.)
Resources Categories	2007 - 2.2 and Table 3	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes)
Resources Classes	2007 - 1.1, 2.1 and Table 1	Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project’s estimated chance of reaching producing status.
Revenue-Sharing Contract	2001 - 9.6.3	Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary Interest		The right of future possession of an interest in a property when a specified condition has been met.
Risk	2001 - 2.5	The probability of loss or failure. As “risk” is generally associated with the negative outcome, the term “chance” is preferred for general usage to describe the probability of a discrete event occurring.

Risk and Reward	2001 - 9.4	Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risked-Service Contract	2007 - 3.3.2 2001 - 9.7.4	These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	2007 - 3.3.1 2001 - 3.8	Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.
Sales	2007 - 3.2	The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements.
Shut-in Reserves	2007 - 2.1.3.2 and Table 2	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing; (2) wells which were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons.
Solution Gas		Solution Gas is a natural gas which is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas.
Sour Natural Gas	2001 - 3.4	Sour Natural Gas is a natural gas that contains sulfur, sulfur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use.
Stochastic	2001 - 5	Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.
Sub-Commercial	2007 - 2.1.2	A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.
Sub-Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions.

Synthetic Crude Oil (SCO)	2001 - A12, A13	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other non- hydrocarbon compounds and has many similarities to crude oil.
Taxes	2001 - 9.4.2	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Uncertainty	2007 - 2.2	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Total Petroleum Initially-in-Place	2007 - 1.1	Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, as well as those quantities already produced. This was defined previously by the WPC as “Petroleum-in- place” and has been termed “Resource Base” by others. Also termed “Original- in-Place” or “Hydrocarbon Endowment.”
Uncertainty	2007 - 2.2 2001 - 2.5	The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	2007 - 2.4,	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called “continuous-type deposits”). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed “Non-Conventional” Resources and “Continuous Deposits.”)
Undeveloped Reserves	2001 - 2.1.3.1 and Table 2	Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Unitization		Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from the shared reservoir(s).
Unproved Reserves	2001 - 5.1.1	Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.

Unrecoverable Resources	2007 - 1.1	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.
Upgrader	2007 - 2.4	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Well Abandonment		The permanent plugging of a dry hole, an injection well, an exploration well, or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications such as reservoir monitoring, enhanced recovery, etc.
Wet Gas	2001 - 3.2	Wet (Rich) Gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource there is no separate accounting for contained liquids. I t should be that this is a resource assessment definition and not a phase behavior definition.
Working Gas Volume		With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume is gas in storage above the designed level of cushion gas which can be withdrawn/injected with the installed subsurface and surface facilities (well, flow lines etc) subject to legal and technical limitation s (pressures, velocities etc). Depending on local site conditions (injection/withdrawal rates, utilization hours etc) the working gas volume may be cycled more than once a year.
Working interest	2001-9	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

APPENDIX 4: PRODUCTION POTENTIAL OF THE ZECHSTEIN CARBONATE RAMP PLAY

The following is a summary by CNR on a potential Zechstein carbonate build-up play. This information has been supplied by CNR for completeness. The play is unexplored in the area and is currently being worked by CNR. The play has not been presented to be audited by Axis for prospective resources at this stage.

CNR CLUFF NATURAL RESOURCES PLC

P2252 - Southern North Sea

November 2015

Executive Summary

28th Round Promote Licence P2252 covers blocks 41/5, 41/10 and 42/5 which are located on the north western flank of the Southern North Sea gas basin where the Zechstein Carbonates have long been recognised as potentially significant reservoirs, although despite a significant number of well penetrations encountering movable gas these formations have historically been viewed primarily as drilling hazards to be overcome on the way to deeper targets within the Rotliegendes or Carboniferous.

While there has been some production from Zechstein Carbonates in the Southern North Sea gas basin it has not been systematically targeted as it has been in eastern Netherlands where 50 years of exploration and production history has resulted in a tried and tested workflow for evaluating the production potential of the Zechstein Carbonates. This workflow hinges on the accurate identification of the transition zone between slope and basin where post-burial deformation acts to enhance the reservoir characteristics of the carbonate

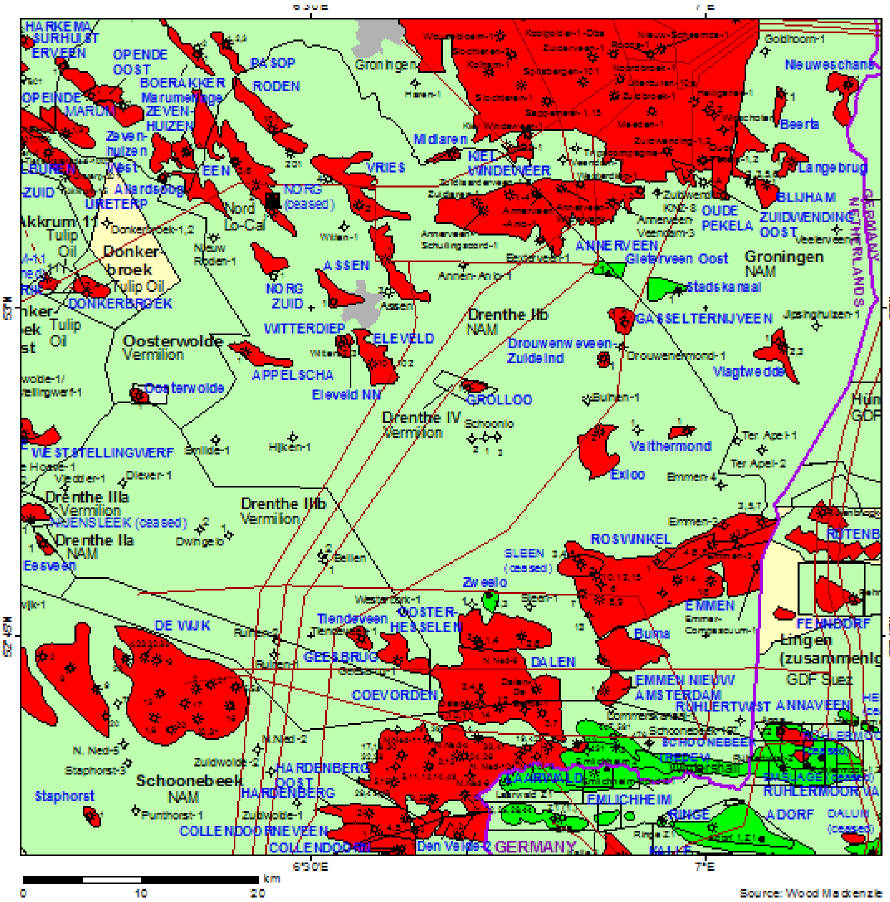
While the available historical dataset for P2252 does not currently allow a full evaluation of the Zechstein Carbonate play across the whole of the licence area, an area of 3D seismic which covers most of block 41/10 and the southern part of 41/5 gives an insight of the production potential via a conceptual 14 well development targeting the shelf-basin transition ramp in this area.

The Zechstein Ramp Play located within the existing 3D seismic volume on block 41/10 has a strike length of several kilometres and a width of between 2 and 4kms with a gas in place volume of approximately 440 BCF. Estimated Ultimate Recovery (EUR) for a conceptual 14 well development is of the order of 280 BCF which is worth approx. £1,059M @ 37.85p/therm.

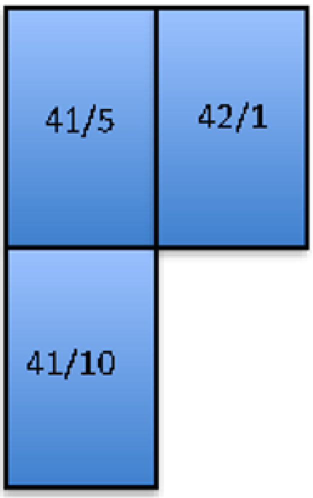
Analogous Play – Onshore Netherlands

While local examples of production from the Zechstein Carbonates in the SNS (Conoco well 41/24a-2z reported to have flows at 100MMscfd from the Plattendolomite) and onshore UK (Eskdale and Lockton gasfields) the best developed example of the Zechstein Carbonate play is located in eastern Netherlands. The key proponent of the Zechstein Carbonate Play in the Netherlands is NAM which has discovered of 20 gas fields with cumulative gas reserves of approximately 2.5TCF over the last 40 years. The Drenth Zechstein Complex alone has over 3.5 TCF of gas in place excluding the Tertiary aged Coevorden and Permian Groningen fields. This experience has led to the development of a predictive model based on 3D seismic data which uses a combination of isochore mapping to define the transition zone between shelf and basin along with fracture mapping which indicates enhanced reservoir characteristics.

Drilling and completion methodology is a key consideration in the development of the Carbonate Play in the Netherlands as the formation and fracture networks are extremely susceptible to damage during drilling operations. Horizontal production wells are drilled under-balanced, often with coil tubing, to prevent *formation damage while geo-steering is key to ensuring good contact with the reservoir. Average well recoveries are of the order of 20-30 BCF per well are reported.*



Drenth Zechstein Complex	OGIP (BCF)
Annerveen	1,247
Assen	10
Appelscha	55
Dalen	490
Een	1
Eleveld	40
Emmen	487
Emmen-Nieuw Amsterdam	40
Norg (Langelo)	109
Norg Zuid	37
Oosterhesselen	143
Roden	90
Roswinkel	437
Sleen	264
Vries	141
Gasselternijveen	29
Witterdeip	15
TOTAL	3,635



CLNR – P2252 Licence at same scale

Figure 4 - Summary of Zechstein Potential in eastern Holland

Exploration History – P2252

The area was first licensed by Conoco and Marathon in the early 1990's and the key 3D seismic dataset currently being used to define the transitional facies in the Zechstein Carbonates was acquired by Geco Prakla in 1993. This 3D survey was highlighted the Fairhaven and Lytham prospects which have conventional dip closures at both Namurian and Zechstein levels.

Well 41/10-1 drilled in 1995 targeted Namurian and Visean sandstone reservoirs within an intra-Carboniferous dip closure. This target horizons proved to be water wet however gas shows were reported in both the Plattendolomite and the Hauptdolomite.

The Fairhaven structure was tested by well 41/5-1 in 2004 which encountered gas shows in the Plattendolomite although the Hauptdolomite was subject to significant formation damage following the loss of >2,000 barrels of drilling mud to formation.

The Lytham structure was subsequently tested by wells 41/10a-2 & 2z in 2007 which encountered gas charged mixed slope and mud prone basinal deposits at the level of the Hauptdolomite with a 30m gas 30m gas column reported.

Drilling practices at the time routinely included mud programmes with more than 2000psi over balance as a precaution against gas kicks while drilling the Zechstein sequence which may have severely hampered the ability to properly assess the production potential of any fractured carbonate reservoir which may have exisited.

Most recently the area was held by Trapoil who reprocessed the original Marathon dataset but eventually relinquished the licence in January 2013 without drilling a well due to funding issues.

In addition to the wells drilled on the licence, Zechstein reservoirs, with interpreted gas pay, or gas shows as identified on mudlogs, were encountered in nearby wells 41/15-1, 42/16-1, 41/20-1, 41/20-2, 41/18-1 to the south west and onshore (Eskdale, Lockton), Well 42/9-1, to the south east, also encountered gas pay in the Hauptdolomite. The best recorded flow rates were from Conoco's 41/24a-1 and 41/25a-1 which tested gas from the Plattendolomite. Conoco 41/24a-2z was a horizontal well and is believed to have tested gas at circa 100 MMscfd. Production from the Zechstein in the Hewett field area (48/29, 48/30) has occurred from the 1980's

Regional Geology Summary – UK Southern North Sea

Licence P2252 is located at the northern end of the Southern North Sea approximately 100km to the East of Teesside. The blocks are located in the offshore extension of the Carboniferous Cleveland basin. The sedimentary sequence records 5 main depositional cycles, each commencing with a full or partial marine transgression typified by carbonate deposition.

The Carboniferous sequence is dominated by Namurian or Dinantian basinal marine shales overlain by Westphalian Coal Measures. During the Permian a regional basin, often referred to as the North German Basin, extending from the UK through to Poland was formed. This basin was fringed by Carbonate platforms which form the main Hauptdolomite and Plattendolomite target reservoirs on P2252. Restricted circulation during the Permian lead to the deposition of anhydrites and occasionally sulphates which form regional seals.

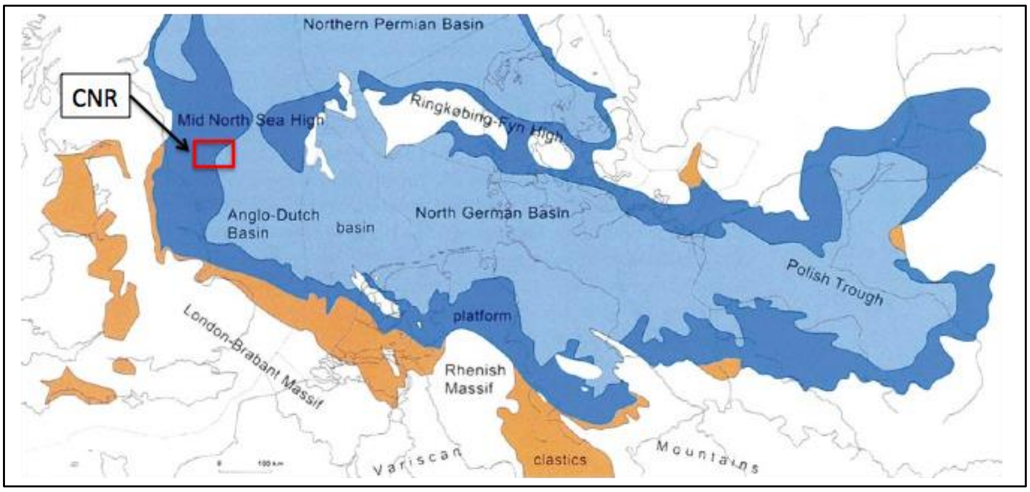


Figure 5 - Map showing approximate location of CNR licences in relation to shelf edge deposits (darker blue)

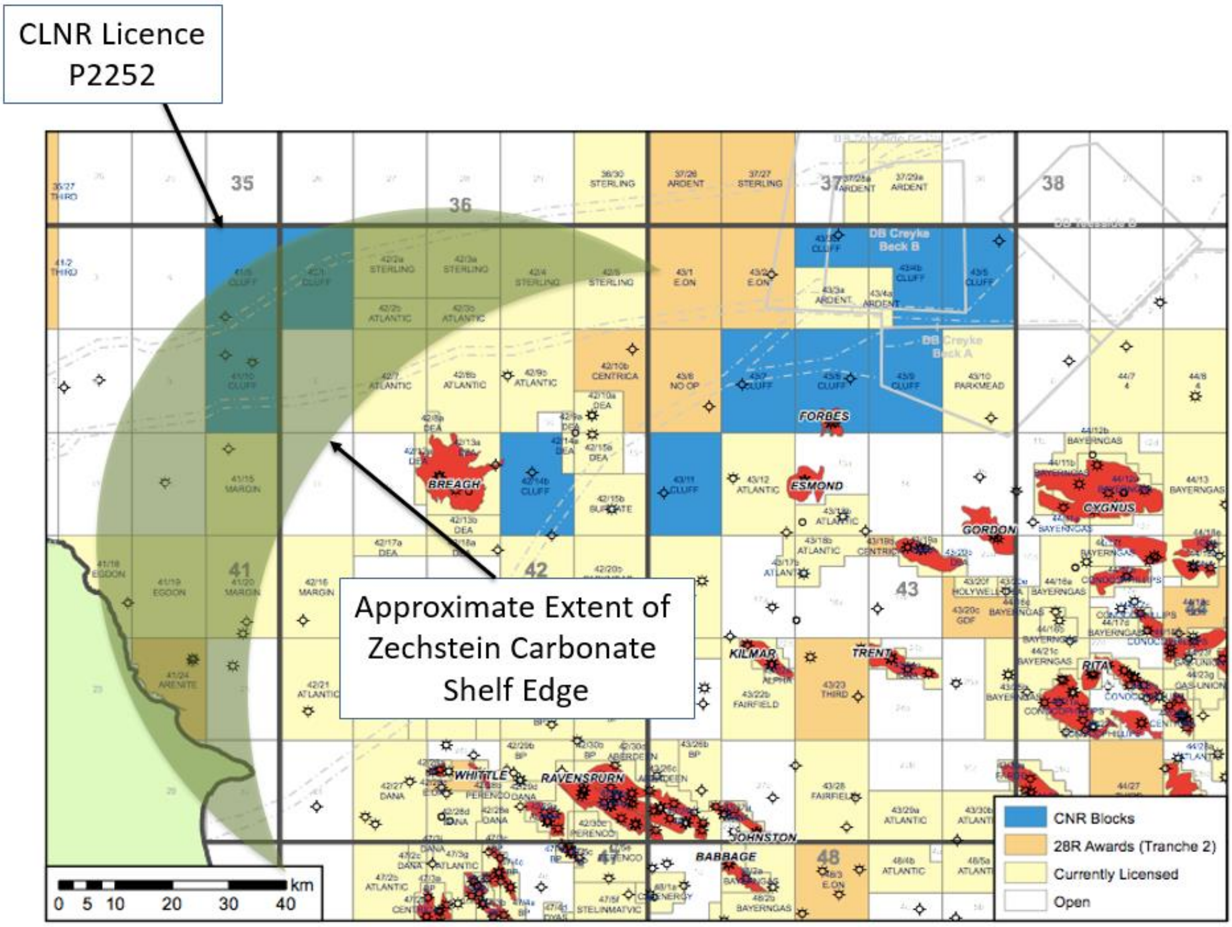


Figure 6 - Map showing Licence P2252 in North Sea context

Petroleum System –P2252

Source

While regionally the source of gas charge in the wider Permian basin is generally accepted to be coal of Westphalian age this is problematic in the area of P2252 and surrounds as the Westphalian is largely absent due to erosion. Long distance migration from gas generating coals elsewhere is potentially problematic and does not account for the 'wet' gases found in fields such as Breagh.

CNR's proprietary geochemistry suggests an older, Dinantian source, locally known as the Cementstone, probably generated the gas in the P2252 area. The Cementstone which was deposited in early syn-rift lows with limited circulation and likely hypersaline conditions is an oil prone source rock but is thought to have been cracked to gas and condensate with rapid, deep burial during late Carboniferous rifting.

The Cementstone as a local source addresses both the risks around long distance migration and the source of wet gas in this part of the North Sea.

Reservoir

The primary reservoirs consist of the 100m thick Plattendolomite and the 50m thick Hauptdolomite in the Zechstein which have been proven by wells on the licence. Gas within the Zechstein is pervasive, a regional stratigraphic phenomenon due to highly effective intra-formational salt seals such as the Stassfurt Halite, however primary reservoir characteristics may limit the commercial production potential outwith the areas of secondary fracturing.

Mapping the fracture corridor is therefore of key importance however this process has been made significantly quicker and cheaper by applying modern seismic interpretation software which autonomously track multiple surfaces. An example in Figure 4 clearly identifies the ramp between shelf and basin based on high resolution isochrones.

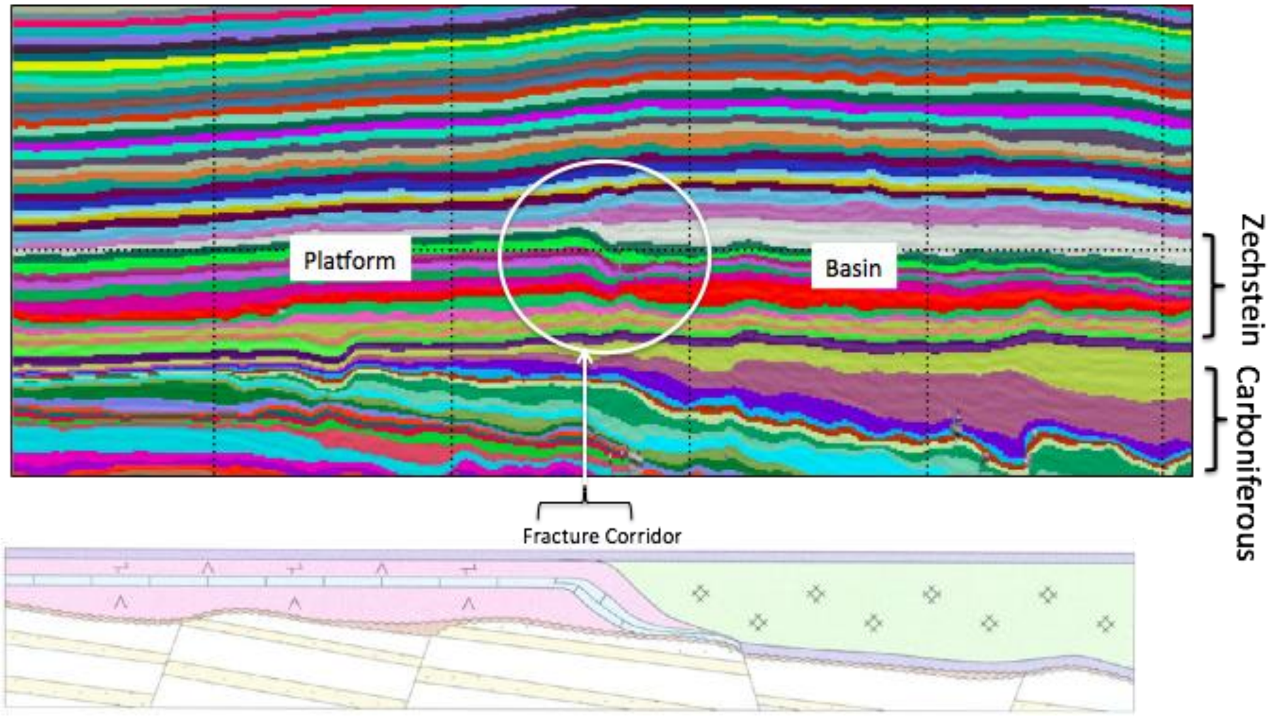


Figure 7 - P2252 cross section highlighting a 'ramp' or transition zone within the Zechstein from the Marathon 3D survey.

Most of the production in the basin is from the Z2 Hauptdolomite although there is some resources attributable to the Z3 Plattendolmite. Although outwith the main transition zone between shelf and basin the on-block well results indicate potentially good, to very good, localised reservoirs probably associated with secondary porosity, vugs and fracturing.
Based on results of well 41/41-2z the Hauptdolomite is assumed to have primary porosities in the range of 0-12% with gas saturations from 50-70%.

Potential Production Scenario – Scoping Volumetrics

To understand the production potential of the Zechstein Carbonate Ramp Play a hypothetical development case has been developed based on our current understanding of the reservoir and analogue developments in the Netherlands.
A conceptual reservoir model was constructed using the following assumptions:

PARAMETER	***VALUE***
Reservoir Thickness	*50 metres*
Drainage Area	*7,000m by 3,000m*
Porosity	*10%*
S_w	*40%*
B_{gi}	*0.005*

Based on the assumptions above this would indicate a potential OGIP in the region of 440 BCF within the fracture corridor. Note the prospect area is independent of structure and is effectively a stratigraphic trap defined by a combination of grainstone presence and natural fractures.

The fracture corridor would be targeted by a series of long (approx. 3,000m) horizontal wells drilled roughly perpendicular to the strike direction of the fracture corridor with inter-well spacing of approximately 500m. The development scenario includes 10 wells drill from a platform with an additional 4 wells connected back to the platform via a sub-sea tieback.

Potential Production Scenario – Estimated Ultimate Recovery

Assumptions using in the initial scoping of the development are as follows

PARAMETER	***ASSUMPTION***
Drilling	*2 wells per year for 5 years increasing to 3 wells per year*
Initial Production	*8 mmscfd for 3 years then declining at 20% per annum*
EUR per well	

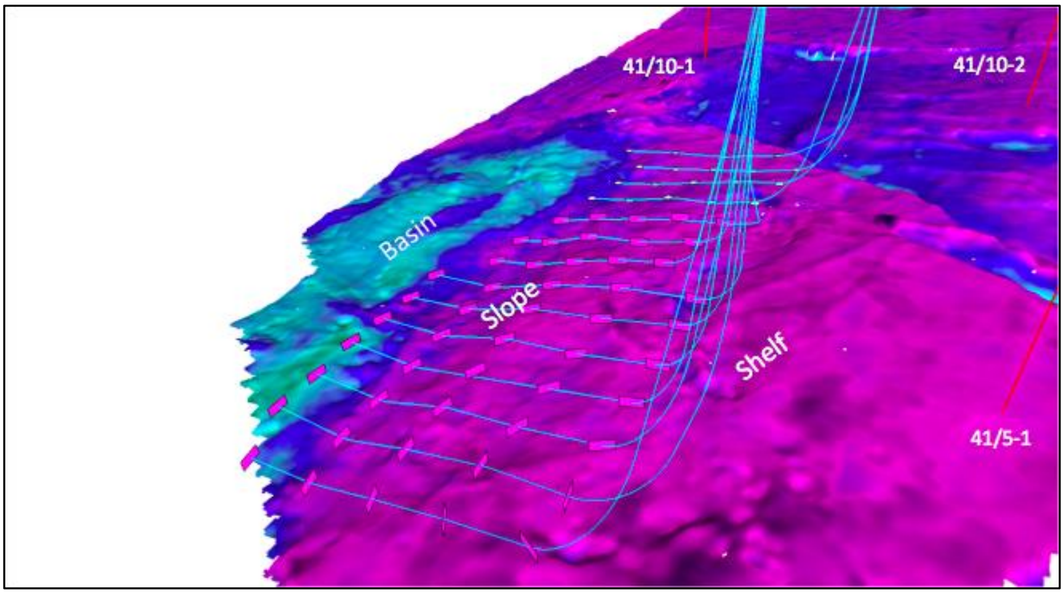


Figure 8 - Zechstein Ramp from Marathon 3D survey viewed from north-east with 10 platform wells + 4 well subsea tieback

Based on the above assumption the 14 well field development could potentially recover approximately 280 BCF of gas over the life of the field with peak production rates of nearly 90 mmscfd. The production profile is currently not optimised given the early stage of the project and overall project economic are yet to be evaluated.

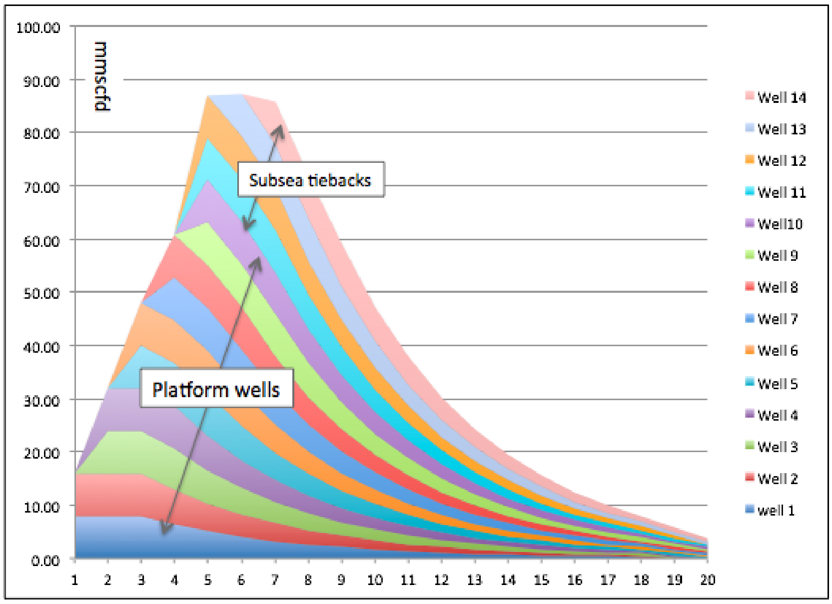


Figure 9 - Unoptimised production profile for a 14 well development

However the initial production rates and per well EUR's are considered to be conservative based on flow tests of 100mmscfd at the nearby Conoco Zechstein Carbonate test (41/24a-2z), the Wissey Field (block 53/4d) which produced from the Plattendolomite at a rate of 70mmscfd and target rates of 45mmscfd from 400m laterals at the Dalen field in Holland.

<u>Summary</u>

If the potential of the Zechstein Carbonate Play identified on Block 41/10 extends on to Block 41/5 and 42/1 there is the opportunity to create a significant new production hub in this part of the Southern North Sea which is located in relatively shallow water and close to existing infrastructure.
Work is ongoing to further de-risk this Zechstein Carbonate play.

CNR Assets in the Southern North Sea

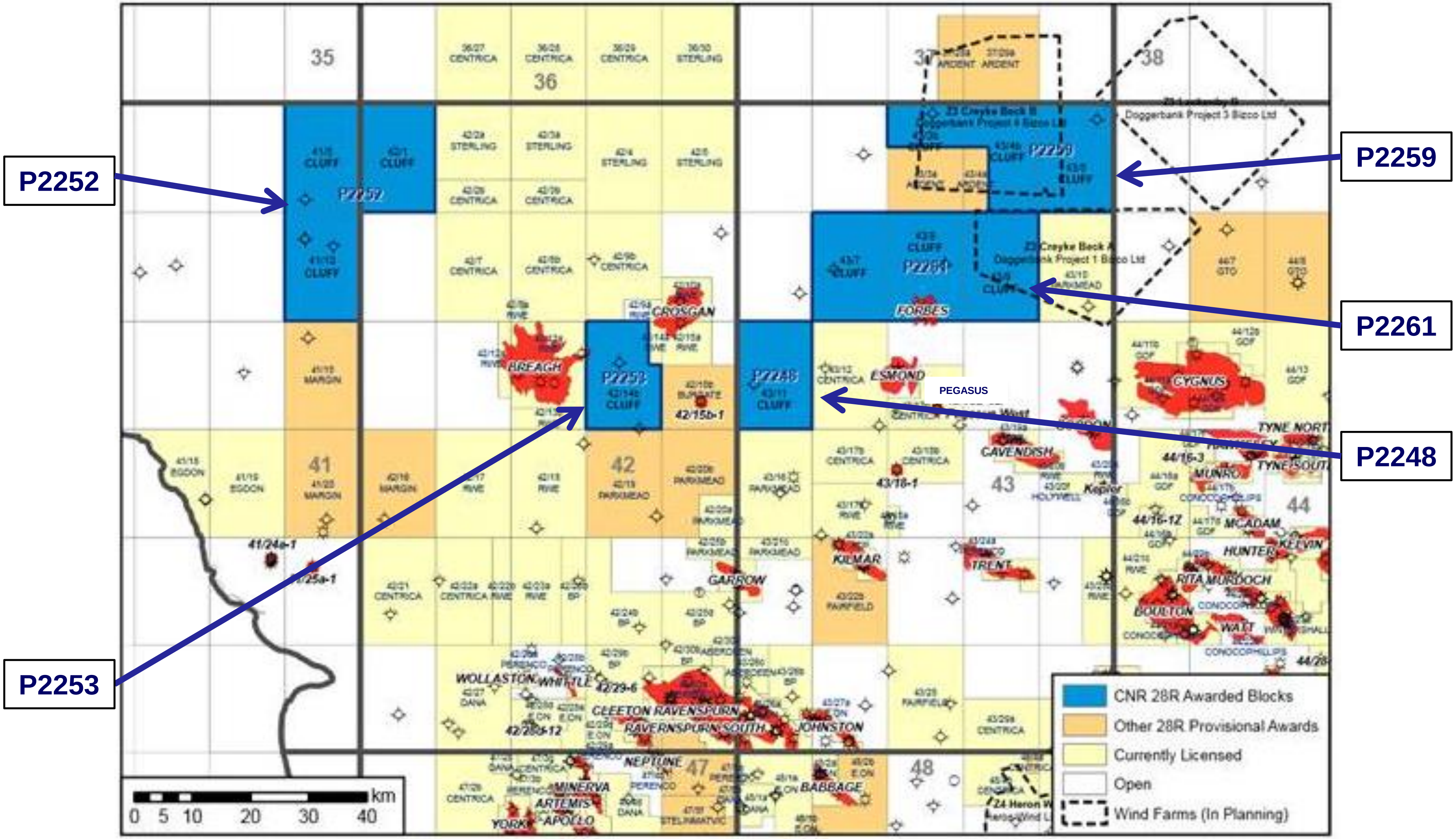


Figure 1.1

Stratigraphic Summary: Southern North Sea

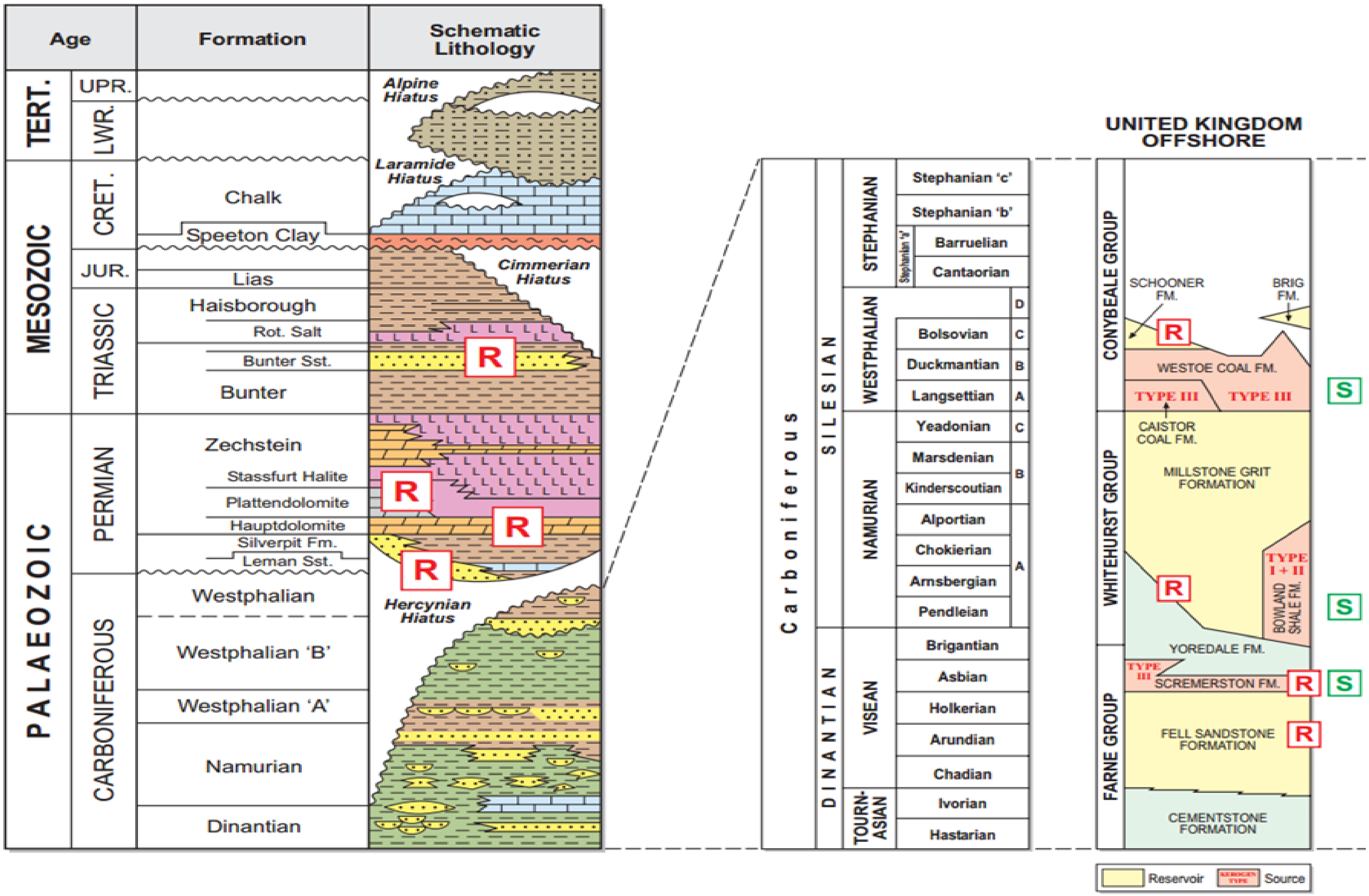


Figure 1.2

Prospective Plays in the Northern Sector of the Southern North Sea

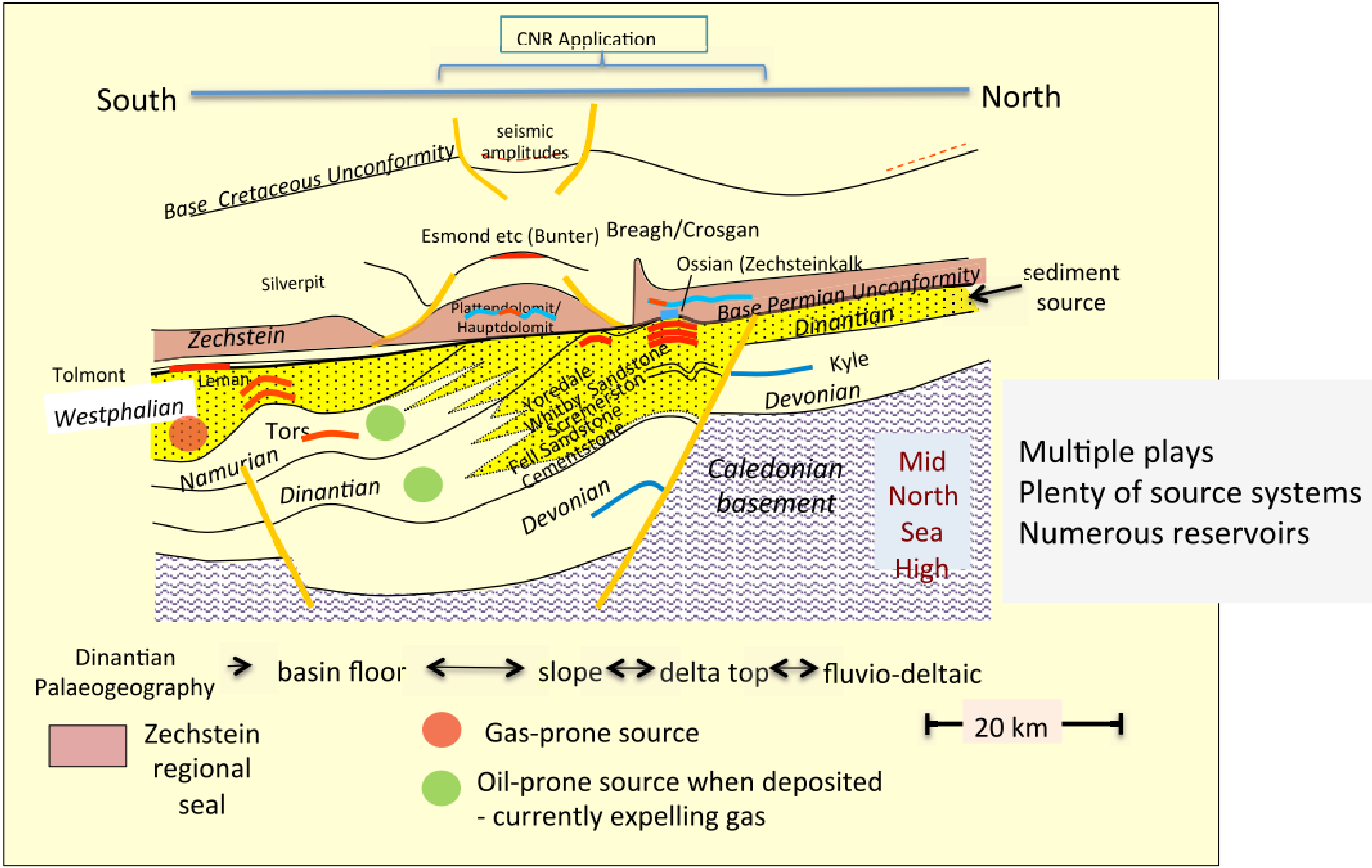


Figure 2.1

Source: CNR

Seismic Line through Wells 41/10a-2/2z and 41/10-1

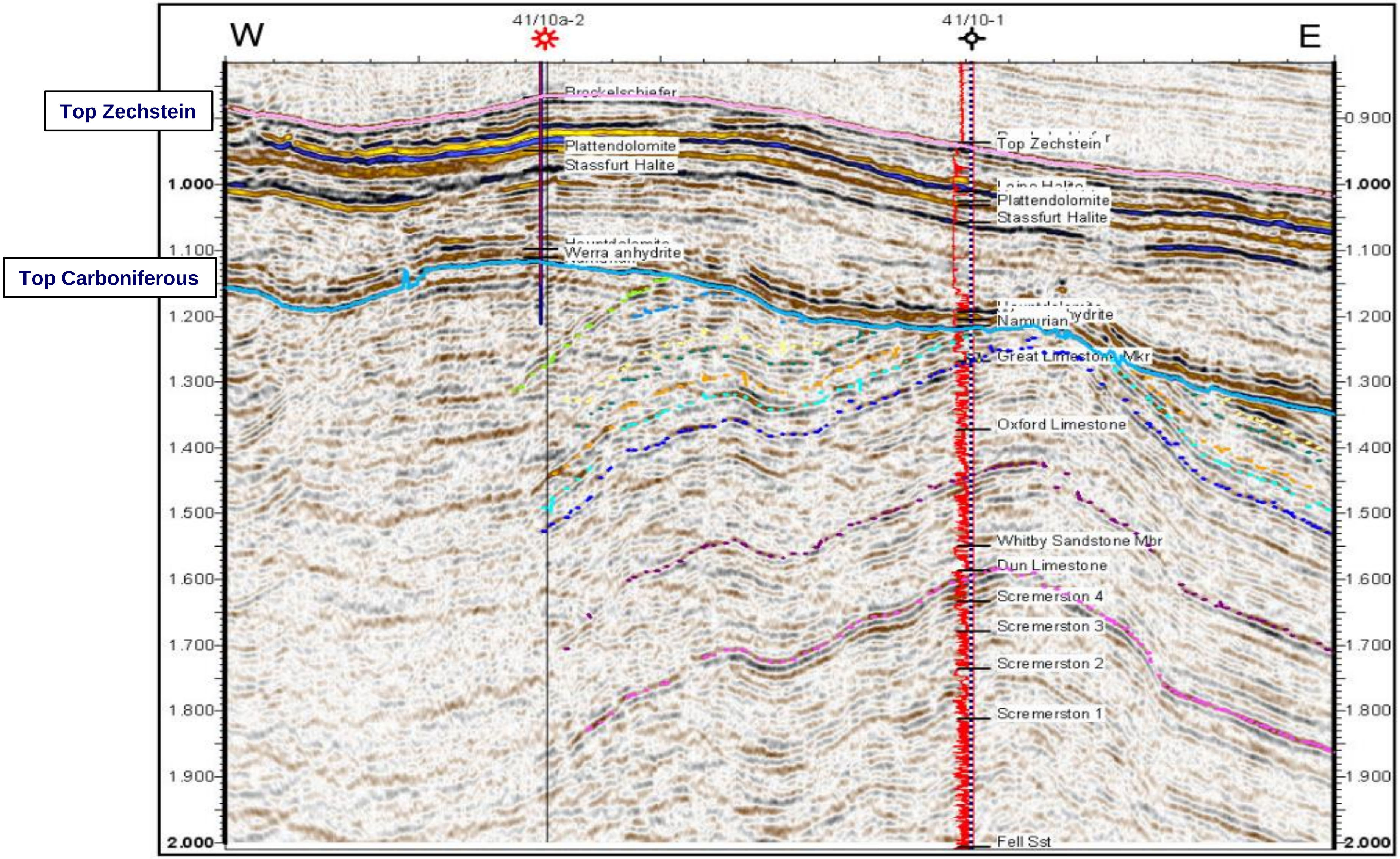


Figure 2.2

Source: Licence P1129 Relinquishment Report, Wintershall

Seismic Line through Wells 41/10a-2/2z and 41/5-1

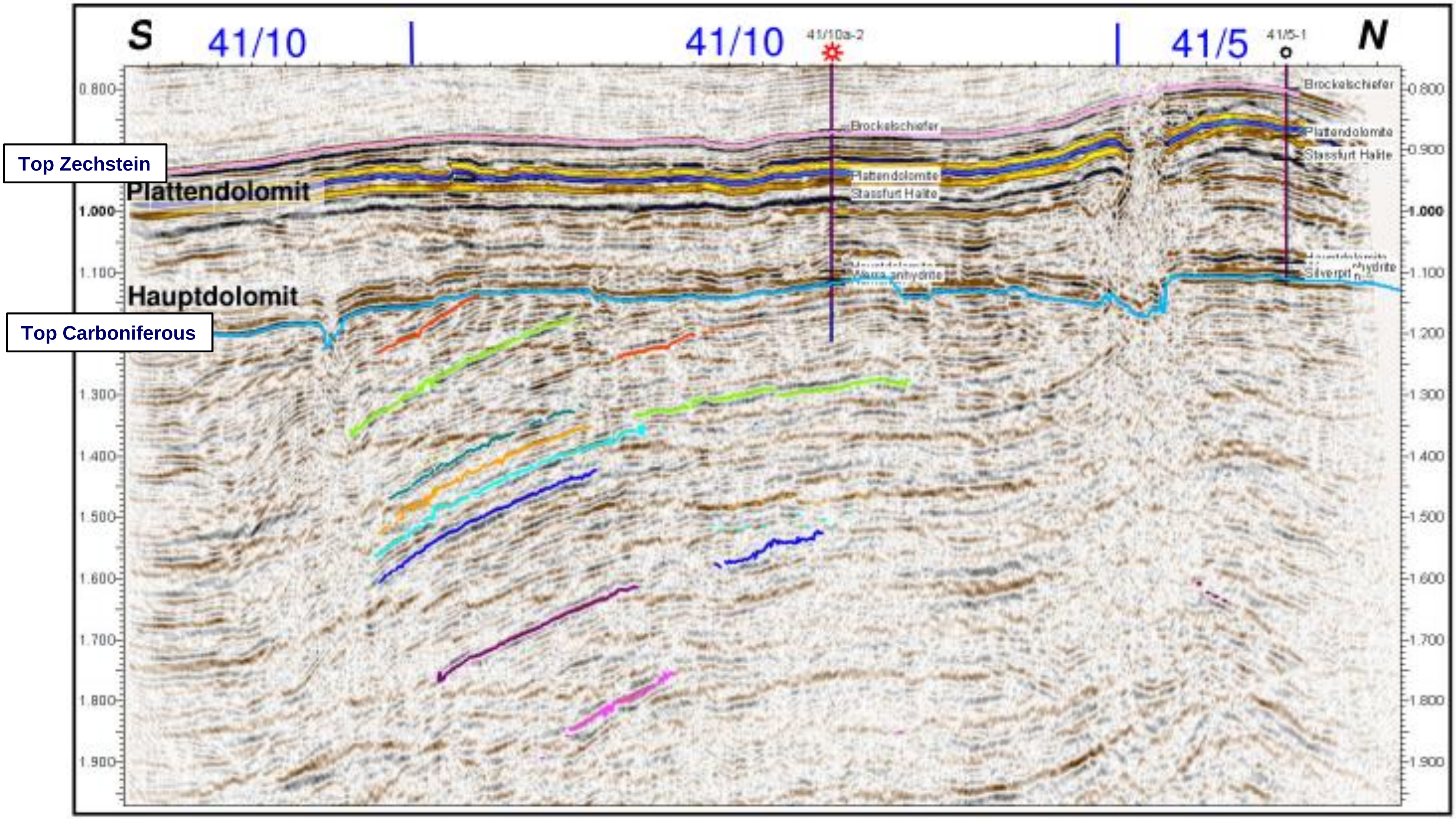


Figure 2.3

Source: Licence P1129 Relinquishment Report, Wintershall

Zechstein Hauptdolomite Possible Shelf Edge, 41/10 North-East Area

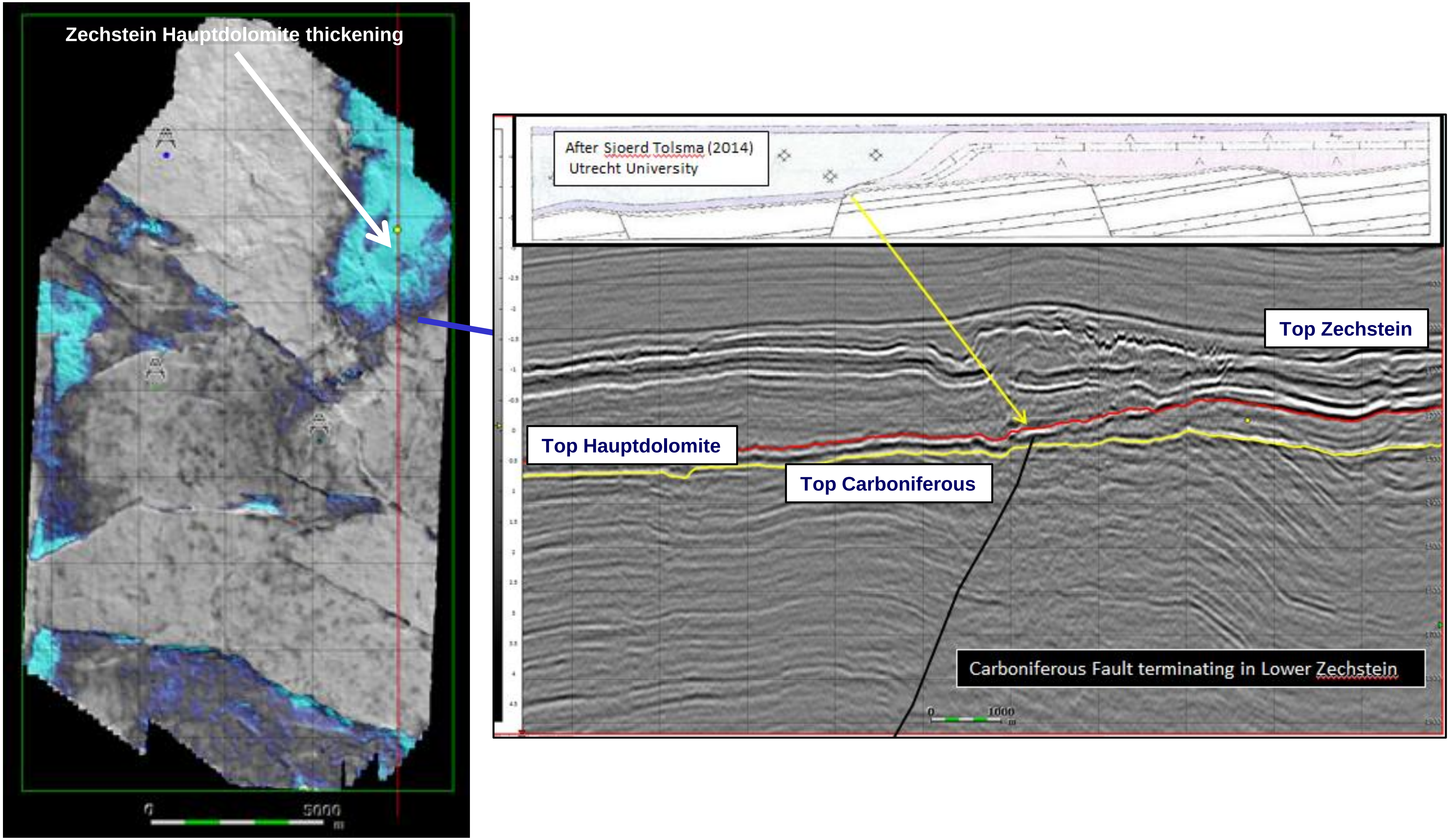
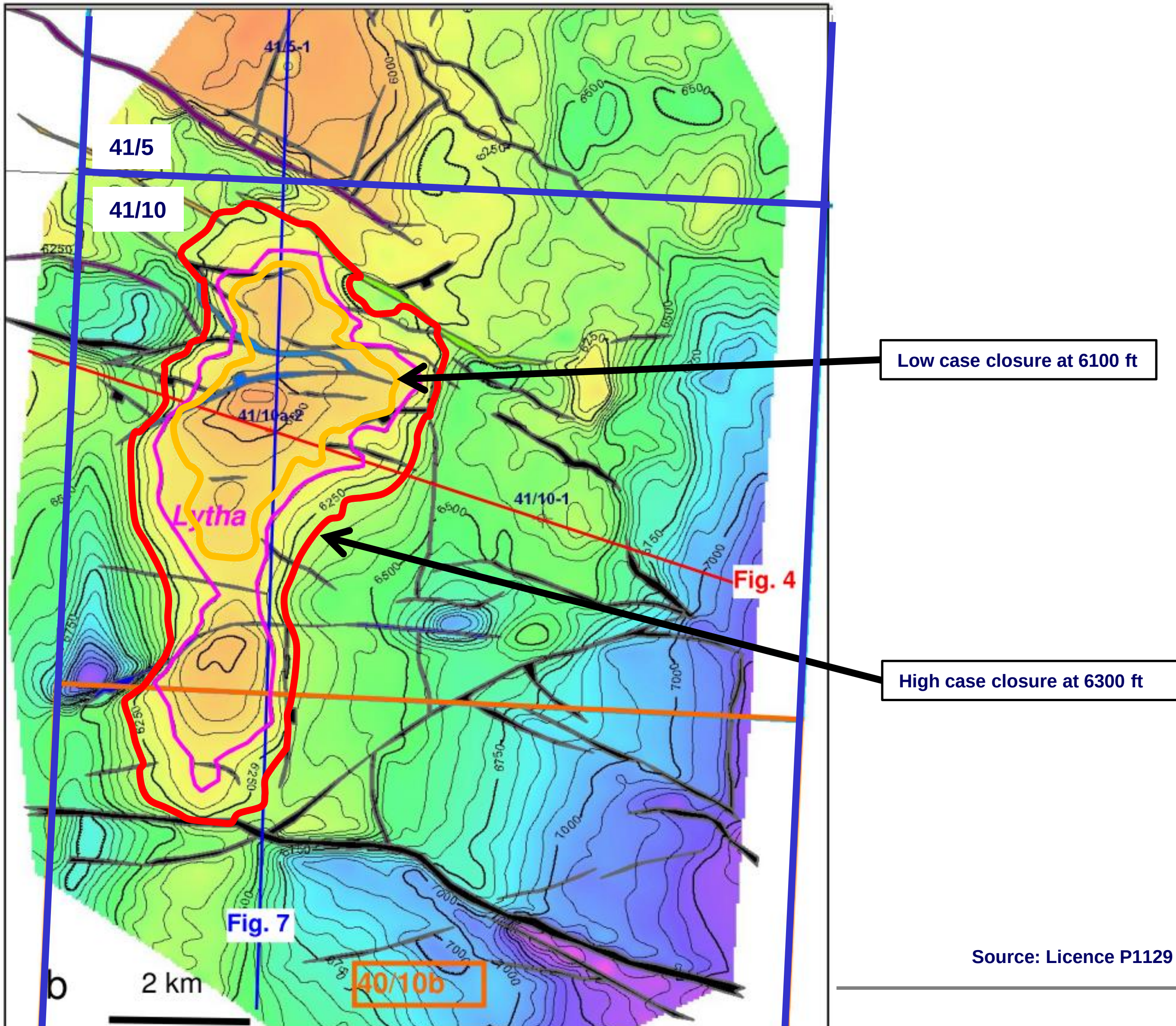


Figure 2.4

Source: Lyme Bay Consulting

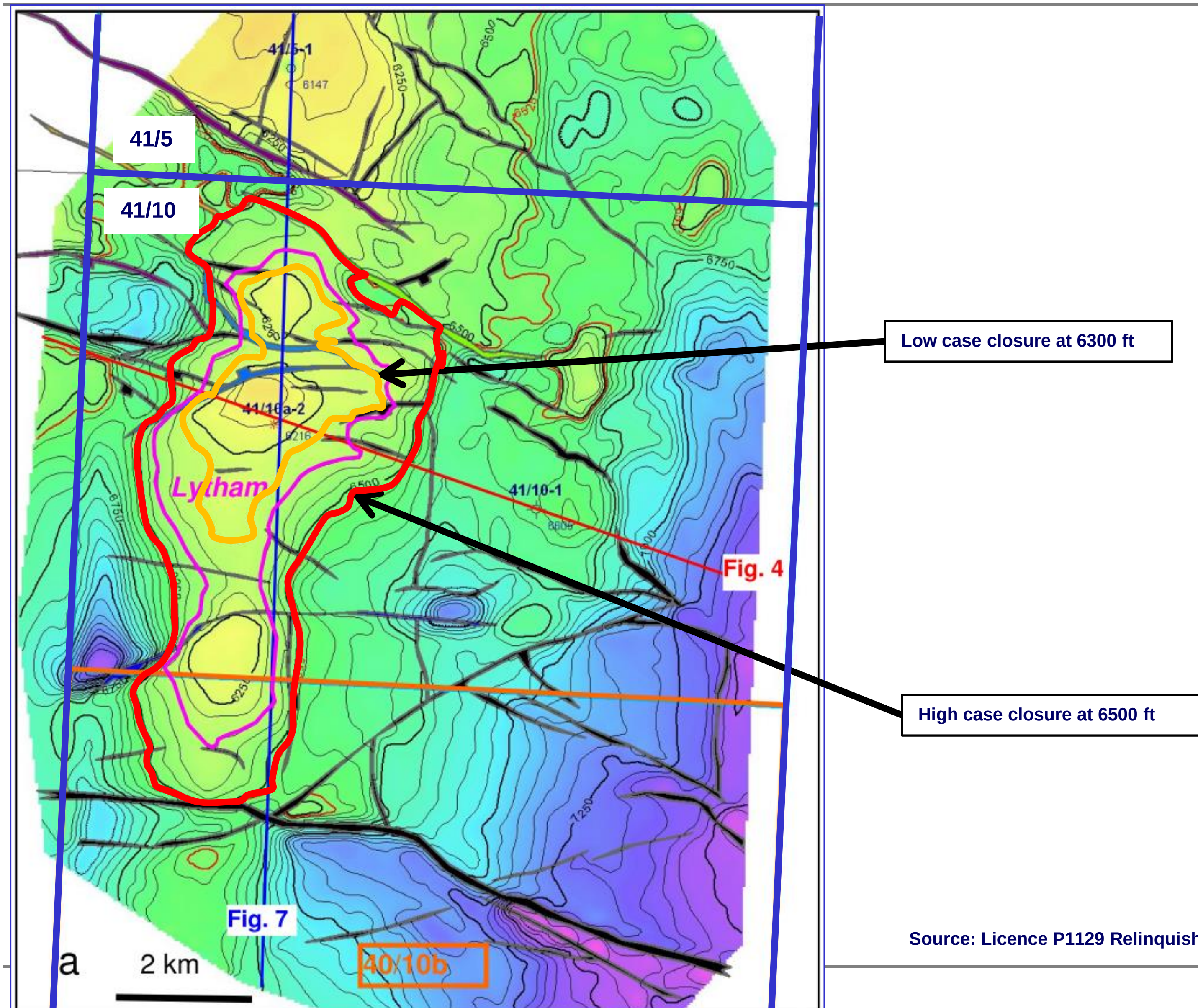
Lytham Prospect: Top Hauptdolomite Depth Map



Source: Licence P1129 Relinquishment Report, Wintershall

Figure 2.5

Lytham Prospect: Top Carboniferous Depth Map



Source: Licence P1129 Relinquishment Report, Wintershall

Figure 2.6

Fairhaven Prospect: Top Plattendolomite Depth & Time Map

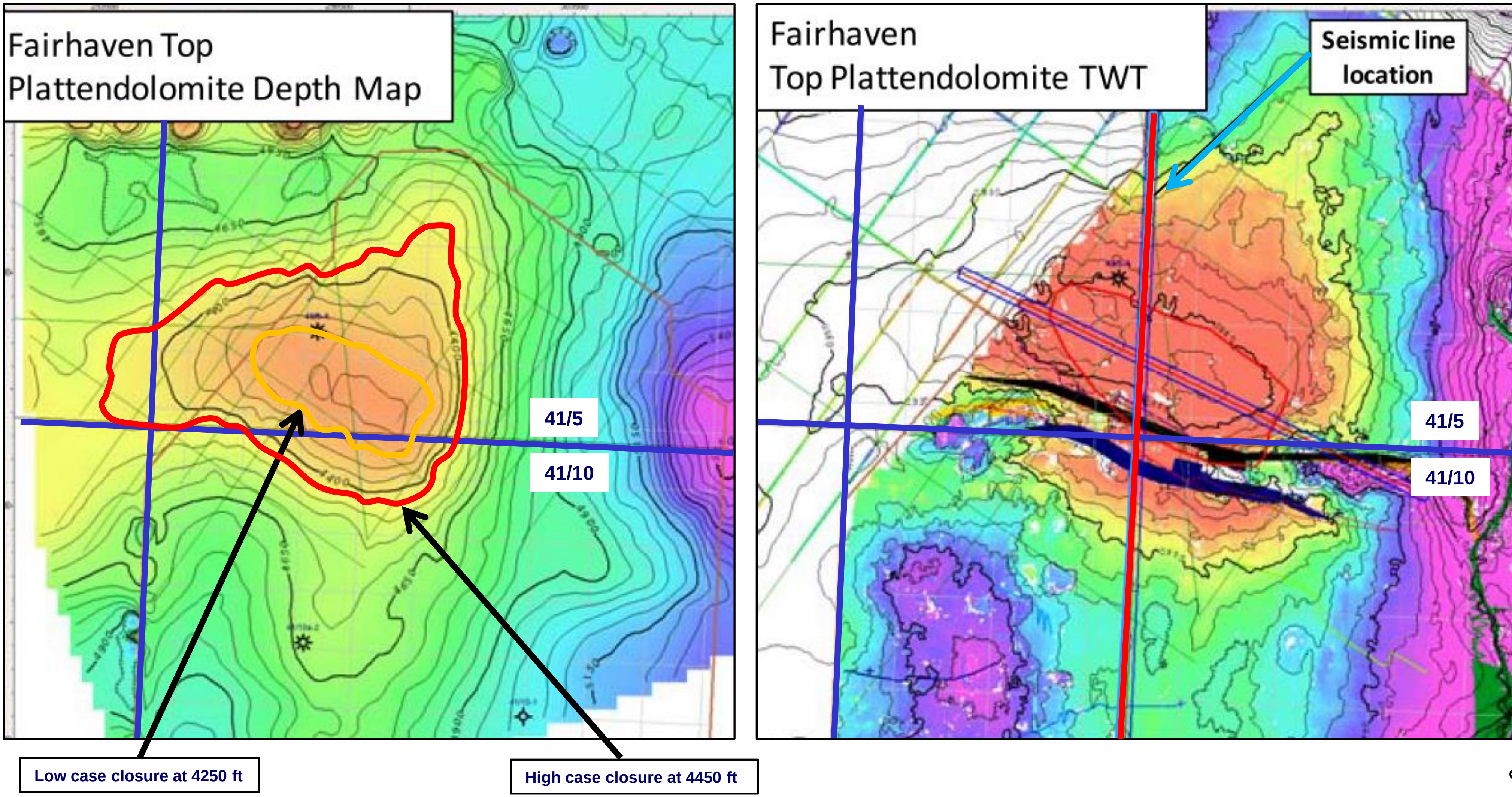


Figure 2.7

Source: CPR on Trap Oil, Challenge Energy

Well 41/10a-2/2z, Log evaluation

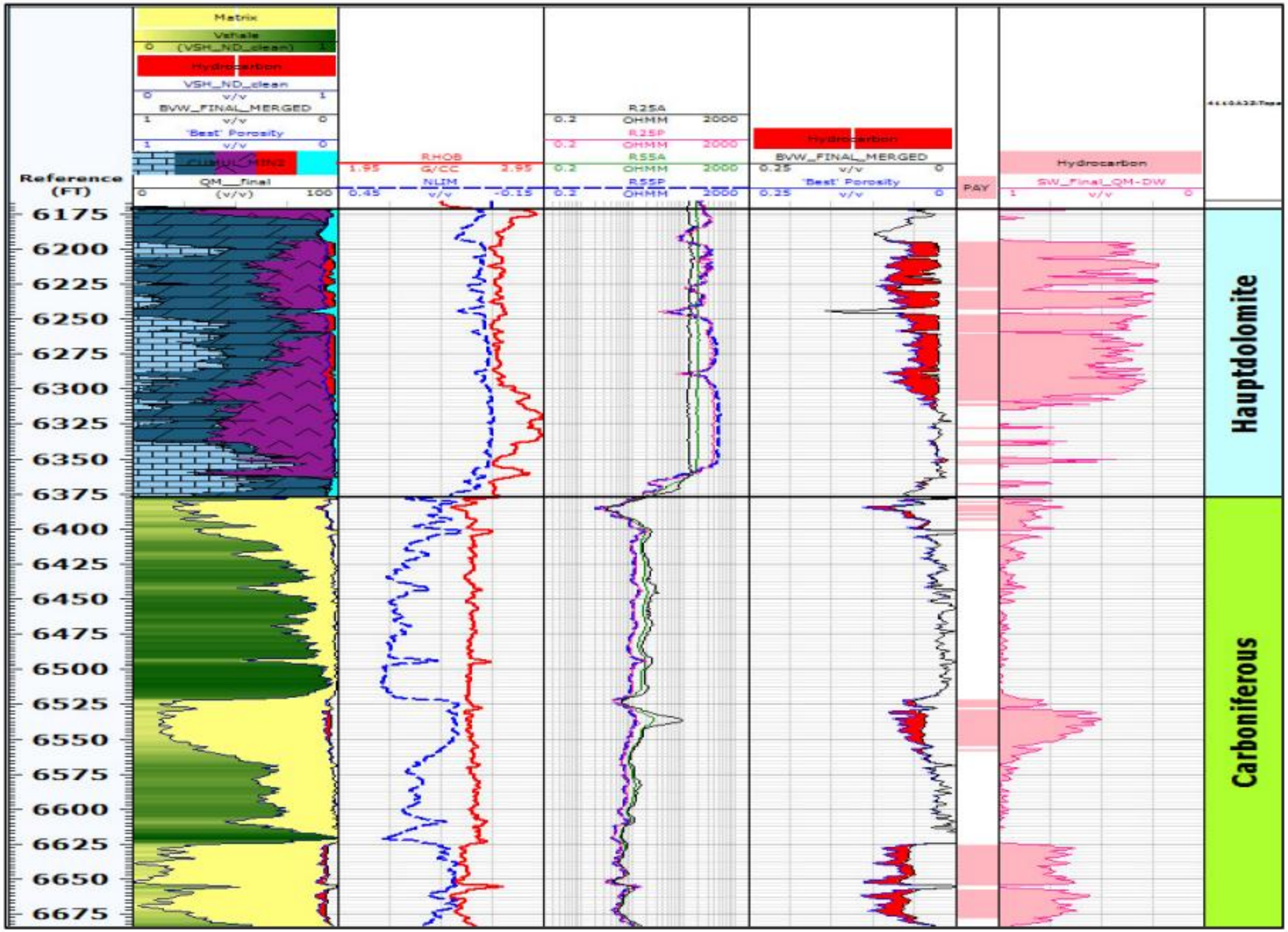


Figure 2.8

Source: Licence P1129 Relinquishment Report, Wintershall

P2252: Prospects and Lead Locations

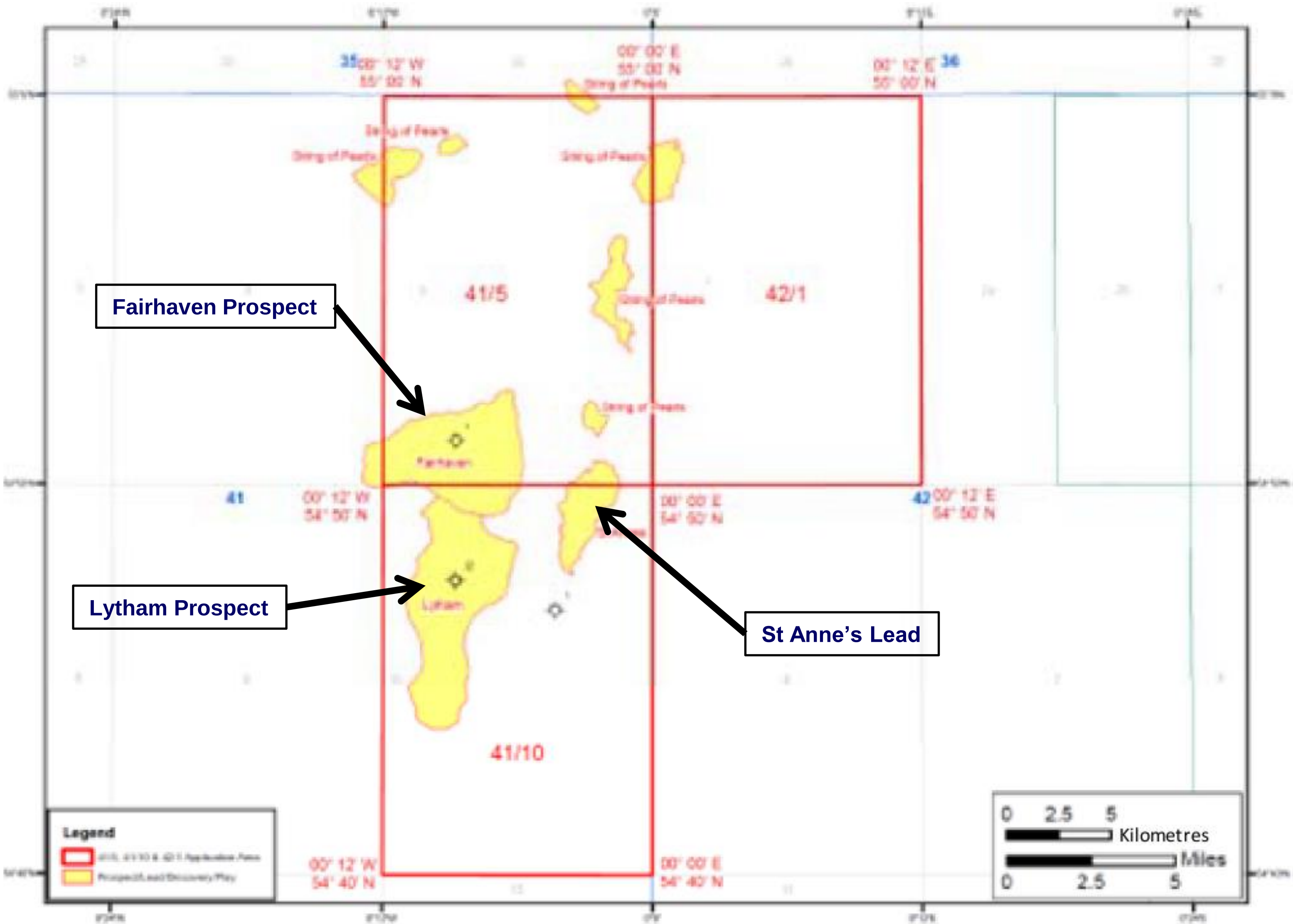


Figure 2.9

Source: CPR on Trap Oil, Challenge Energy

Seismic Line through the Fairhaven Prospect

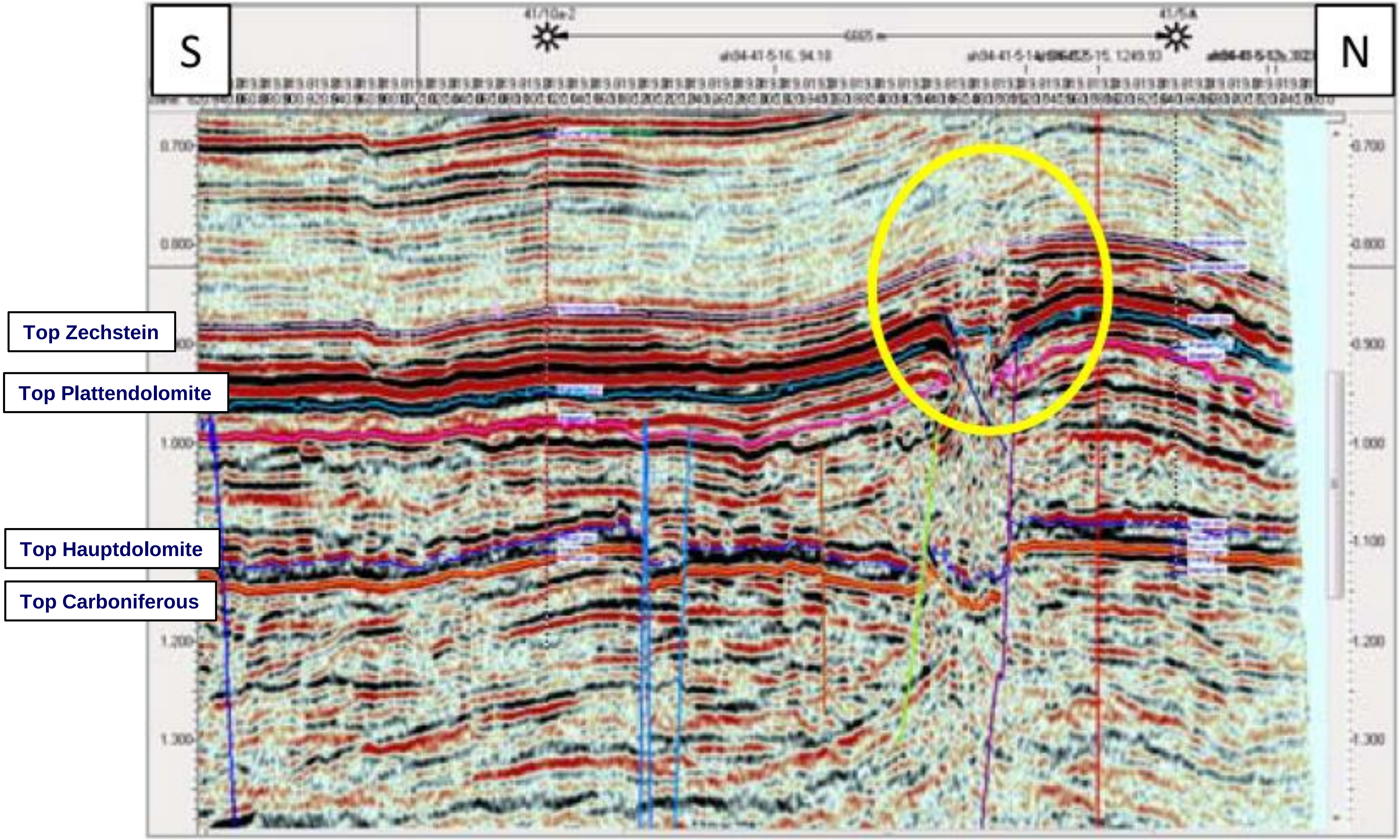
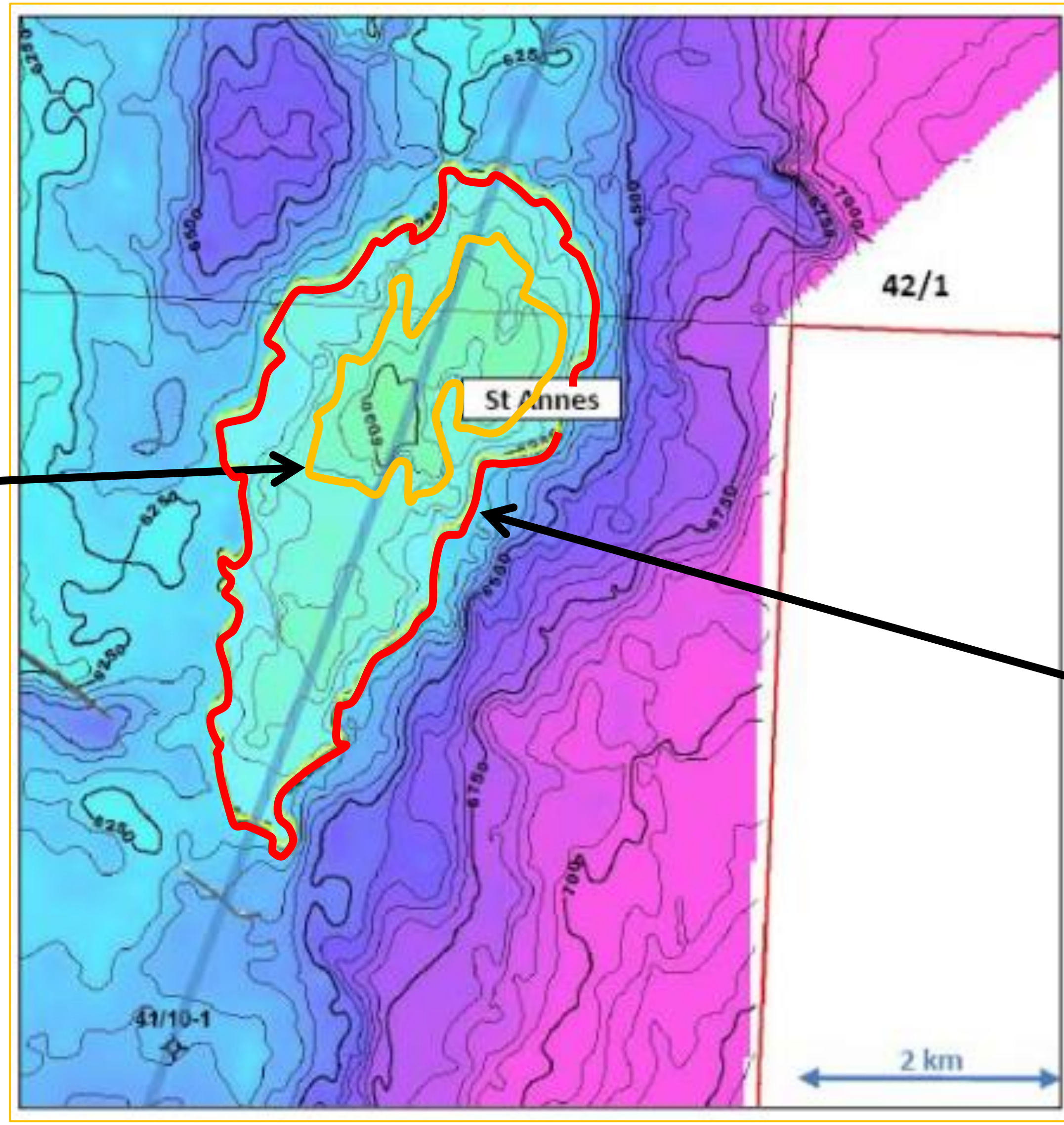


Figure 2.10

Source: Licence P1129 Relinquishment Report, Wintershall

St Anne's Lead: Top Carboniferous Depth Map



Source: CPR on Trap Oil, Challenge Energy

Block 42/10: Seismic Line through Well 41/10-2 and St Anne's Lead

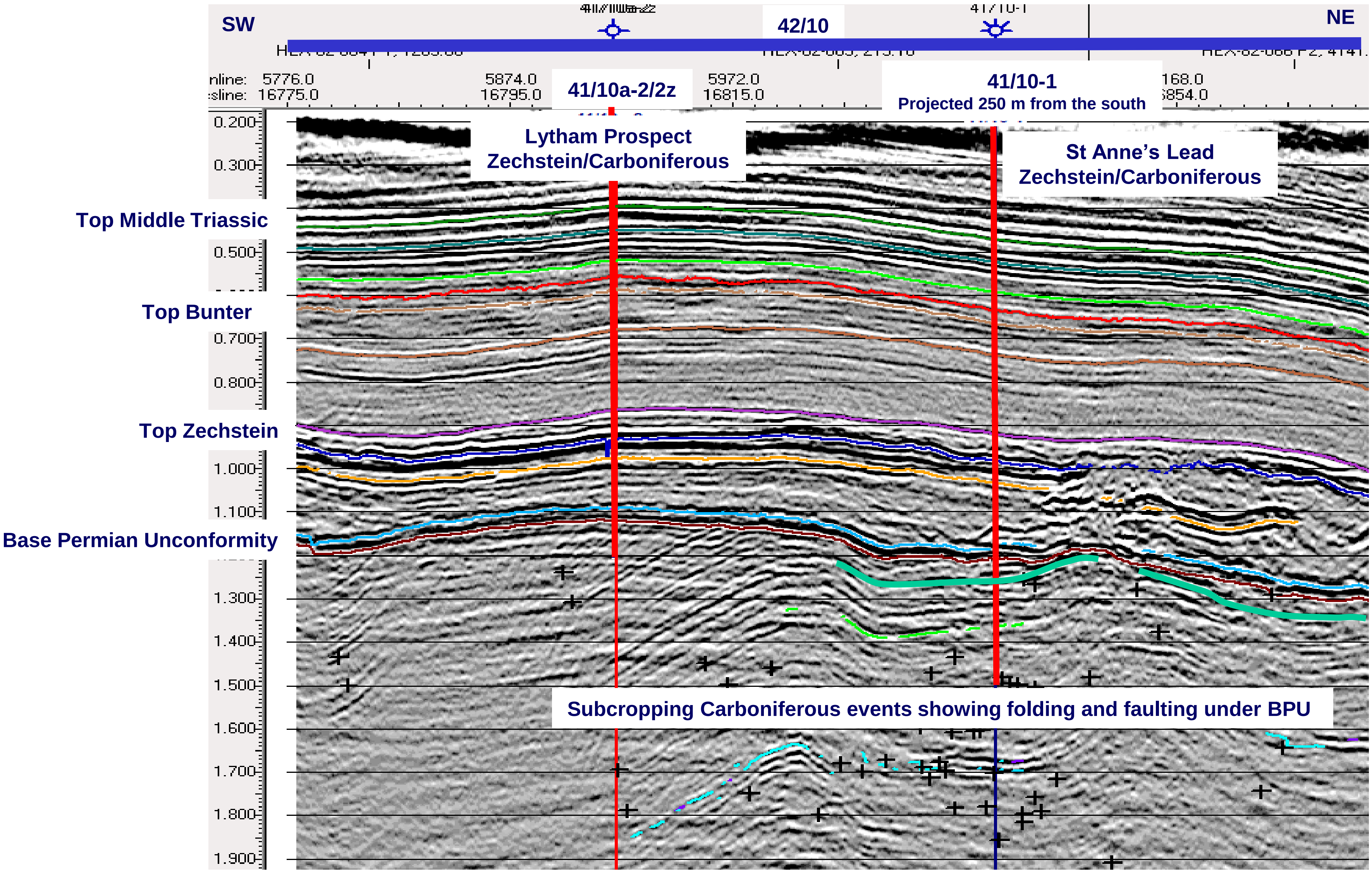
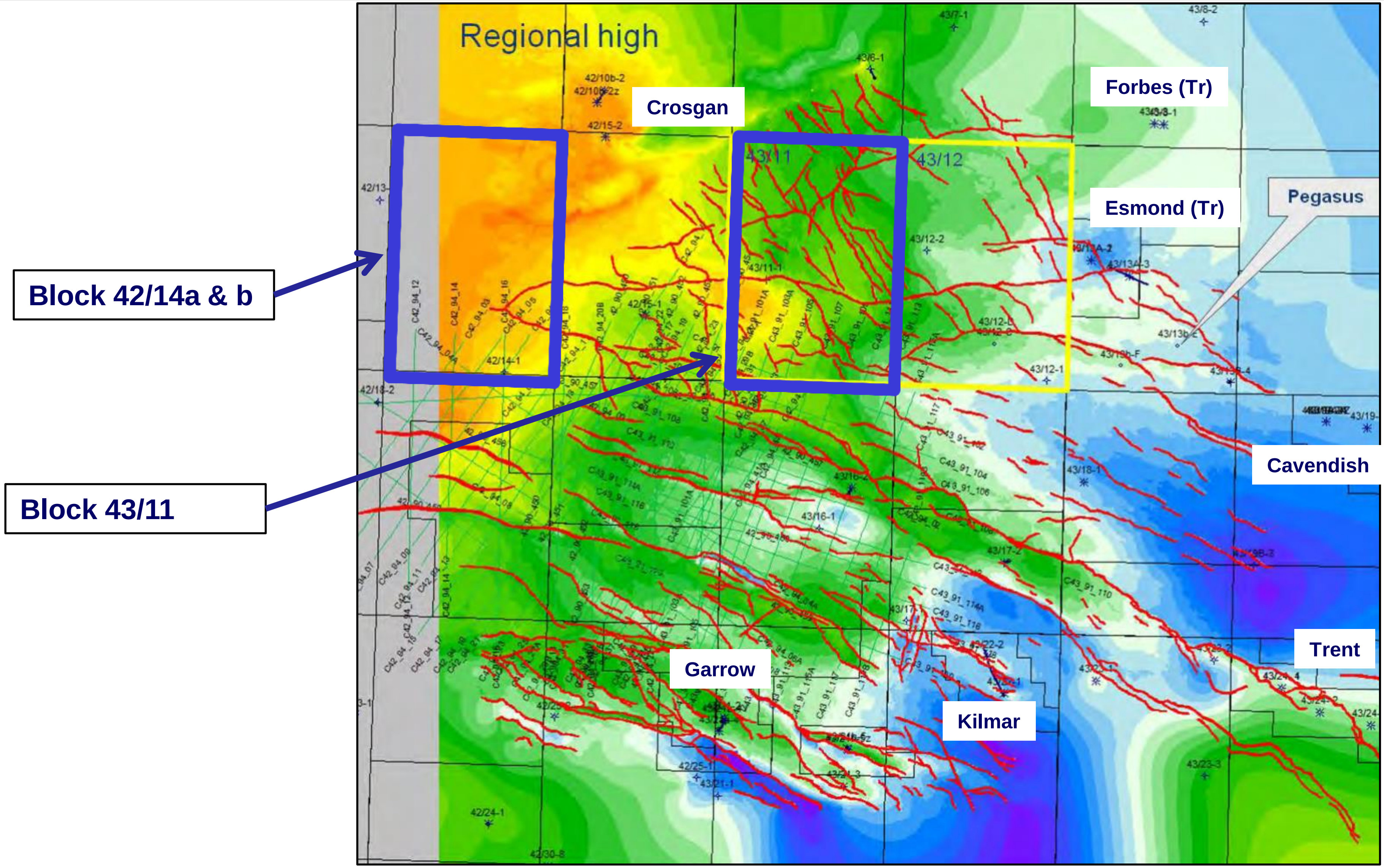


Figure 2.12

Blocks 42/14 and 43/11 Area: Regional Depth to Base Permian Unconformity Map

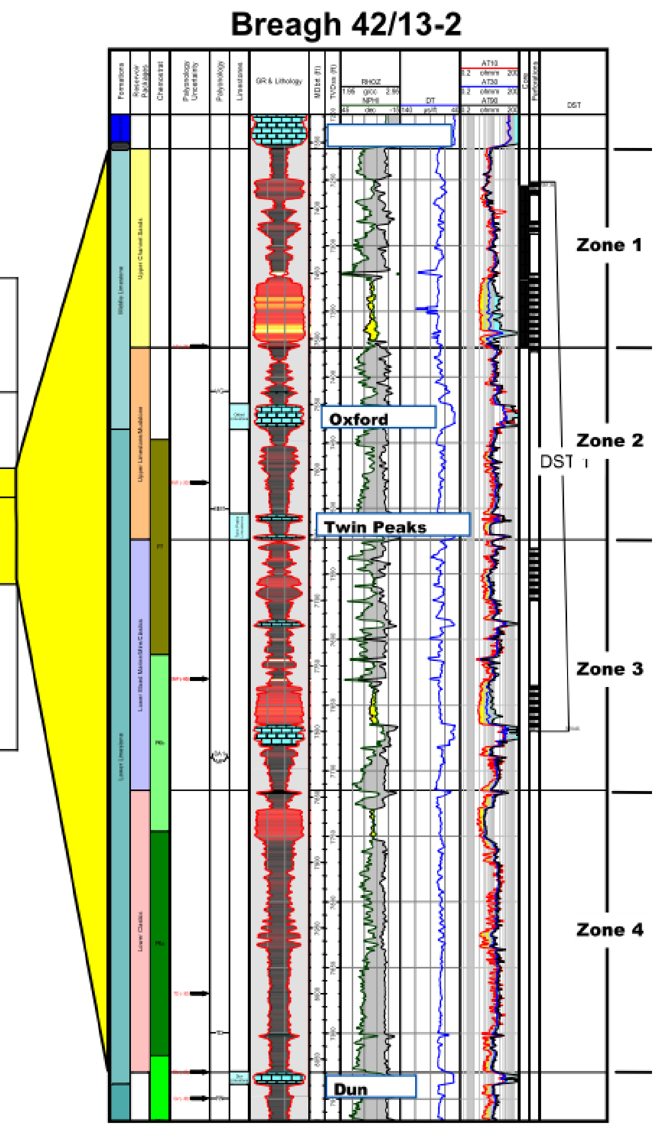


Source: P1334 Relinquishment Report, Centrica

Figure 3.1

Breagh Field, 42/13-2 (Lower Carboniferous Yoredale Sandstone Reservoir)

Chronostratigraphy		Lithostratigraphy (Onshore)		Lithostratigraphy (Mid North Sea High)		Limestone Marker Beds	Breagh Reservoir Zones
Stage	Substage	Group	Formation	Group	Formation		
Namurian	Arnsbergian	Yoredale	Alston	Farne	Upper Limestone		
	Pendleian					Great Limestone	
Visean	Brigantian		Tyne Limestone		Middle Limestone		Zone 1
						Oxford Limestone	Zone 2, 3 & 4
					Lower Limestone	Dun Limestone	
	Asbian				Scremerston		
	Holkerian	Border	Fell Sandstone		Fell Sandstone		
	Arundian						
	Chadian						
Tournasian	Courceyan		Cementstone		Cementstone		



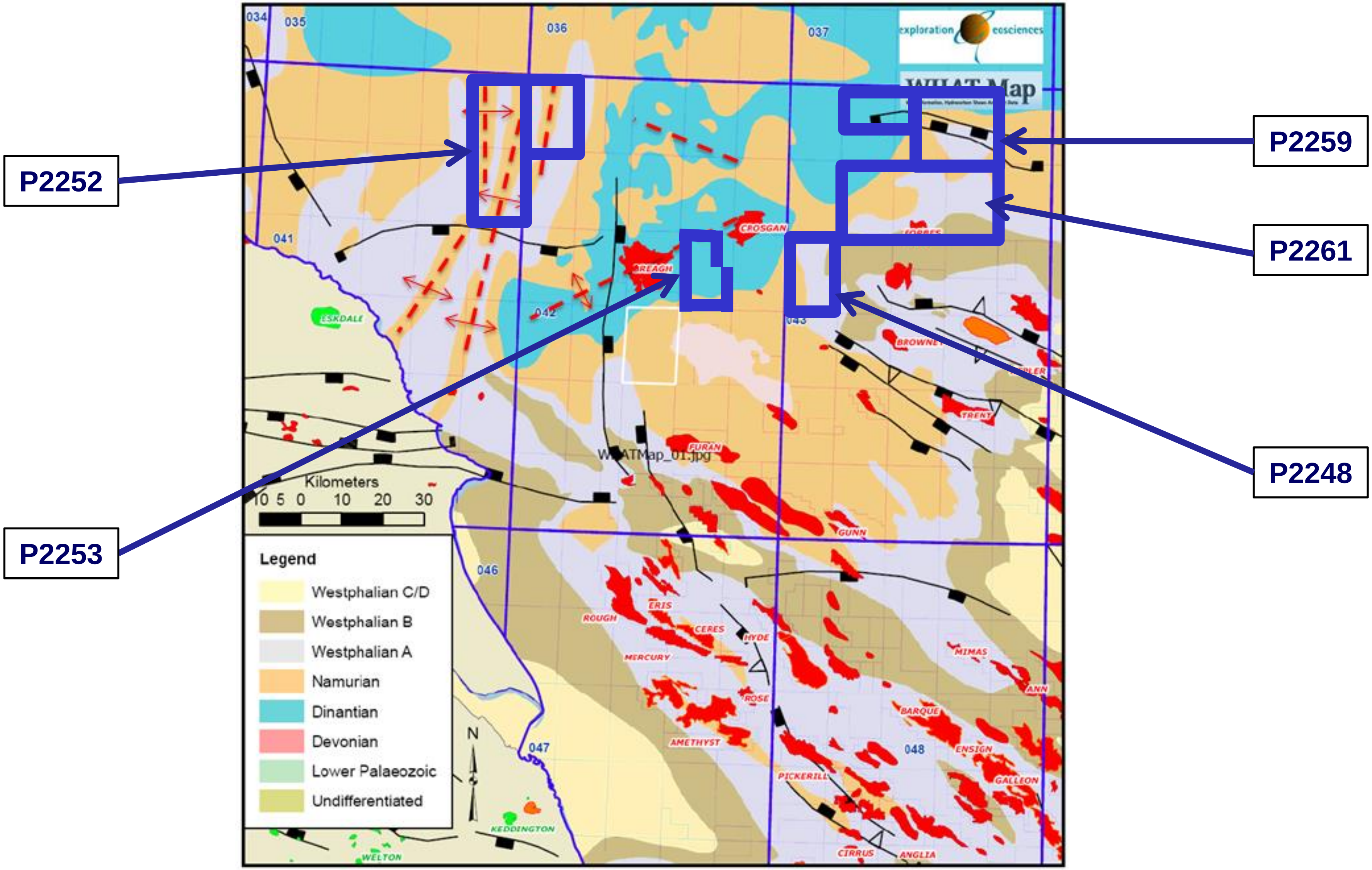
Reservoirs
Channel Sandstones in the late Visean & Lower Namurian (Low NG)

Source Rocks
Namurian-Westphalian shales and coals in Silverpit Basin

Top Seal
Zechstein evaporites (Proven) and intra-Carboniferous shales (Unproven)

Figure 3.2

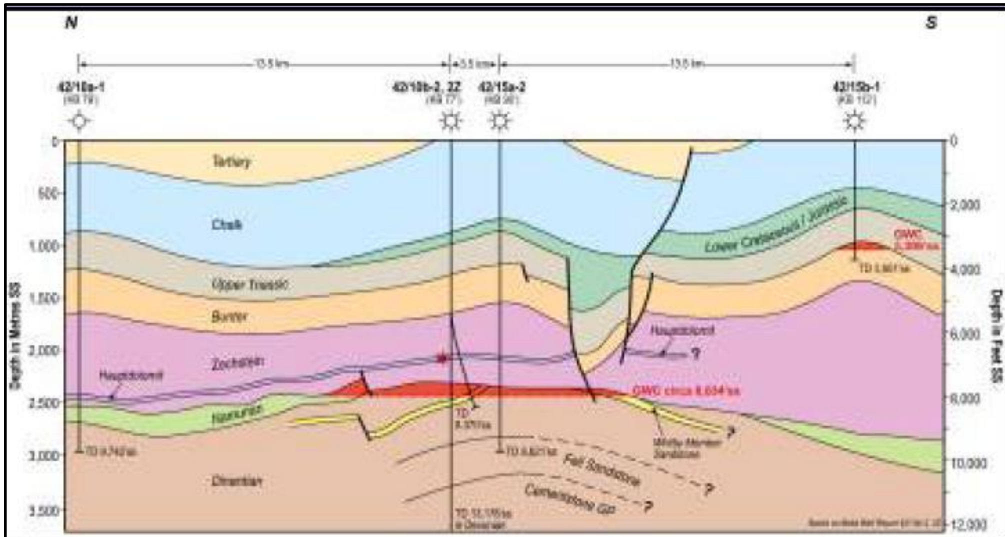
Carboniferous Subcrop to Base Permian Unconformity

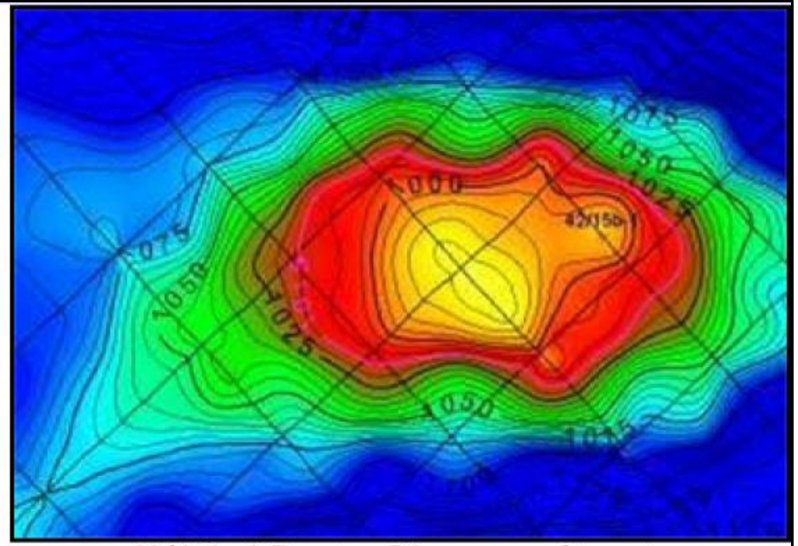


Source: CNR

Figure 3.3

Triassic Discovery, 42/15b-1(Bunter Sandstone Reservoir)





42/15b-1 Bunter Discovery Structure

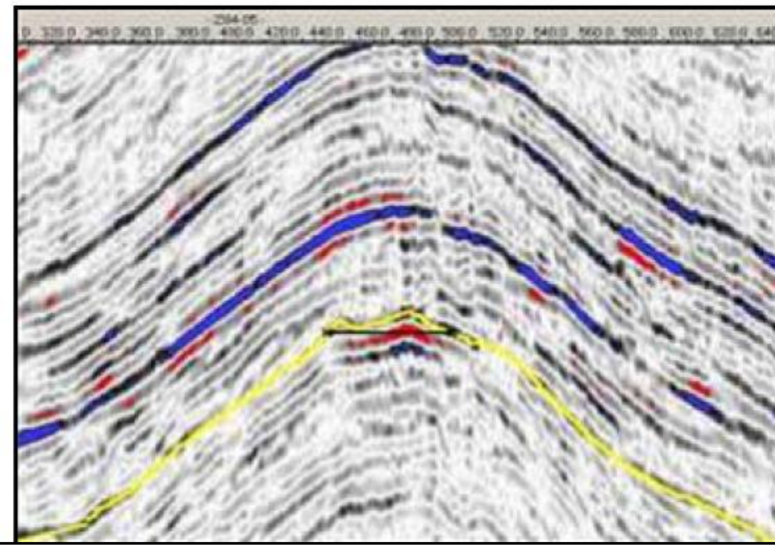


Figure 3.4

Blocks 42/14b and 43/11: Seismic Line through Wells 42/15b-1 and 43/11-1

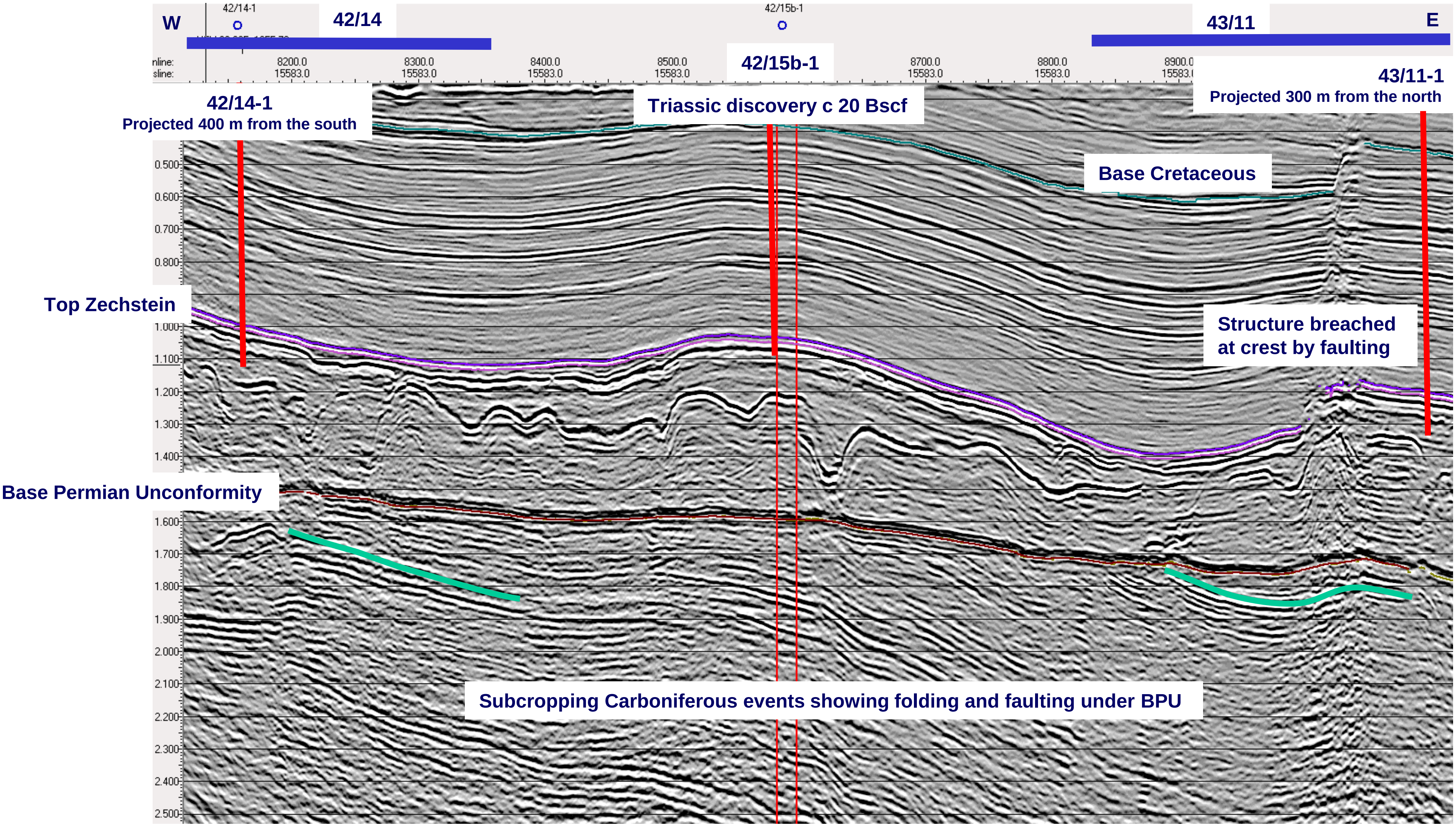
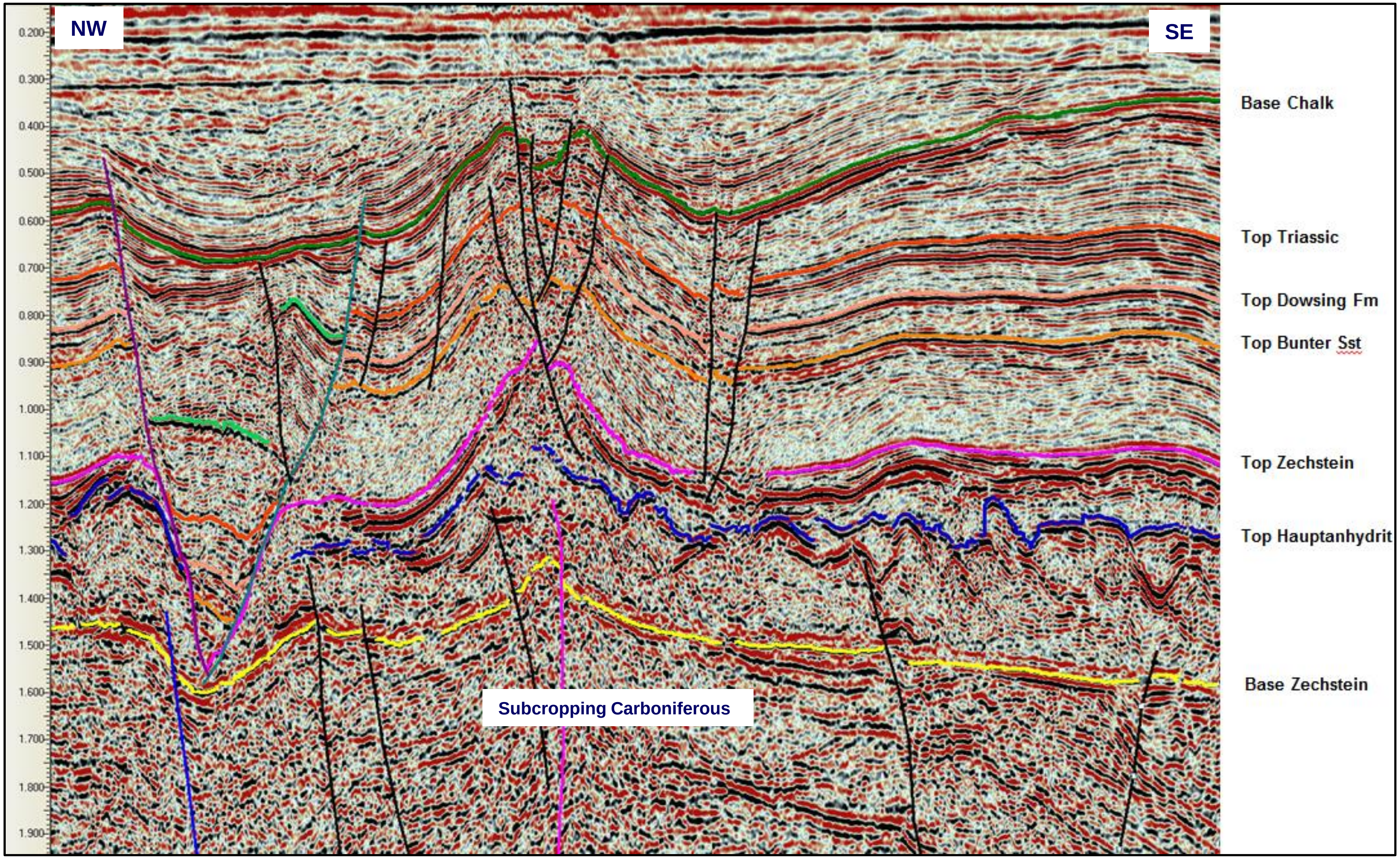


Figure 3.5

Source: CNR Kingdom Project

Block 42/14b: Example of 2D Seismic Line



Source: CNR

Figure 3.6

Breagh Field, 42/13-2 Log Interpretation (Lower Carboniferous Yoredale Sandstone Reservoir)

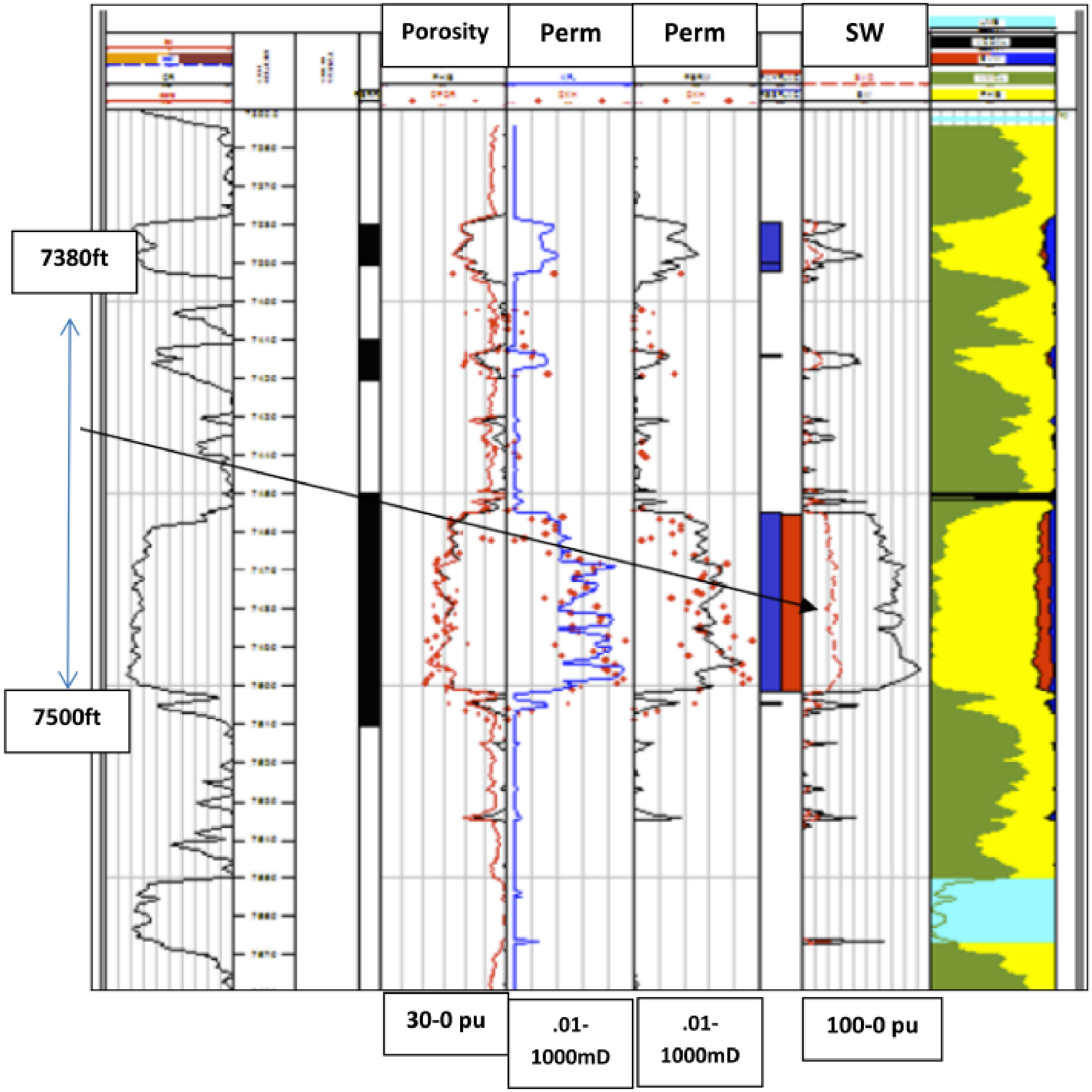
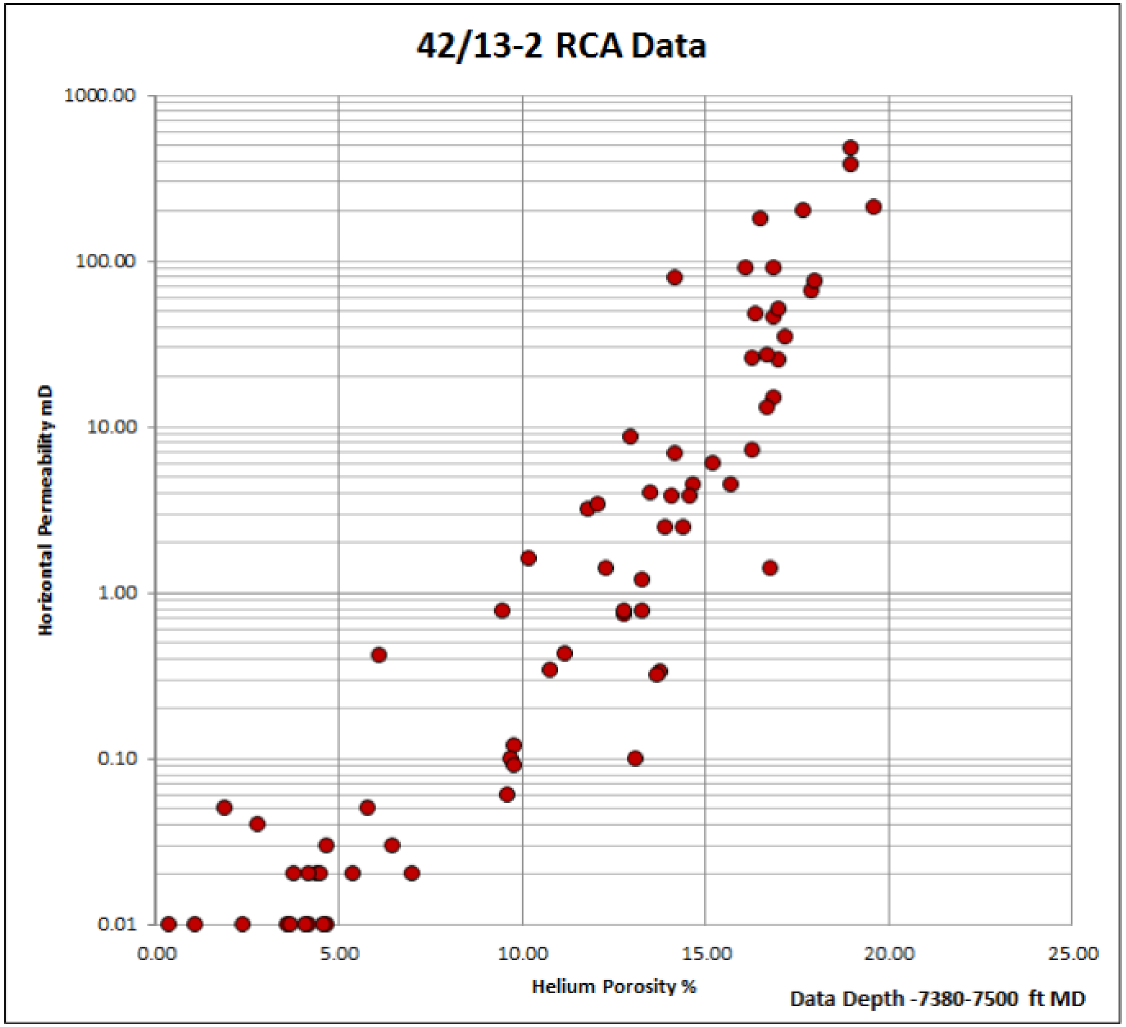
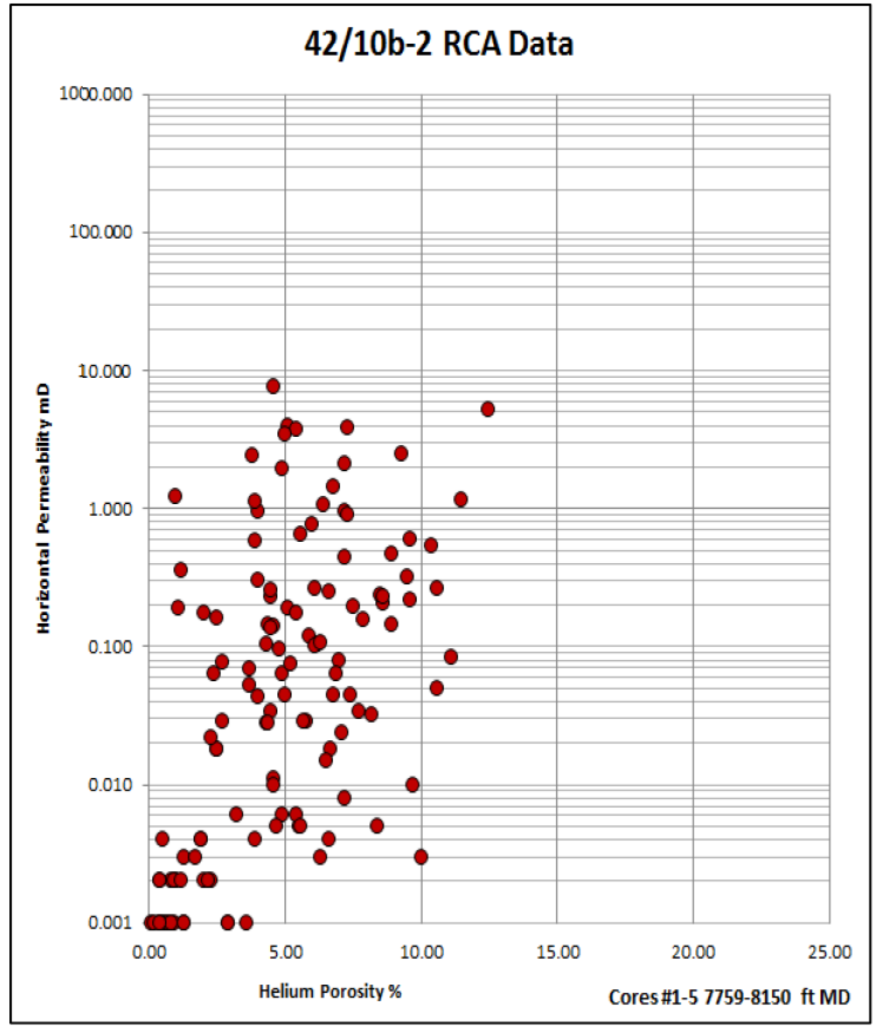


Figure 3.7

Dinantian Yoredale Sandstone Reservoir, Core Poroperm Plots: Breagh and Crosgan Fields



Breagh Field

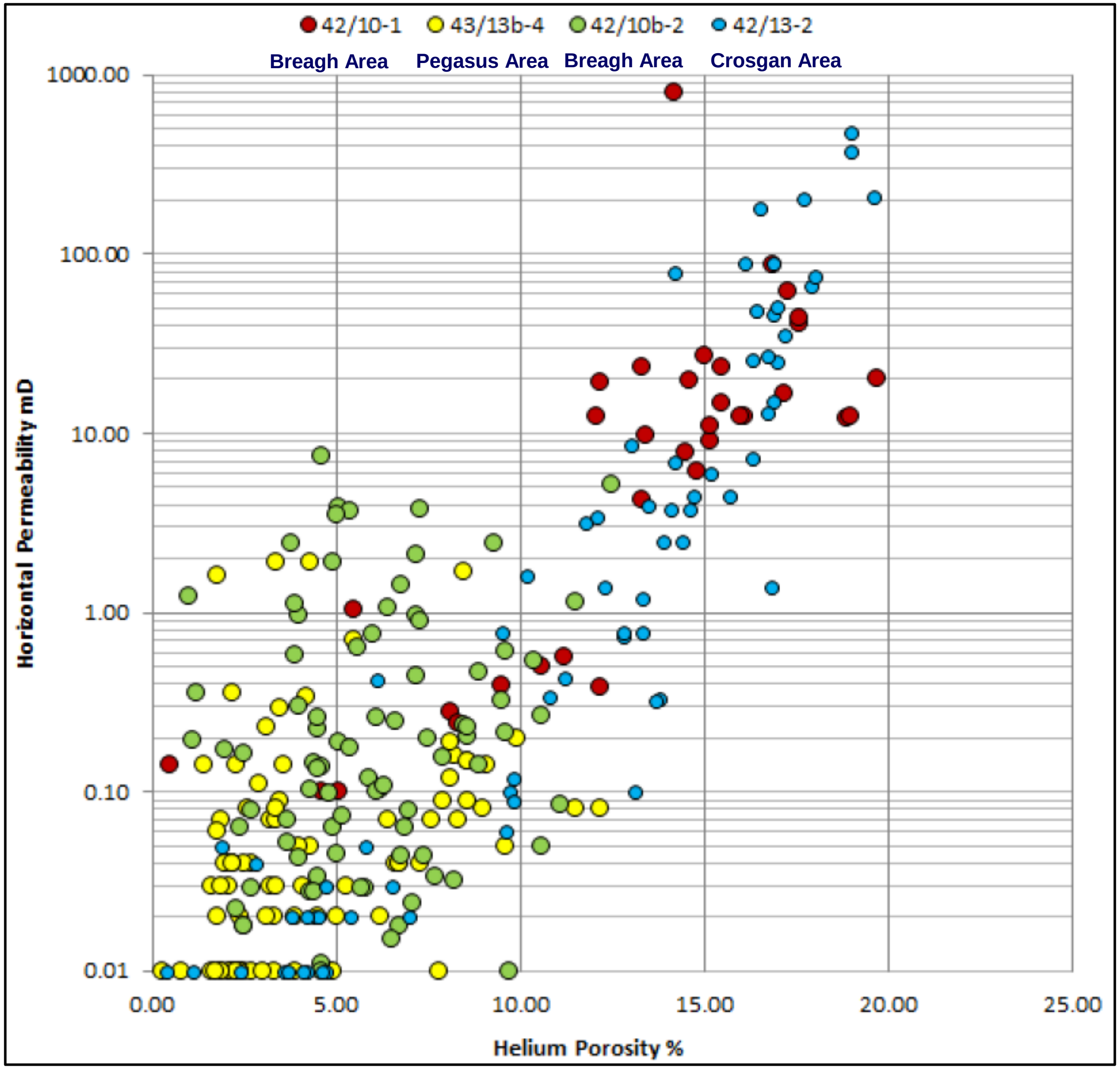


Crosgan Field

Figure 3.8

Source: CNR released core data

Carboniferous Core Data (Northern Sector of Quadrants 42 and 43)



Source: CNR released core data

Figure 3.9

Block 43/11 Area: Regional Depth to Base Permian Unconformity Map

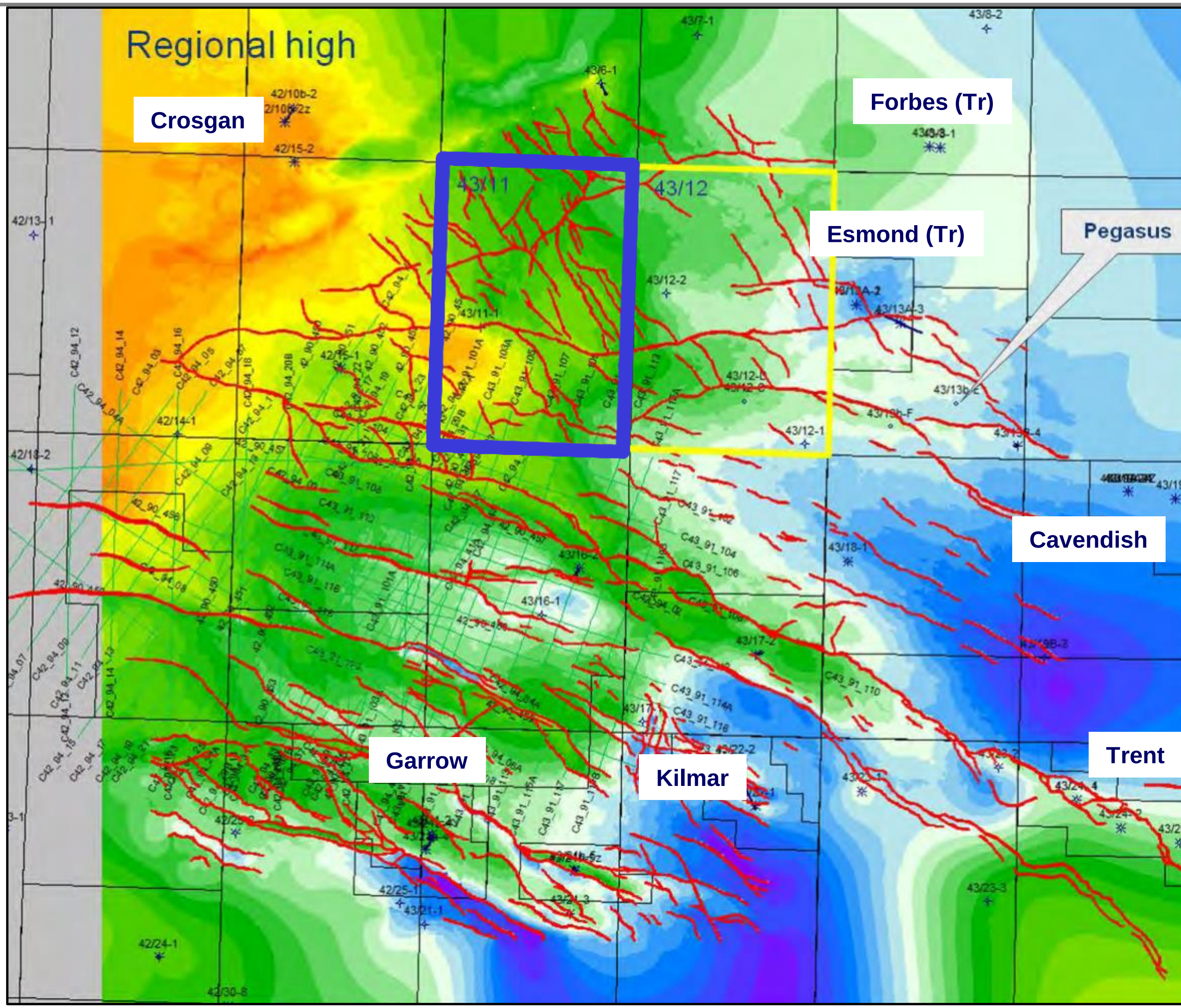


Figure 4.1

Source: P1334 Relinquishment Report, Centrica

Pegasus Discovery, Well 43/13b-6z (Middle Carboniferous Sandstone Reservoir)

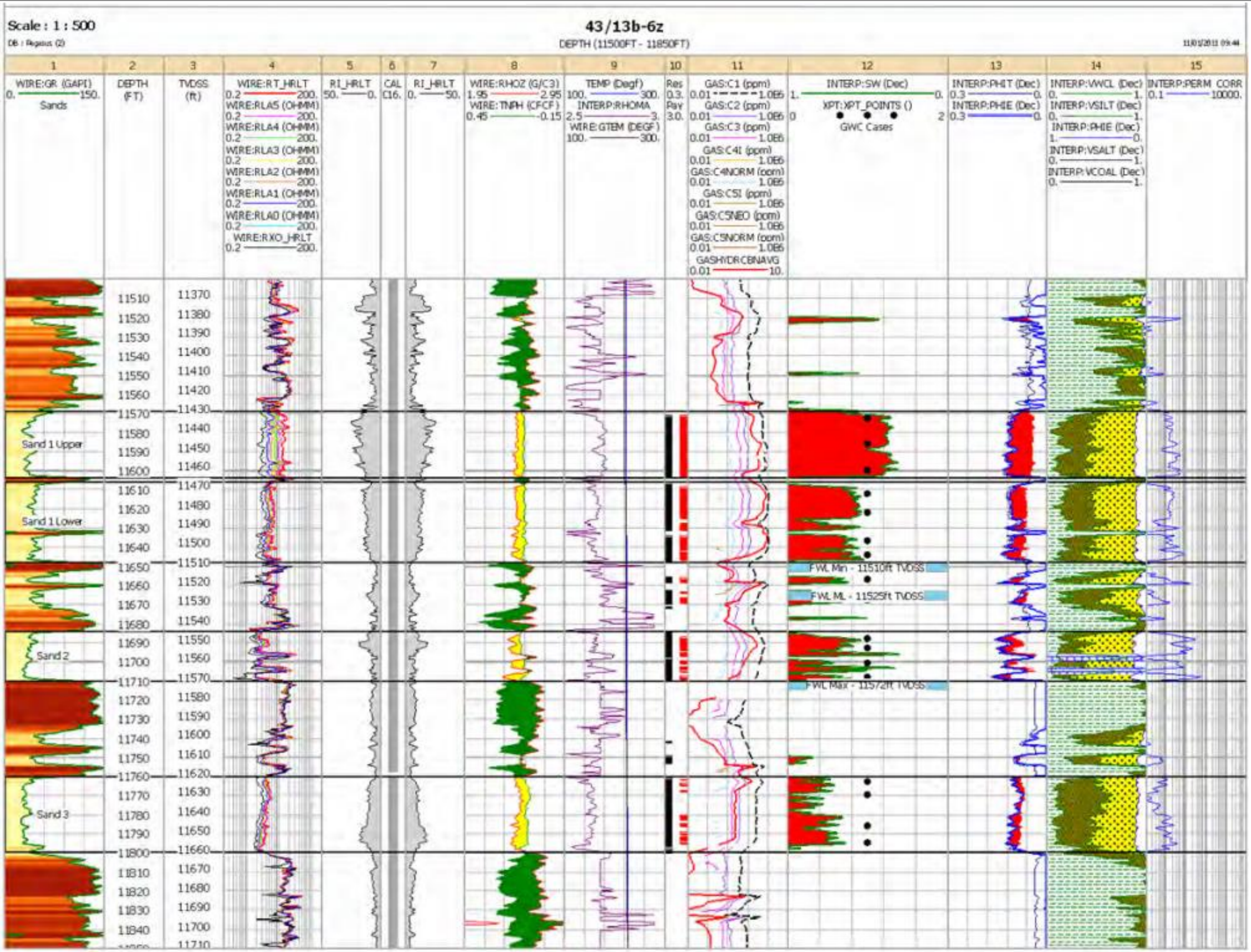


Figure 4.2

Well 43/13b-4 (Middle Carboniferous Sandstone Reservoir)

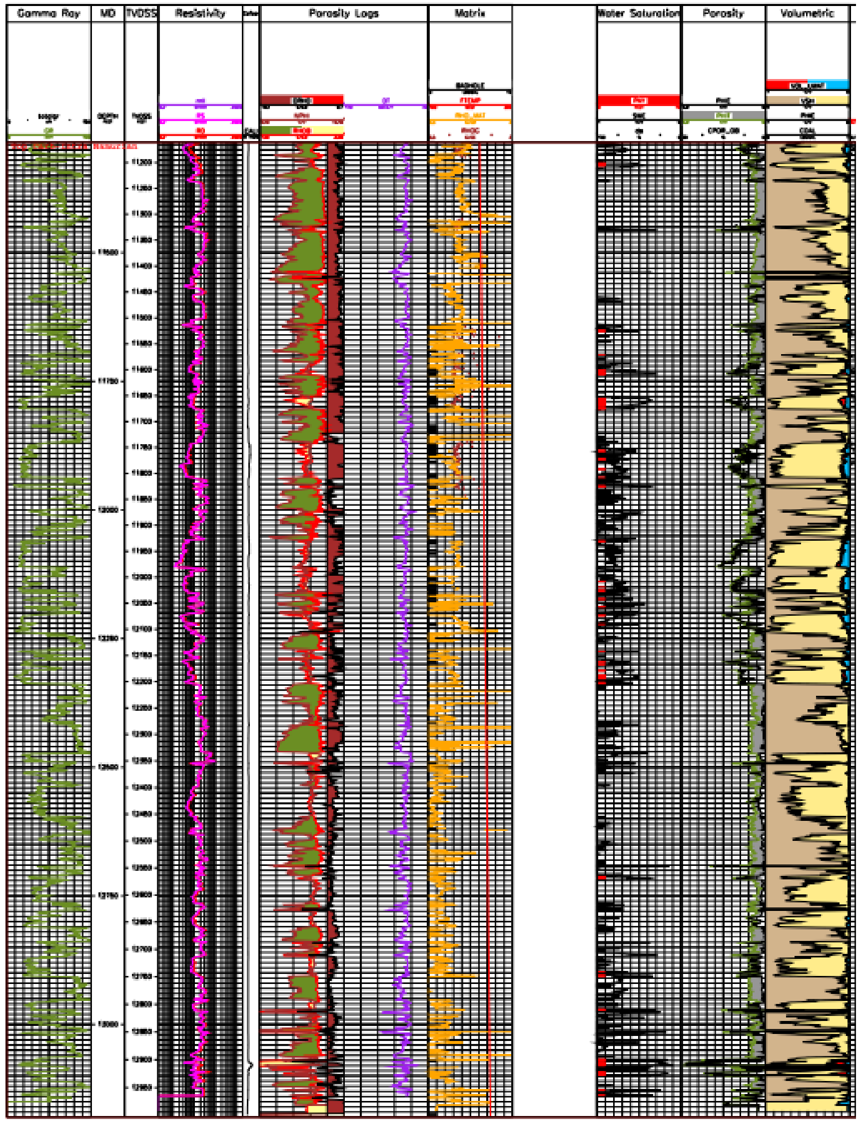


Figure 4.3

Source: P1334 Relinquishment Report, Centrica

Well 43/12-1 (Upper Carboniferous Sandstone Reservoir)

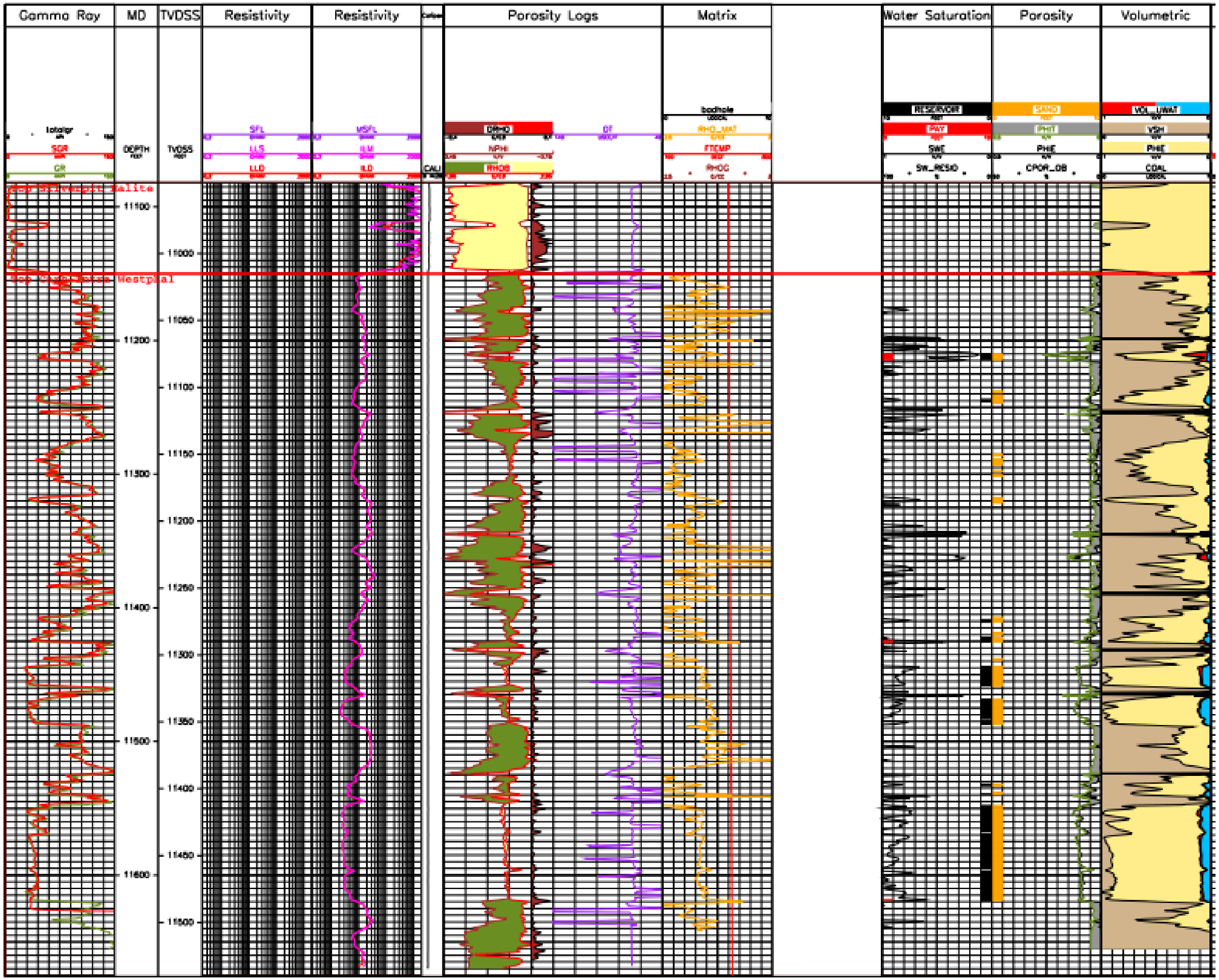


Figure 4.4

Source: P1334 Relinquishment Report, Centrica

Block 43/11 Area: Base Permian Unconformity Map

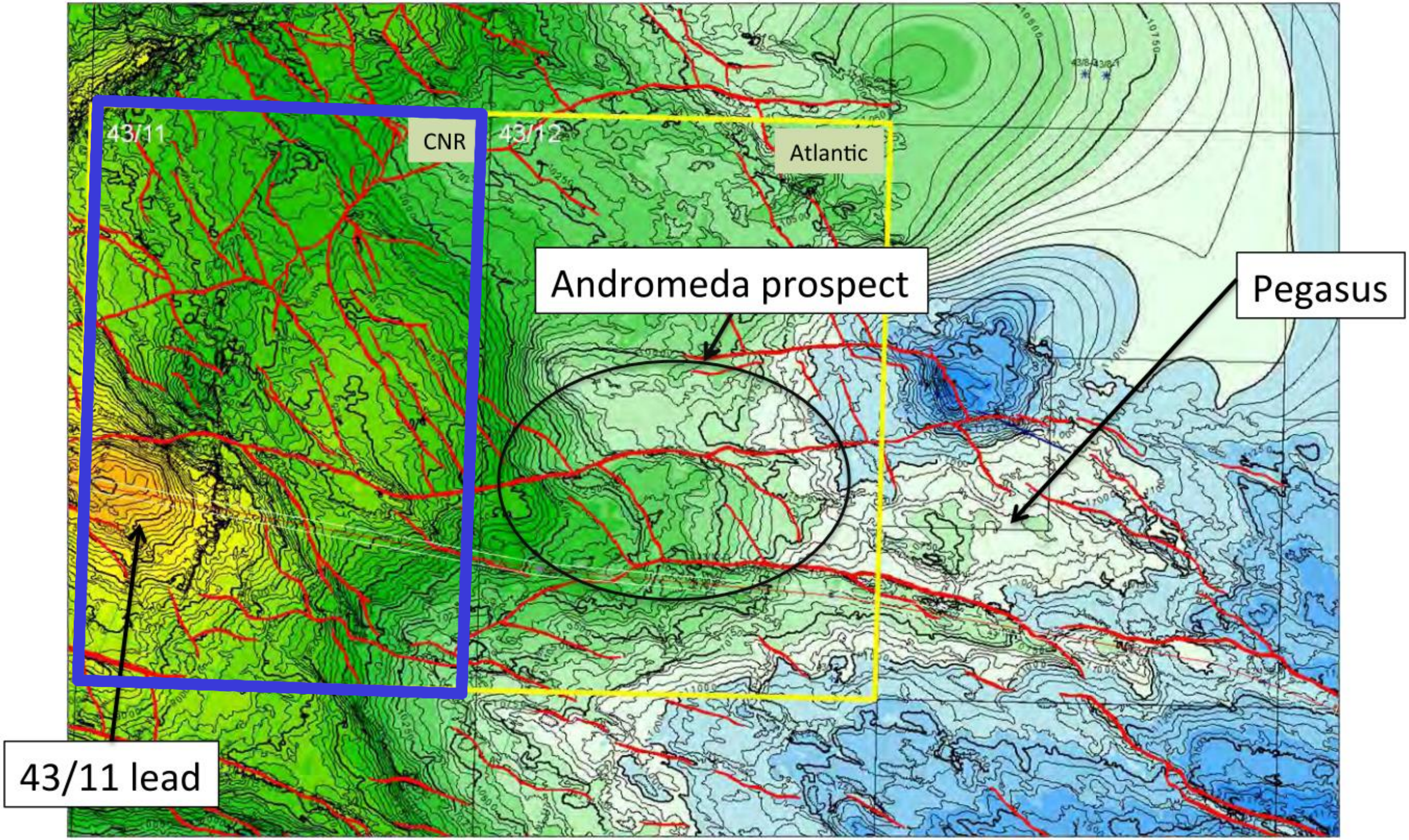
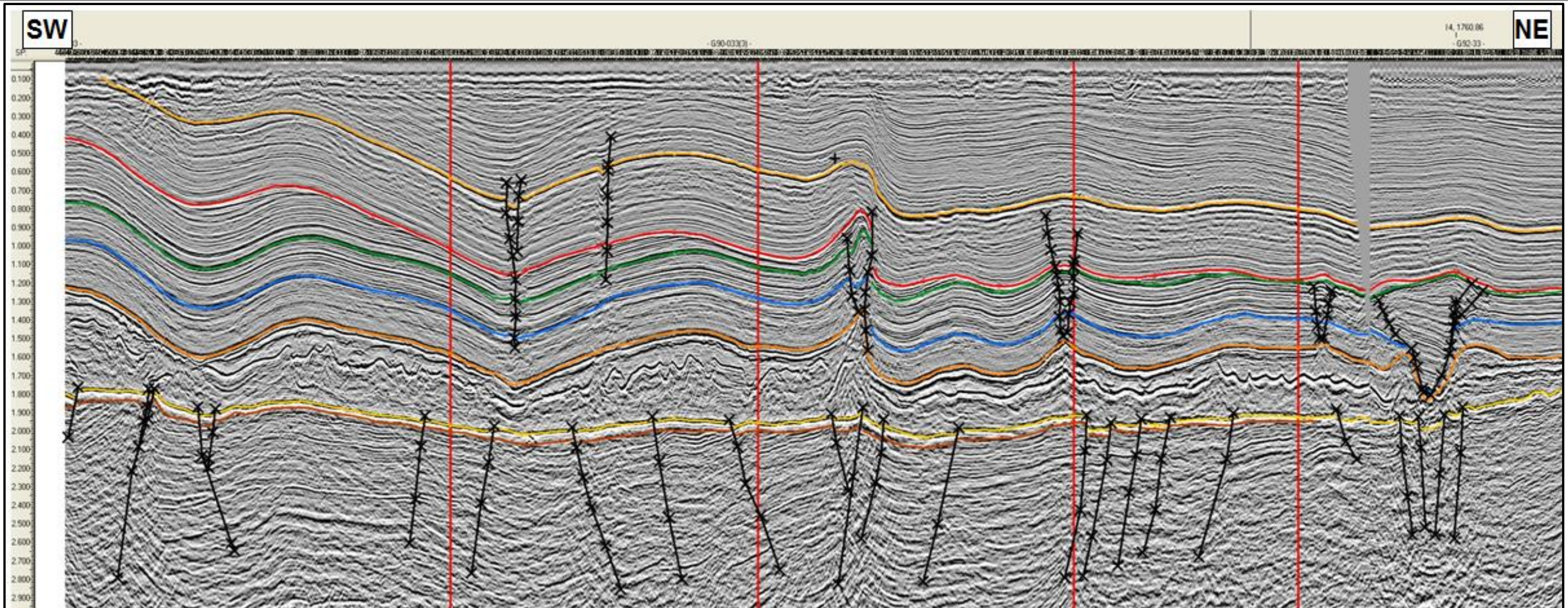
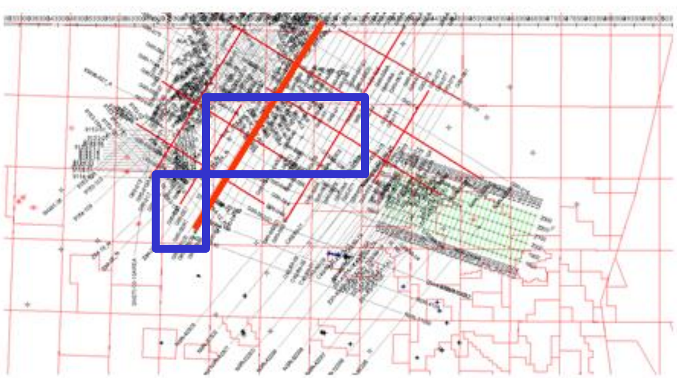


Figure 4.5

Source: P1334 Relinquishment Report, Centrica

Quadrant 43 North: Regional Seismic Line





Benign overburden in southern half of line. Prominent linear salt induced diapiric structure and subsided linear prism of preserved Mesozoic sedimentary sequence interpreted along northern margins of Quadrant 43.

Figure 4.6

Source: CNR (from Novas Oil & Gas Consulting)

Block 43/11: Seismic Line through Wells 42/15b-1 and 43/11-1

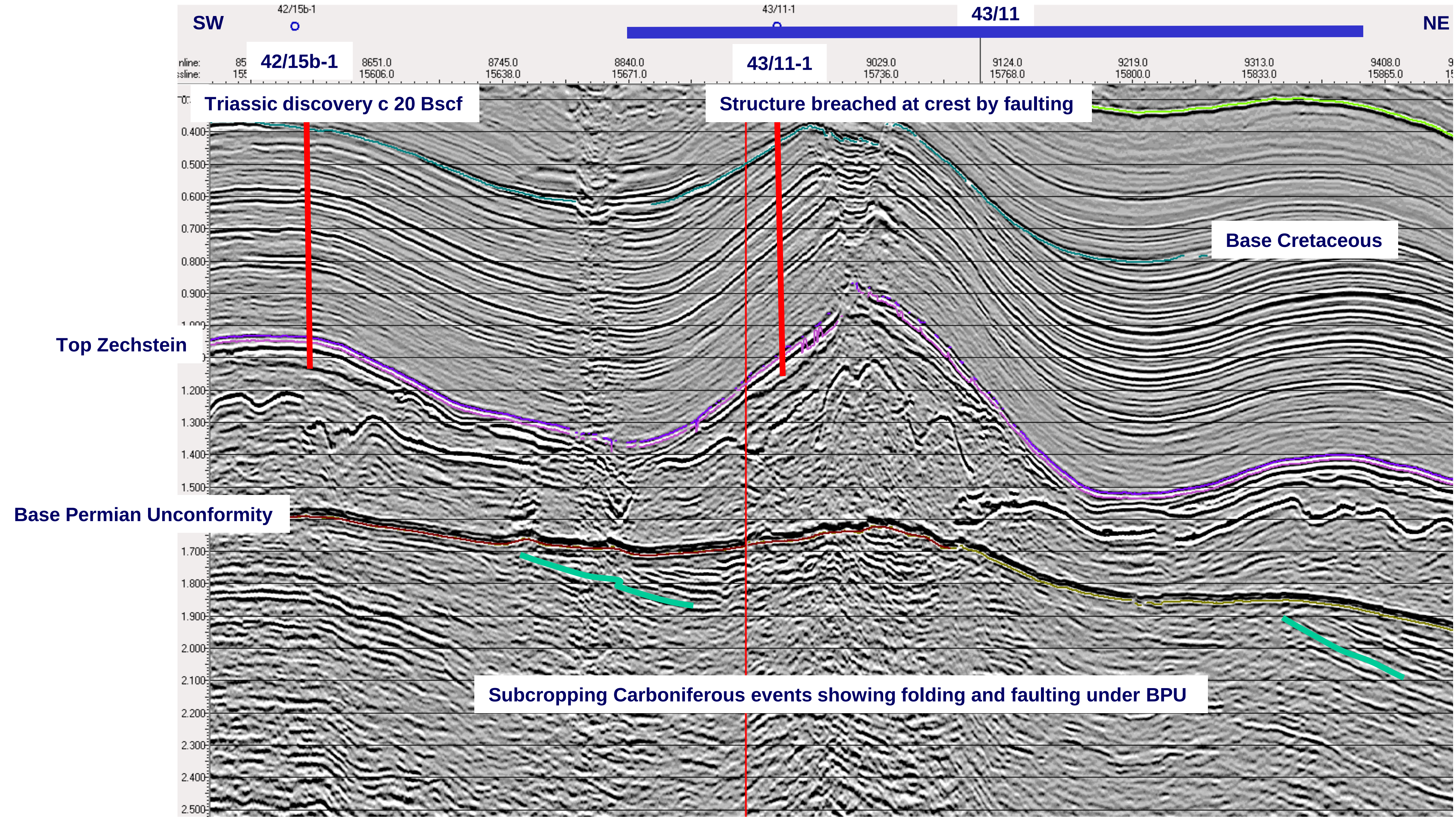


Figure 4.7

Source: CNR Kingdom Project

Pegasus Area, 43/13b-4 (Middle Carboniferous Namurian Sandstone Reservoir)

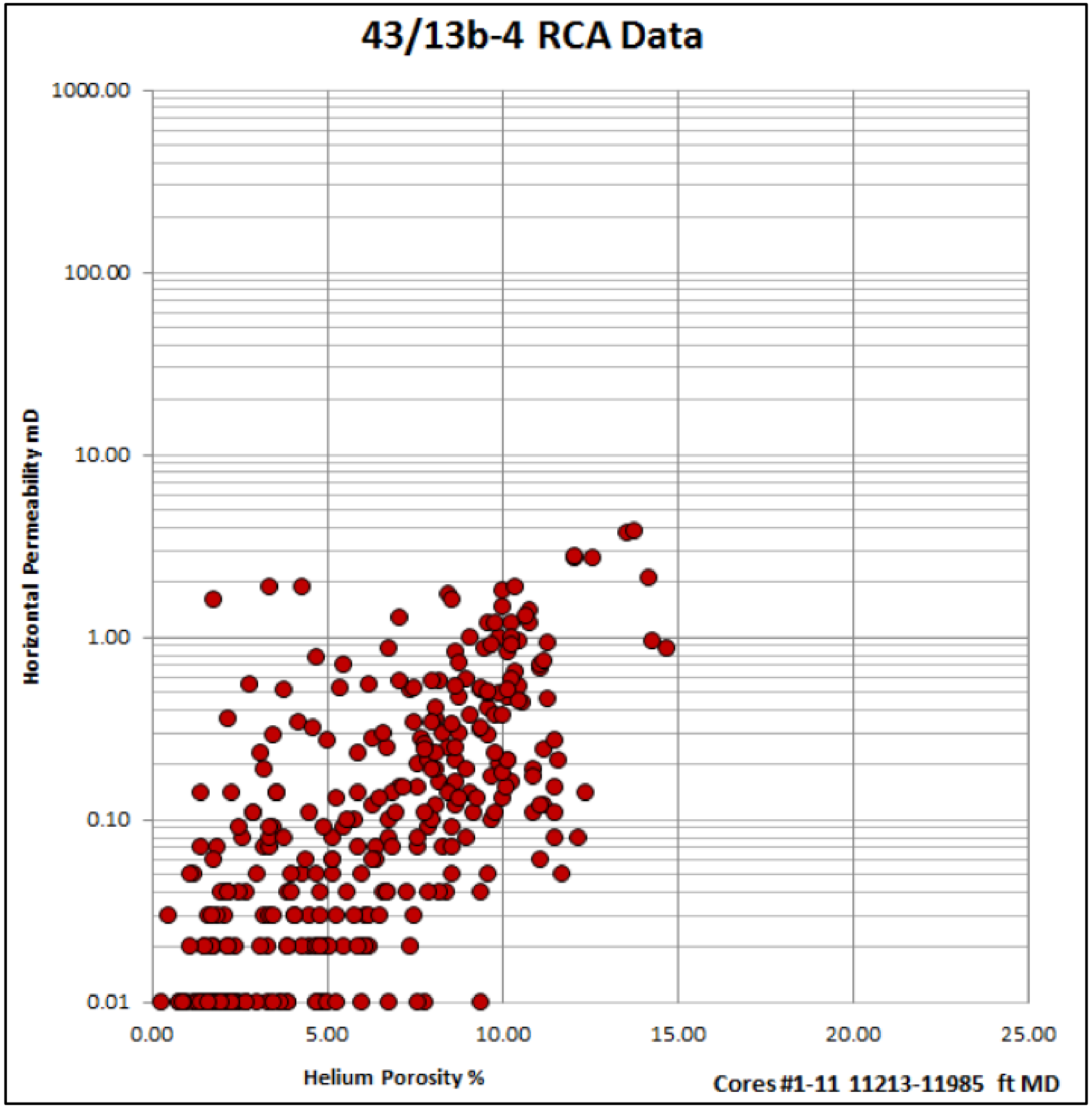


Figure 4.8

Source: CNR released core data

Licence P2261 Area: Regional Depth to Base Permian Unconformity Map

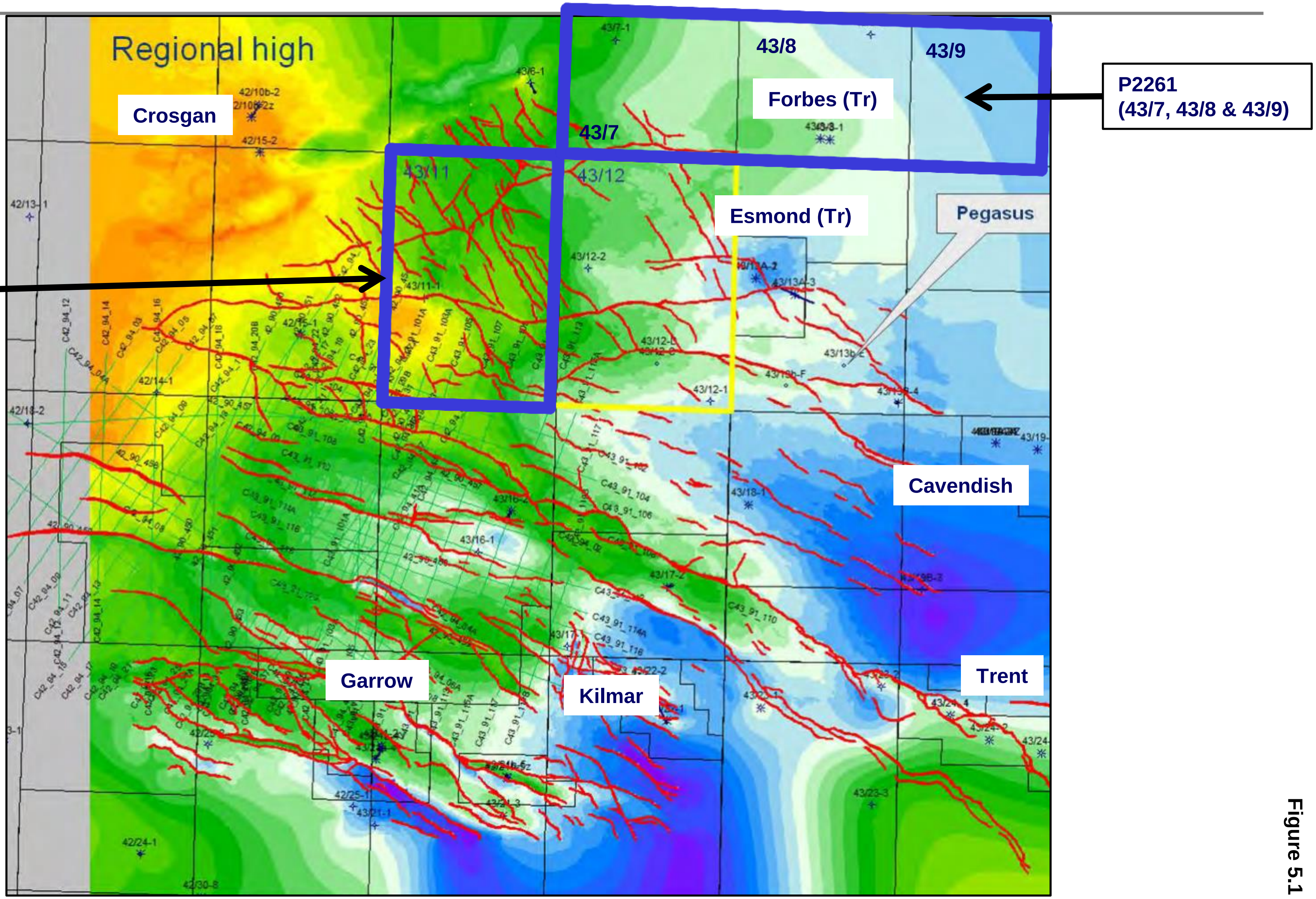


Figure 5.1

Source: P1334 Relinquishment Report, Centrica

Carboniferous Subcrop to Base Permian Unconformity

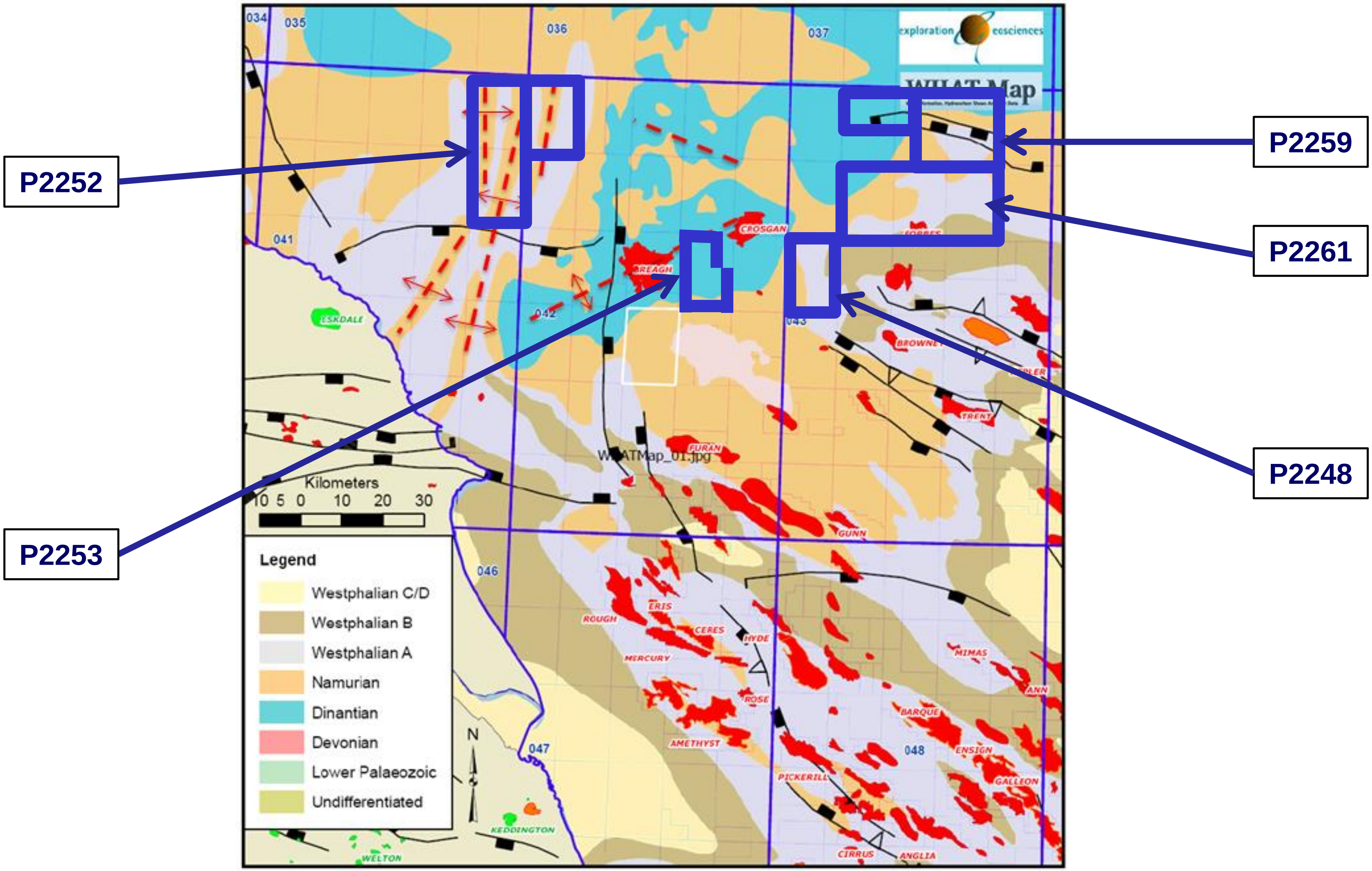


Figure 5.2

Source: CNR

Block 43/7 Area: Example of 2D Seismic Line

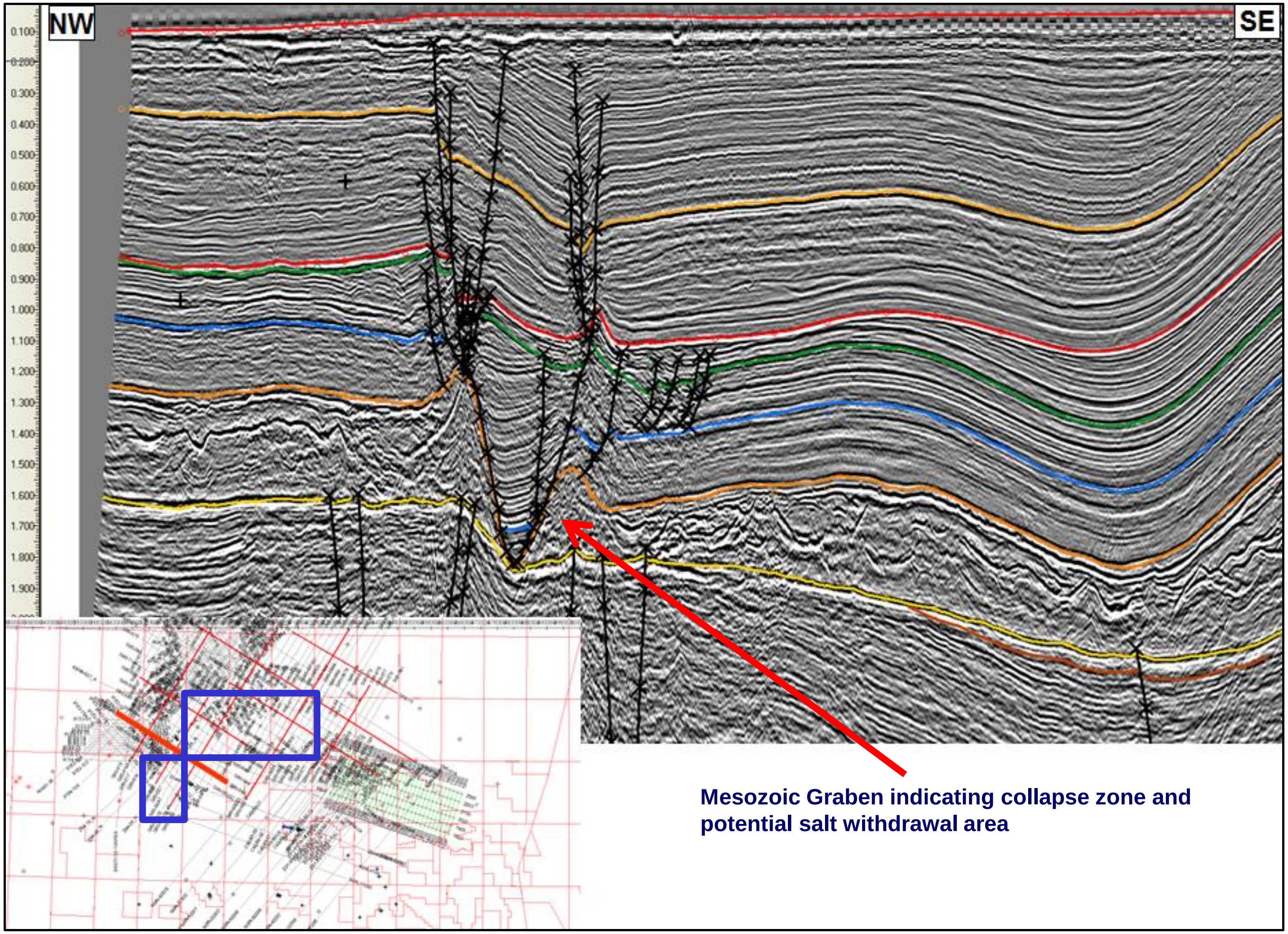
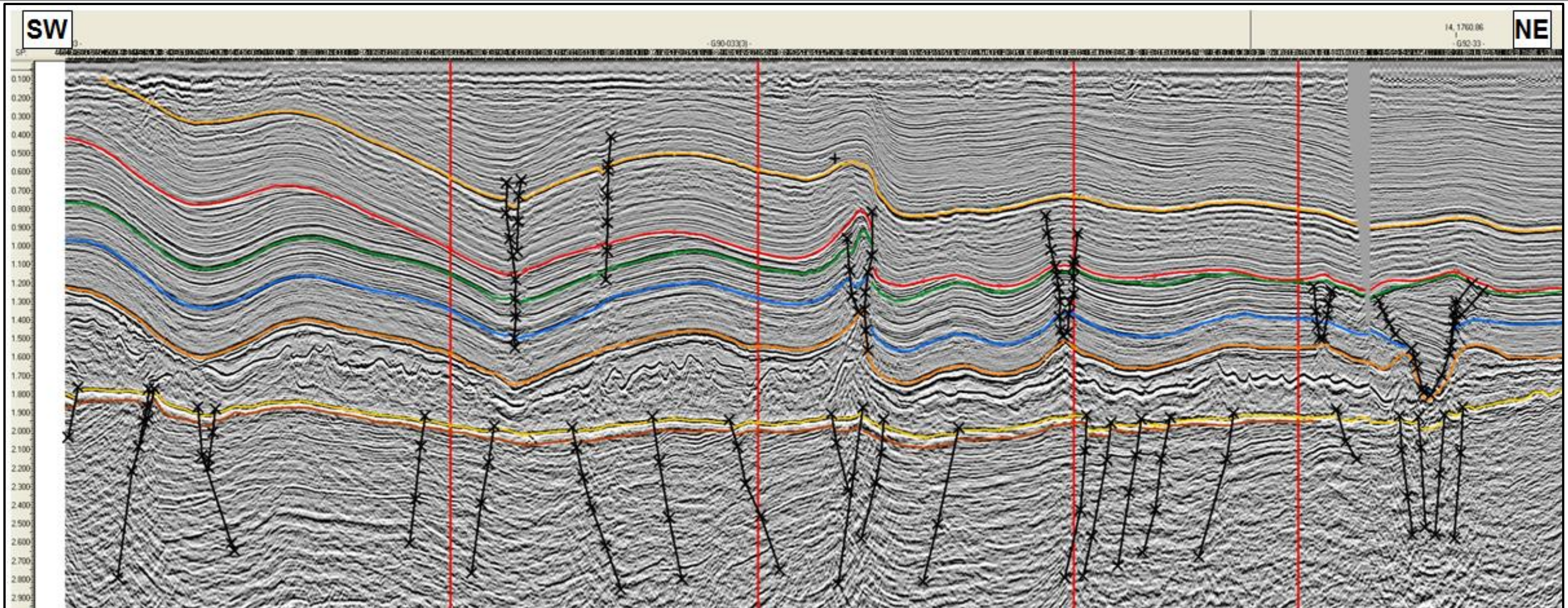
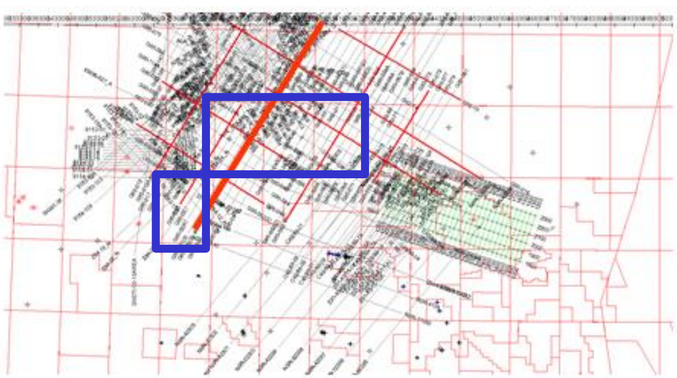


Figure 5.3

Source: CNR (from Novas Oil & Gas Consulting)

Quadrant 43 North: Regional Seismic Line

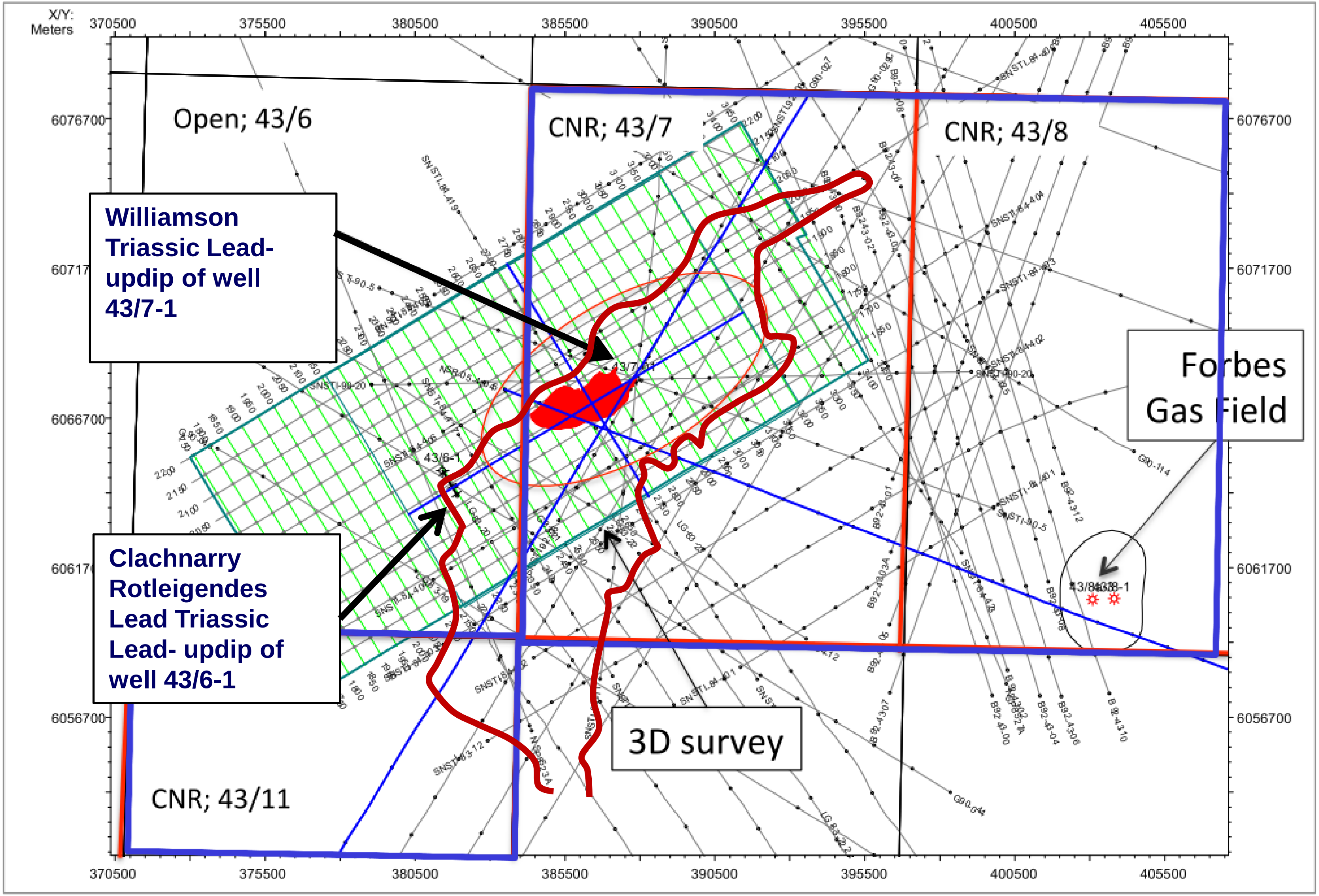




Benign overburden in southern half of line. Prominent linear salt induced diapiric structure and subsided linear prism of preserved Mesozoic sedimentary sequence interpreted along northern margins of Quadrant 43.

Figure 5.4

Block 43/7: Location of Williamson and Clachnaharry Leads



Source: CNR (after P1333 Relinquishment Report, Granby Enterprises)

Figure 5.5

Clachnaharry Lead, 43/7 (Rotliegendes Sandstone Reservoir)

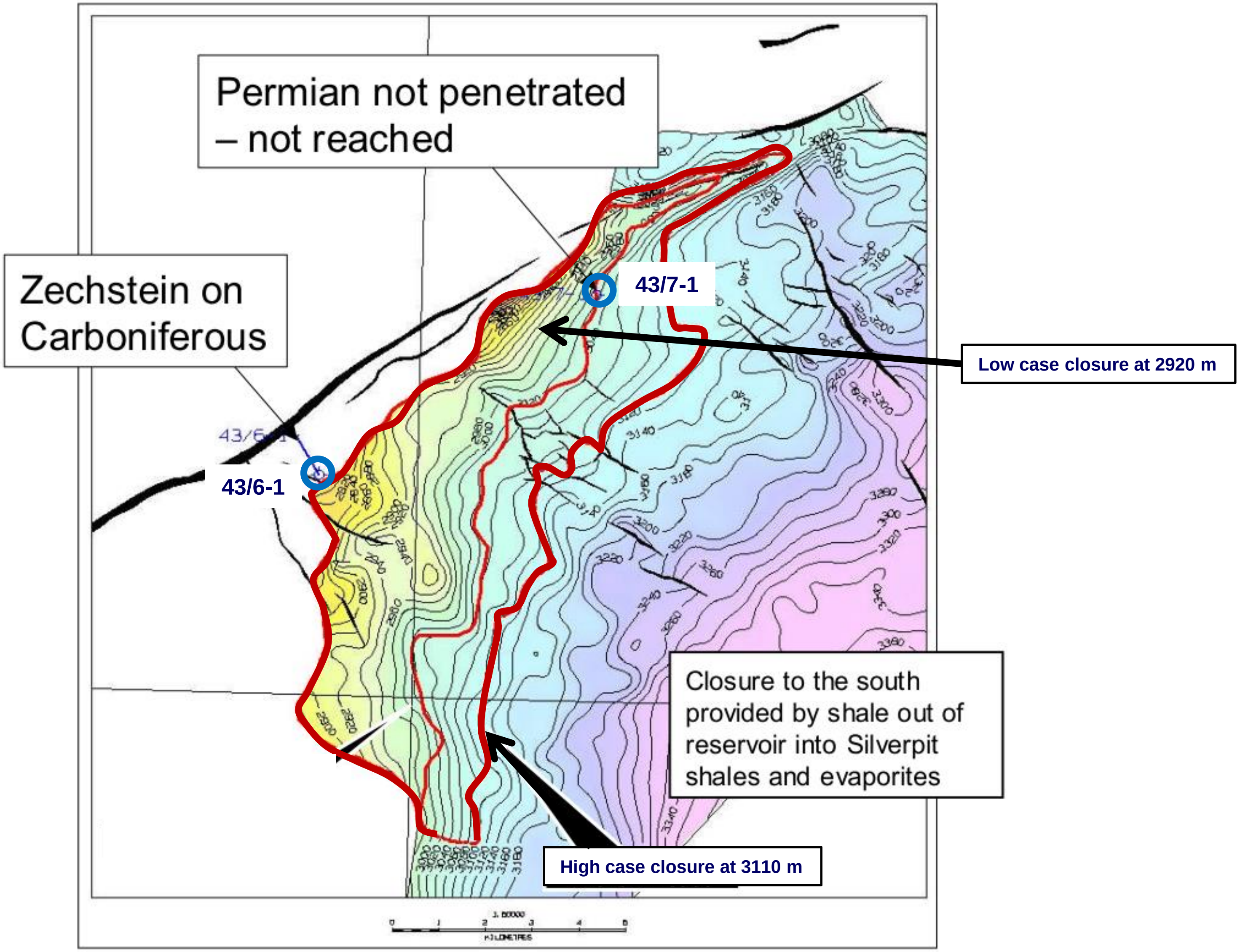


Figure 5.6

Block 43/7: Seismic Line through Clachnaharry & Williamson Leads

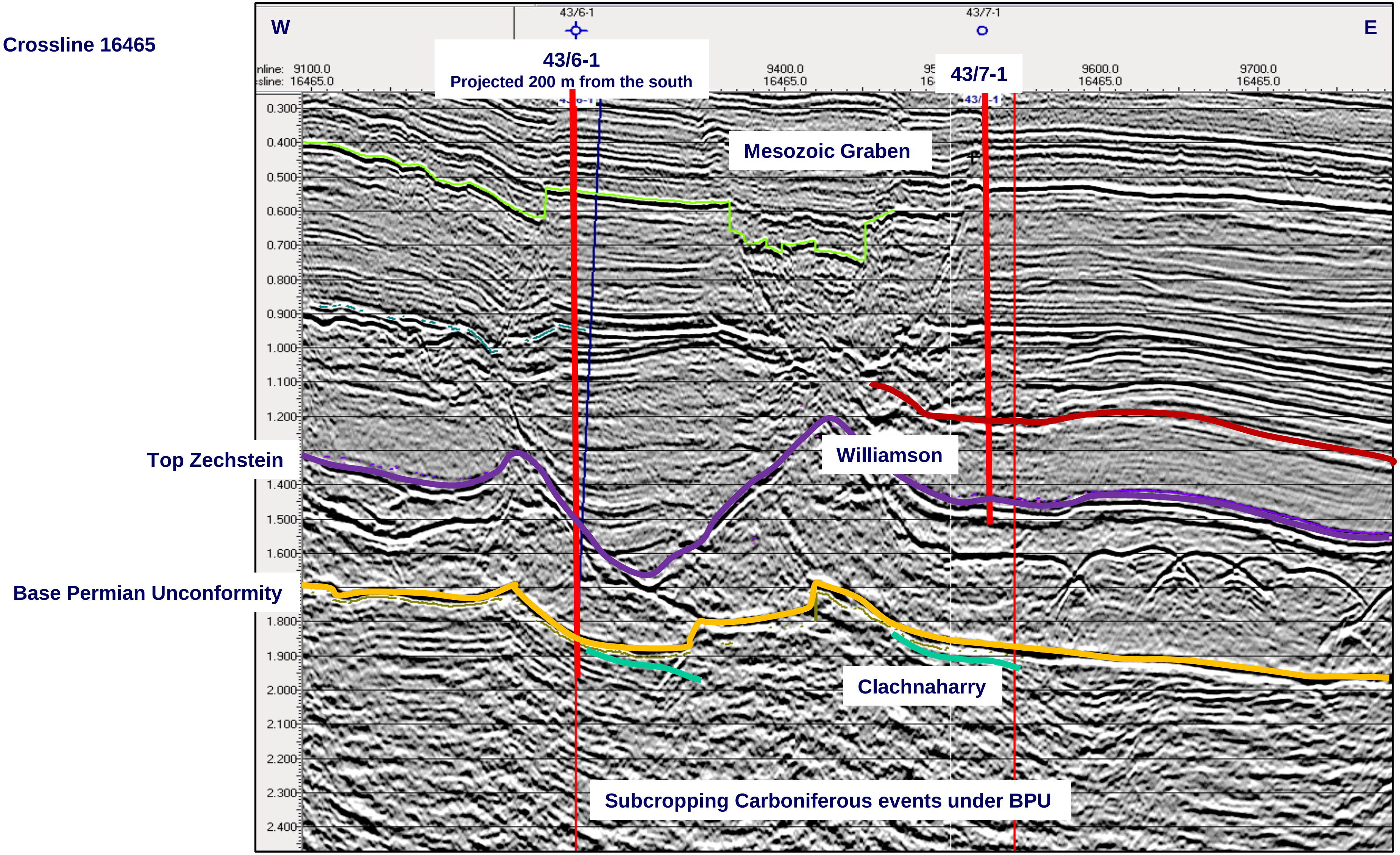


Figure 5.7

Source: CNR Kingdom Project

Williamson Lead, 43/7 (Bunter Sandstone Reservoir)

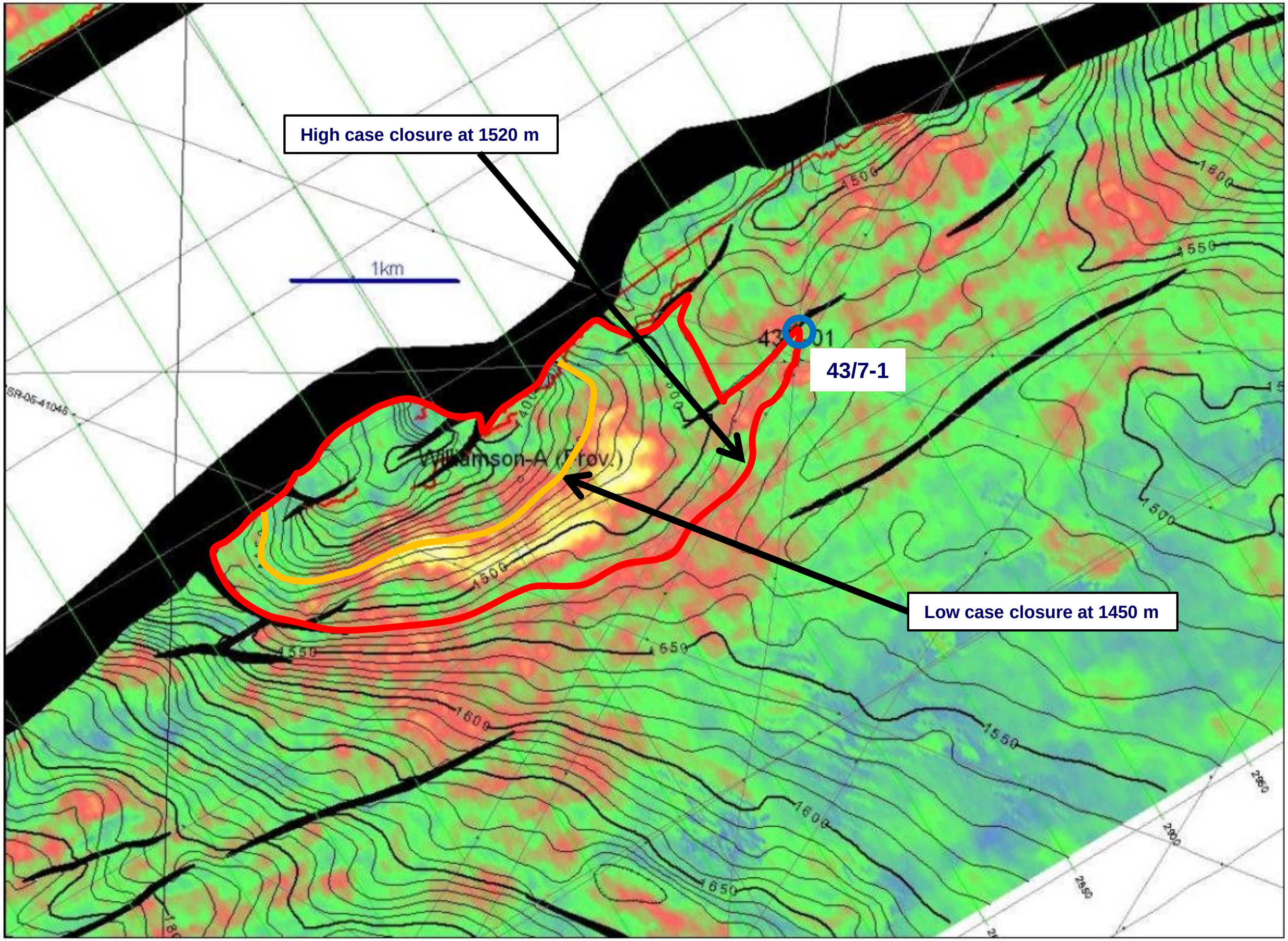


Figure 5.8

Source: P1333 Relinquishment Report, Granby Enterprises

Williamson Lead, 43/7, Seismic Line

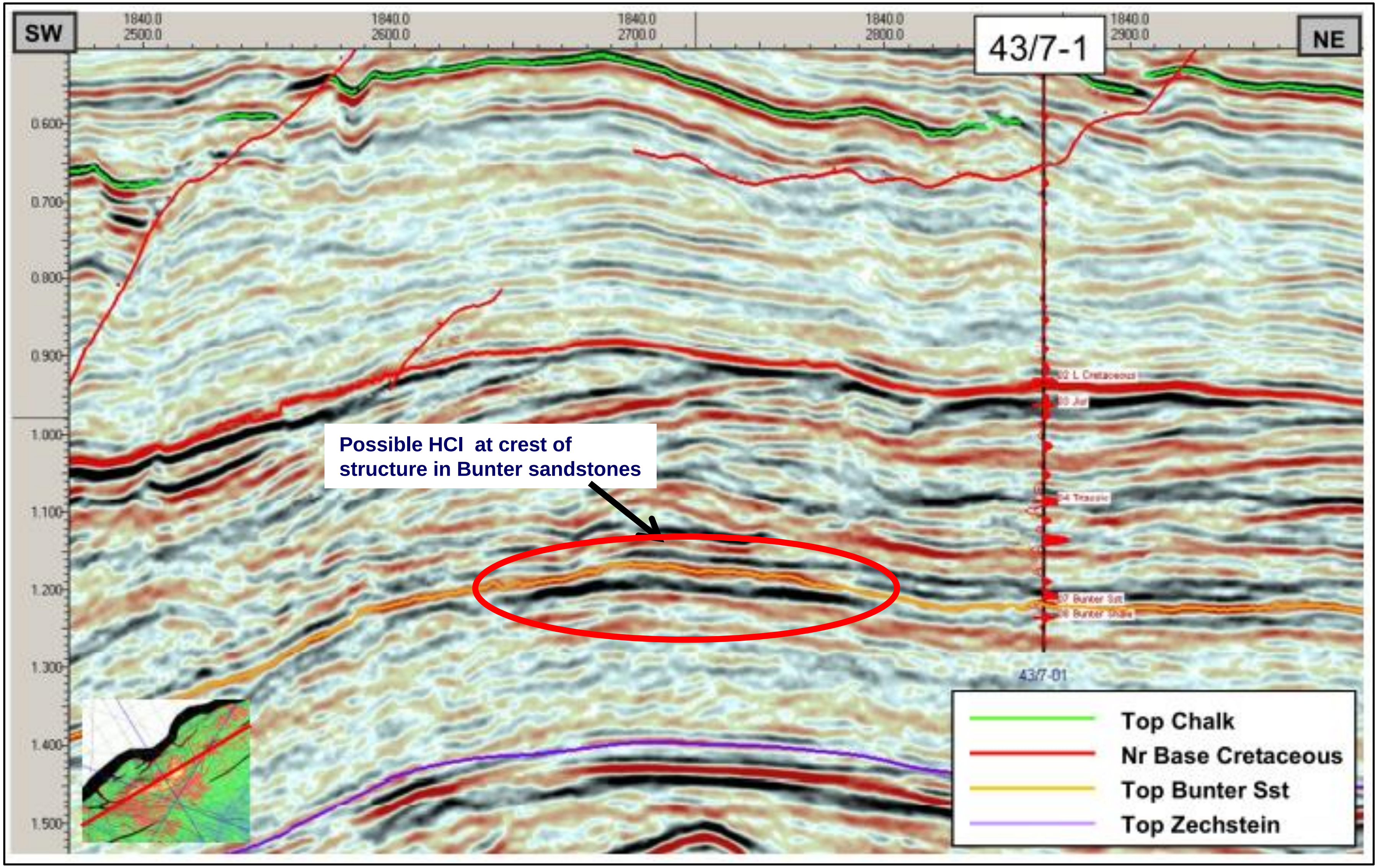
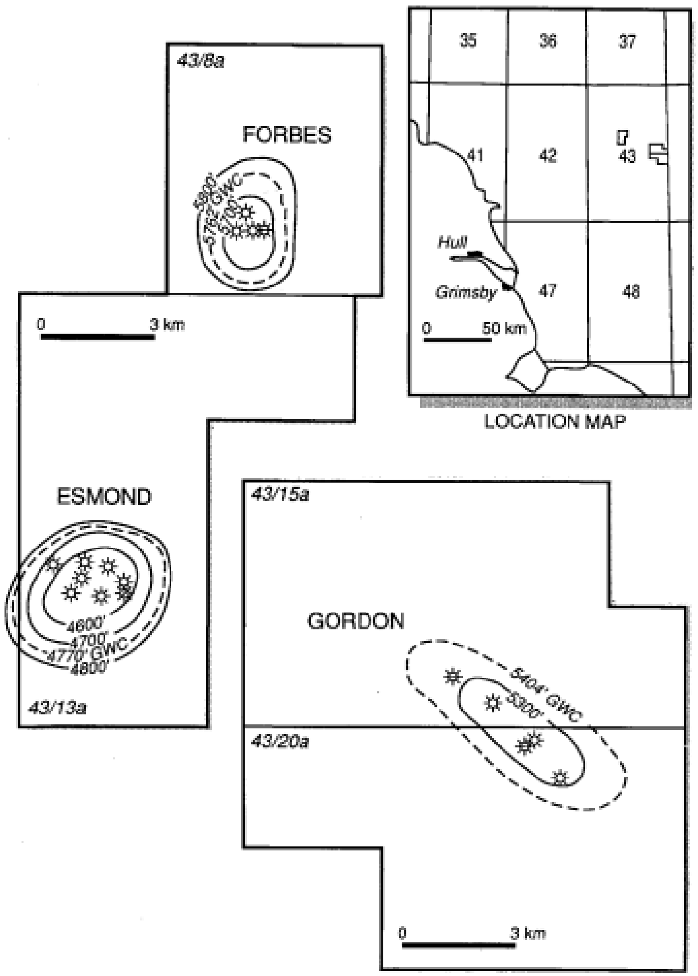


Figure 5.9

Triassic Fields in Northern Sector of Quadrant 43



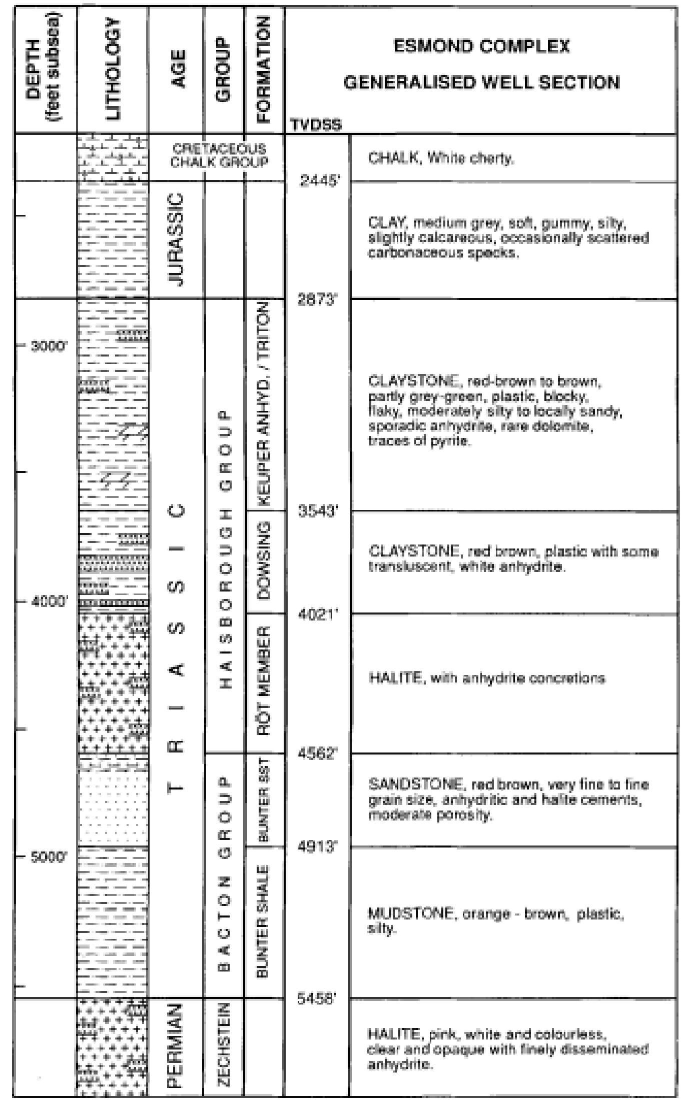
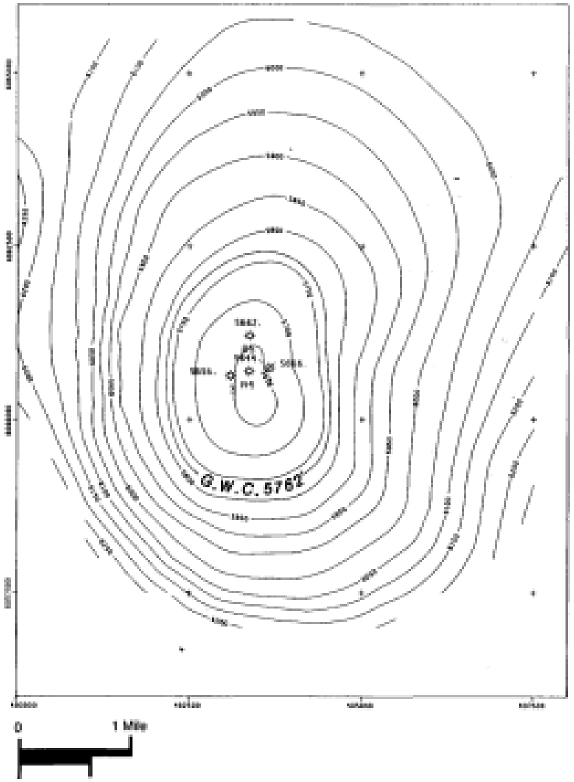


Figure 5.10

Source: Ketter 1991

Forbes Field, 43/8 (Triassic Bunter Sandstone Reservoir)



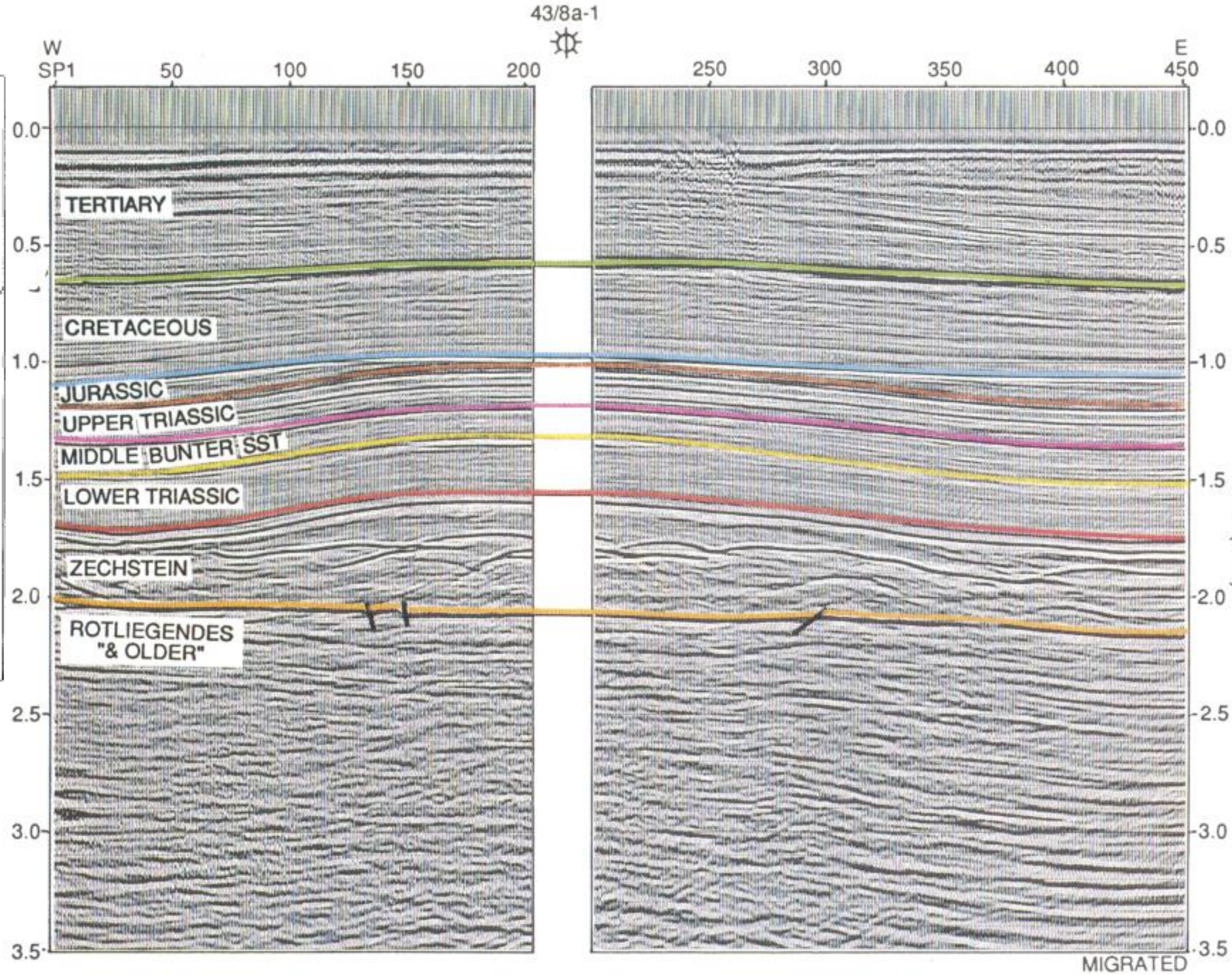


Figure 5.11

Source: Ketter 1991