P2478 LICENCE TECHNICALLY RECOVERABLE RESOURCES, MORAY FIRTH, UKCS

COMPETENT PERSON'S REPORT

Reabold Resources PLC

ECV2491
Reabold Resources -
Competent Person's Report
P2478
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13th February, 2023

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EVALUATION OF ASSET RESOURCES

In response to a request by Reabold Resources PLC ("Reabold"), as operator of the P2478 Joint Venture Group, and the Letter of Engagement dated 26th October 2022 with Reabold (the "Agreement"), RPS Energy Consultants Ltd ("RPS") has undertaken an audit of a number of licences in the UK. This report is an excerpt of the CPR Report, for the use by the Company and Third Parties Baron Oil PLC and Upland Resources (UK Onshore) Limited, concerning the following prospects in Licence P2478:

- Dunrobin West Prospect
- Dunrobin Central and East Prospect
- Golspie Prospect

This report is issued by RPS under the appointment by Reabold and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

We have estimated Low, Best and High case Prospective Technically Recoverable Resources as of 30th September 2022. All Resources definitions and estimates shown in this report are based on the PRMS and reported to the AIM regulations. The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Reabold. Our approach has been to audit the seismic interpretations provided by the client; re-evaluate the petrophysical interpretations of key wells and audit/revise the client's volumetric estimates and risking. Economic evaluation has not been performed.

In estimating Resources, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of in-place and technically recoverable volumes.

We have taken the working interest that Reabold has in the Assets as presented by Reabold. We have not investigated, nor do we make any warranty as to Reabold interest in the Assets.

A site visit was not conducted.

Technically Recoverable Prospective Resources and corresponding geological probability of success (Pg) as of 30th September 2022 are summarised in Section 1.3.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor Director, Consulting has supervised this evaluation. Mr Taylor is a Chartered Engineer and Chartered Geologist with over 40 years' experience in upstream oil and gas. The project has been managed by Ms Eleanor Rollett who has over 25 years of experience in upstream oil and gas and is a Chartered Geologist. Other RPS employees involved in this work hold at least a Master's degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Resources are based on data provided by Reabold. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Reabold, Baron and Upland and their corporate advisors on a fee basis.

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Yours sincerely,
for RPS Energy Consultants Ltd

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Contents

Figures

Tables

Appendices

1 EXECUTIVE SUMMARY

In response to a request by Reabold Resources PLC ("Reabold"), as operator of the P2478 Joint Venture Group, and the Letter of Engagement dated 26th October 2022 with Reabold (the "Agreement"), RPS Energy Consulting Ltd ("RPS") has undertaken an audit of a number of licences in the UK. This report is an excerpt of the CPR Report, for the use by the Company and Third Parties Baron Oil PLC and Upland Resources (UK Onshore) Limited, concerning the following prospects in Licence P2478:

- Dunrobin West Prospect
- Dunrobin Central and East Prospect
- Golspie Prospect

This report is issued by RPS under the appointment by Reabold and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

1.1 Overview of Dunrobin and Golspie Propects

The Dunrobin and Golspie prospects are located in the P2478 licence, containing Blocks 12/27c; 17/5; 18/1 and 18/2. The licence is operated by Reabold Resources North Sea Limited along with joint venture partners Baron Oil PLC (32%) and Upland Resources (Onshore UK) Limited (32%).

1.2 Surface Review

Dunrobin is an undrilled group of oil prospects in the UK North Sea. If a discovery is made Reabold proposes to use a leased FPSO with subsea wells as the development concept for Dunrobin West. The associated gas would be used for fuel with excess re-injected into the reservoir. In potential upside cases gas export to the nearby Captain Field may be economically viable. Subsea production wells will be fitted with downhole ESPs routed to a redeployed existing FPSO.

RPS is supportive of the concept presented by Reabold.

However, the crude expected in Dunrobin is potentially partially degraded due to low reservoir depth and may be of low API or waxy. Similar crudes have been developed in the UK North Sea, but flow assurance issues may arise which may require more costly facilities than have been assumed by Reabold.

Golspie is an undrilled Jurassic oil prospect to the west of the Dunrobin prospects. If exploration well on Golspie is successful, Reabold has considered a development consisting of subsea wells tied to a leased redeployed FPSO similar to that assumed for Dunrobin. Due to the similarity with the concept presented for Dunrobin, RPS is supportive of the concept for Golspie.

In the event of exploration and appraisal success at Dunrobin, Dunrobin West and Golspie, a joint development may be the optimal solution, but this has not been considered further at this time by RPS.

1.3 Subsurface and Resource Evaluation

RPS has reviewed the subsurface data provided by Reabold. Additionally, RPS has independently generated CPIs for two wells: 12/27-1 and 12/26c-5, at the request of the client. In additional RPS has performed fluid substitution on these wells to assist Reabold in evaluating the seismic response to reservoir fluids. RPS has reviewed the seismic interpretation and depth conversion provided and consider them to be appropriate. RPS has used MonteCarlo simulation within Logicom's REP software to establish a range of in-place volumes; these are summarised in Table 1-1 and Table 1-2.

RPS has reviewed the likely fluid properties based on offset and analogue data and defined a range of appropriate recovery factors. The range of recovery factors have been combined stochastically with the in-place volumes to generate technically recoverable resources. These are quoted in Table 1-3 and Table 1-4 along with the associated Geological Probability of Success (Pg).

	STOIIP (MMstb)			
	Low	Best	High	Mean
Dunrobin West				
Jurassic	31	194	735	313
Triassic	33	157	423	201
Dunrobin Central and East				
Jurassic	6	34	299	98
Triassic	5	43	247	98
Golspie				
Jurassic	14	47	95	52
Triassic	28	74	150	83

Table 1-1: Gross STOIIP for All Assets

	GIIP (Bscf)			
	Low	Best	High	Mean
Dunrobin West				
Jurassic	3	5	8	5

Table 1-2: Gross GIIP for All Assets

SUMMARY OF OIL PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES
As of 30th September 2022[6]

	Gross Prospective Resources (Unrisked)[1,4] (MMstb)				Reabold Net Prospective Resources (Unrisked)[2, 3, 4] (MMstb)				Pg (%)
	1U	2U	3U	Mean[5]	1U	2U	3U	Mean[5]	
Dunrobin West									
Jurassic	7	42	168	71	2	15	60	25	34
Triassic	7	34	98	45	2	12	35	16	12
Dunrobin Central and East									
Jurassic	1	8	67	22	0.4	3	24	8	31
Triassic	1	9	56	22	0.4	3	20	8	14
Golspie									
Jurassic	4	12	27	14	1	4	10	5	27
Triassic	7	20	43	23	3	7	15	8	12

Notes:

*1.Gross field Resources (100% basis) **before** economic limit test*

*2 Companies working interest share of net field Resources **before** economic limit test*

3. Reabold net working interest is 36%

*4. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

5. Mean is defined as the arithmetic average of successful outcomes

6. Aligned with effective date of primary CPR.

Table 1-3: Oil Prospective Technically Recoverable Resources as of 30th September 2022

SUMMARY OF OIL PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES As of 30th September 2022[5]									
	Upland Resources Net Prospective Resources (Unrisked)[1, 2, 3,] (MMstb)				Baron Oil Net Prospective Resources (Unrisked)[1, 2, 3,] (MMstb)				Pg (%)
	1U	2U	3U	Mean[4]	1U	2U	3U	Mean[4]	
Dunrobin West									
Jurassic	2	13	54	23	2	13	54	23	34
Triassic	2	11	31	15	2	11	31	15	12
Dunrobin Central and East									
Jurassic	0.4	2	21	7	0.4	2	21	7	31
Triassic	0.3	3	18	7	0.3	3	18	7	14
Golspie									
Jurassic	1	4	9	5	1	4	9	5	27
Triassic	2	6	14	7	2	6	14	7	12

Notes:

*1 Companies working interest share of net field Resources **before** economic limit test*

2. Upland Resources and Baron Oil net working interest is 32%

*3. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

4. Mean is defined as the arithmetic average of successful outcomes

5. Aligned with effective date of primary CPR.

Table 1-4: Oil Prospective Technically Recoverable Resources as of 30th September 2022 – JV Partners

SUMMARY OF GAS PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES
As of 30th September 2022[7]

	Gross Prospective Resources (Unrisked)[1,5] (Bscf)				Reabold Net Prospective Resources (Unrisked)[3, 4, 5] (Bscf)				Pg (%)
	1U	2U	3U	Mean[6]	1U	2U	3U	Mean[6]	
Dunrobin West									
Jurassic[2]	2	7	22	10	0.9	3	8	4	34
Triassic	1	4	11	5	0.3	1	4	2	12
Dunrobin Central and East									
Jurassic	0.1	1	7	2	0.04	0.3	3	1	31
Triassic	0.1	1	6	2	0.04	0.4	2	1	14
Golspie									
Jurassic	0.4	1	3	2	0.1	0.5	1.1	0.6	27
Triassic	0.8	2	5	3	0.3	0.8	1.7	1.0	12

Notes:

1.Gross field Resources (100% basis) ***before*** *economic limit test*

2.Includes a mix of associated gas and non-associated gas from Dunrobin West Gas Cap, all others are associated gas ***only***

3.Companies working interest share of net field Resources ***before*** *economic limit test*

4.Reabold net working interest is 36%

5. The volumes are presented for each reservoir and, at the client request, have ***not*** *been aggregated.*

6. Mean is defined as the arithmetic average of successful outcomes

7. Aligned with effective date of primary CPR

Table 1-5: Gas Prospective Technically Recoverable Resources as of 30th September 2022

SUMMARY OF GAS PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES As of 30th September 2022[5]	Upland Resources Net Prospective Resources (Unrisked)[2, 3, 4] (Bscf)				Baron Oil Net Prospective Resources (Unrisked)[2, 3, 4] (Bscf)				Pg (%)
	1U	2U	3U	Mean[5]	1U	2U	3U	Mean[5]	
Dunrobin West									
Jurassic[1]	0.8	2	7	3	0.8	2	7	3	34
Triassic	0.2	1	3	2	0.2	1	3	2	12
Dunrobin Central and East									
Jurassic	0.04	0.3	2	1	0.04	0.3	2	1	31
Triassic	0.03	0.3	2	1	0.03	0.3	2	1	14
Golspie									
Jurassic	0.1	0.4	1.0	0.5	0.1	0.4	1.0	0.5	27
Triassic	0.3	0.7	1.5	0.9	0.3	0.7	1.5	0.9	12

Notes:

*1.Includes a mix of associated gas and non-associated gas from Dunrobin West Gas Cap, all others are associated gas **only***

*2.Companies working interest share of net field Resources **before** economic limit test*

3. Upland Resources and Baron Oil net working interest is 32%

*4. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

5. Mean is defined as the arithmetic average of successful outcomes

6. Aligned with effective date of primary CPR

Table 1-6: Gas Prospective Technically Recoverable Resources as of 30th September 2022 – JV Partners

1.4 Economic Analysis

Economic analysis has not been performed for these resources.

2 INTRODUCTION

In response to a request by Reabold Resources PLC ("Reabold"), as operator of the P2478 Joint Venture Group, and the Letter of Engagement dated 26th October 2022 with Reabold (the "Agreement"), RPS Energy Consulting Ltd ("RPS") has undertaken an audit of a number of licences in the UK. This report is an excerpt of the CPR Report, for the use by the Company and Third Parties Baron Oil PLC and Upland Resources (UK Onshore) Limited, concerning the following prospects in Licence P2478:

- Dunrobin West Prospect
- Dunrobin Central and East Prospect
- Golspie Prospect

This report is issued by RPS under the appointment by Reabold and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. The purpose of this CPR is for general investor marketing purposes and to facilitate a farm-out process.

We have estimated Prospective Technically Recoverable Resources as of 30th September 2022. The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Reabold. Our approach has been to audit the Operator's own estimates of Prospective Resources based on the 2018 SPE Reserves Auditing Standards and the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System (PRMS) 2018.

Reabold Resources is a UK based exploration and development company, with a portfolio consisting of offshore prospects in the UK North Sea and onshore prospects and developing assets in the UK North Sea, Romania and the US.

Reabold Resources has built a portfolio of prospects and developing assets through a series of acquisitions. This report is on the prospects in the UK North Sea licence P2478, for which Reabold's working interest was acquired, as part of a portfolio of assets, from Corallian in September 2022 (Figure 2.1). The licence status is summarised in Table 2-1. Reabold is currently in Phase A of the licence a four-year term which commenced in July 2019. The prospects are being assessed for drilling as there is a drill-or-drop decision to be made by the end of Phase A in July 2023.

Figure 2.1: Reabold North Sea Portfolio in the UK North Sea[1]

Asset	Country	Licence	Operator	Client Working Interest	Development Status	Licence Expiry Date	Partners
Dunrobin & Golspie Prospects	United Kingdom	P2478	Reabold Resources Plc (36%)	36%	Phase A	July 2023	Baron Oil (32%) Upland Resources (32%)

Table 2-1: Summary of Reabold P2478 Licence Status

[1] *Reabold Resources plc Website - https://reabold.com/projects/corallian/*

3 BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Resources are based on data provided by Reabold. We have accepted, without independent verification, the accuracy of the data and Reabold have confirmed in their letter of representation that the data are complete.

The report represents RPS' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

This report is issued by RPS under the appointment by Reabold and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

3.1 Audit Methodology

As noted above, our approach has been to audit Reabold's estimates of recoverable volumes, based on the 2019 SPE Reserves Auditing Standards, which describe an audit as follows:

A reserves audit is the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or reserves information prepared by others and the rendering of an opinion about:

1. *the appropriateness of the methodologies employed,*
2. *the adequacy and quality of the data relied upon,*
3. *the depth and thoroughness of the reserves estimation process,*
4. *the classification of reserves appropriate to the relevant definitions used, and*
5. *the reasonableness of the estimated reserves quantities and/or the Reserves Information.*

The term "reasonableness" cannot be defined with precision but should reflect a quantity and/or value difference of not more than plus or minus 10%, or the subject reserves information does not meet minimum recommended audit standards.

This tolerance can be applied to any level of reserves or reserves information aggregation, depending upon the nature of the assignment, but is most often limited to proved reserves information. A separate predetermined and disclosed tolerance may be appropriate for other reserves classifications. Often a reserves audit includes a detailed review of certain critical assumptions and independent assessments with acceptance of other information less critical to the reserves estimation. Typically, a reserves audit letter or report is prepared, clearly stating the assumptions made. A reserves audit should be of sufficient rigor to determine the appropriate reserves classification for all reserves in the property set evaluated and to clearly state the reserves classification system being utilised. In contrast to the term "audit" as used in a financial sense, a reserves audit is generally less rigorous than a reserves report.

4 SITE VISIT

No site visit has been undertaken by RPS as it was not in the scope of work of this report.

5 P2478

5.1 Introduction

The Dunrobin and Golspie prospects are located in the P2478 licence, containing Blocks 12/27c; 17/5; 18/1 and 18/2 (Figure 5.1). The licence is operated by Reabold Resources and joint venture partners are Baron Oil (32%) and Upland Resources (32%). If a discovery is made, Reabold proposes to use a leased FPSO with subsea wells as the development concept for potential future discoveries in this licence.

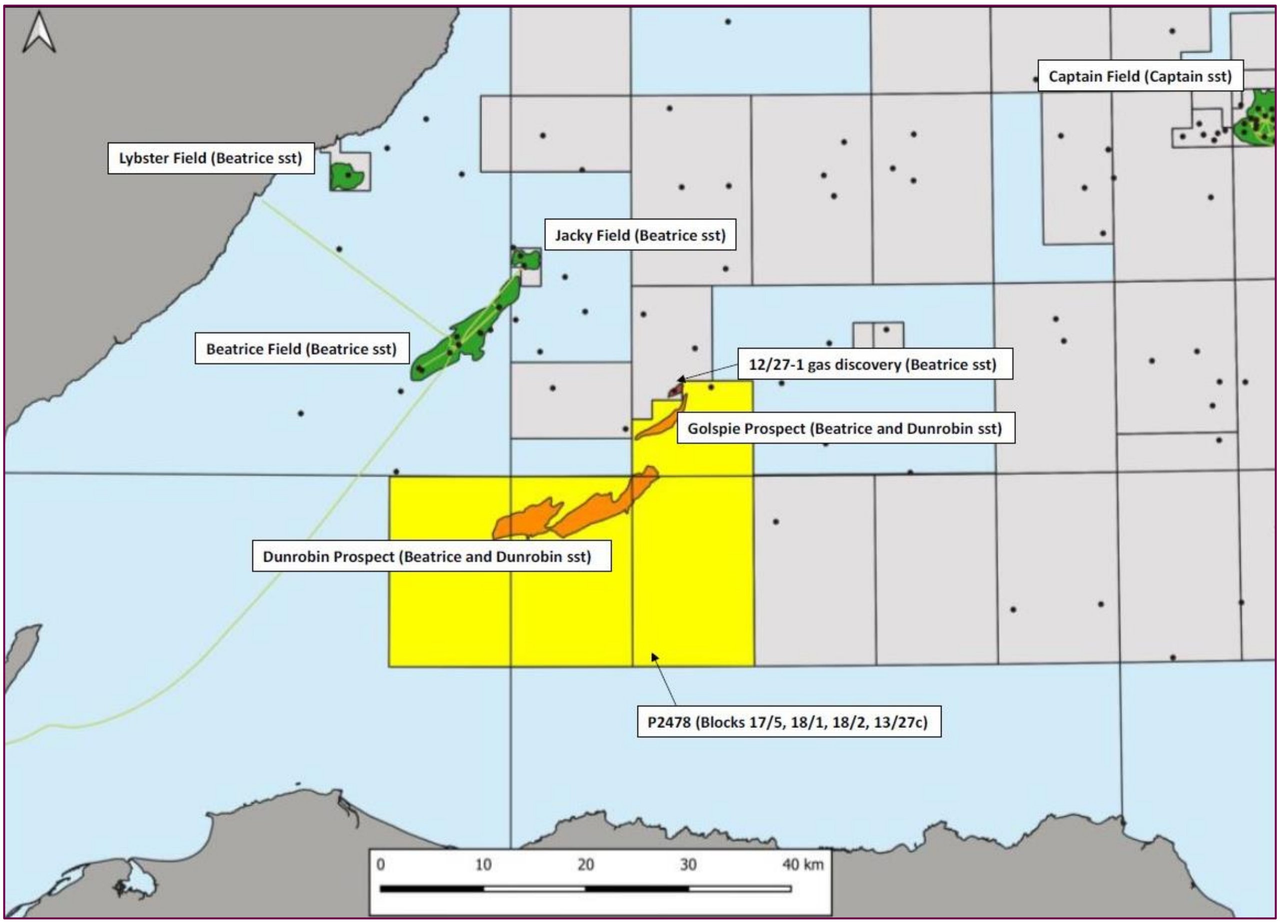

Figure 5.1: Licence Location Map[2]

A summary of nearby exploration and appraisal wells that have been used for the evaluation of the P2478 licence can be found in Table 5-1.

[2] *Provided by Reabold Resources – Offshore U.K. Portfolio Presentation. October 2022*

	Well Name	Status	Year	Notes
Exploration/ Appraisal Wells	11/30-6	P&A	1978	Britoil. 141m Beatrice / Brora / Dunrobin Bay section. Recovered 21.5 litres of 35.7oAPI oil from Brora Coal Fm sand at -1,345m TVDSS. Renamed Sybil discovery by Ithaca
	12/27-1	P&A	1982	Burmah. 50m Beatrice / DunrobinBay sands. Tested 10mmscfg/d from 14m of Beatrice Fm. Oil recovered from Jurassic core
	12/27-2	P&A	1983	Burmah. 98m Beatrice / Dunrobin Bay sands. Oil stains in topmost section.
	12/27a-3	P&A	1990	Premier. Basinal well with Lower Cretaceous & Upper Jurassic deepwater sands, with oil and gas shows.
	12/27-4	P&A	2015	Suncor. Basinal well targeting intra-Kimmeridge sand ("Niobe"). No shows.
	18/3-1	P&A	1992	Arco. 54m Beatrice / Dunrobin Bay sands. Good quality Triassic sands. Upper Jurassic & Lower Cretaceous sections dominated by mudrocks.
	12/26-1	P&A	1967	Hamilton Bros. 86m Beatrice / Dunrobin Bay section containing high quality, water-wet sands.
	11/29-1	P&A	2008	Ithaca. Beatrice & Brora Coal Fm. Thin and tight sands with residual oil but no pay.

Table 5-1: P2478 Wells

5.2 Data

Reabold supplied the following data for the P2478 licence:

- Full stack re-processed seismic 3D seismic in the time domain.
- 18 re-processed 2D seismic lines in the time domain.
- Seismic interpretation (grids, fault polygons, TWT grids, depth grids, volumetric polygons).
- Velocity model.
- Digital well data for 12/26-1, 11/30-6, 12/27-1,12/27-2, 12/26c-5 including:
  - Time Depth tables
  - Raw logs (las.)
  - Location, headers and deviation
  - Various reports.

5.3 Subsurface Evaluation

5.3.1 Geological Setting

Licence P2478 is located in the Inner Moray Firth Basin and comprises the Dunrobin West, Dunrobin Central and East and Golspie prospects in Blocks 12/27c; 17/5; 18/1; 18/2. The licence was awarded to Corallian and its partners in the 31st UKCS Licensing Round in 2019. Reabold's working interest was acquired, as part of a portfolio of assets, from Corallian in September 2022.The prospects lie updip from the nearby Beatrice Field and consist of several rotated fault blocks. Figure 5.3 shows the location of the prospects highlighted on a depth map of the top reservoir in the P2478 licence.

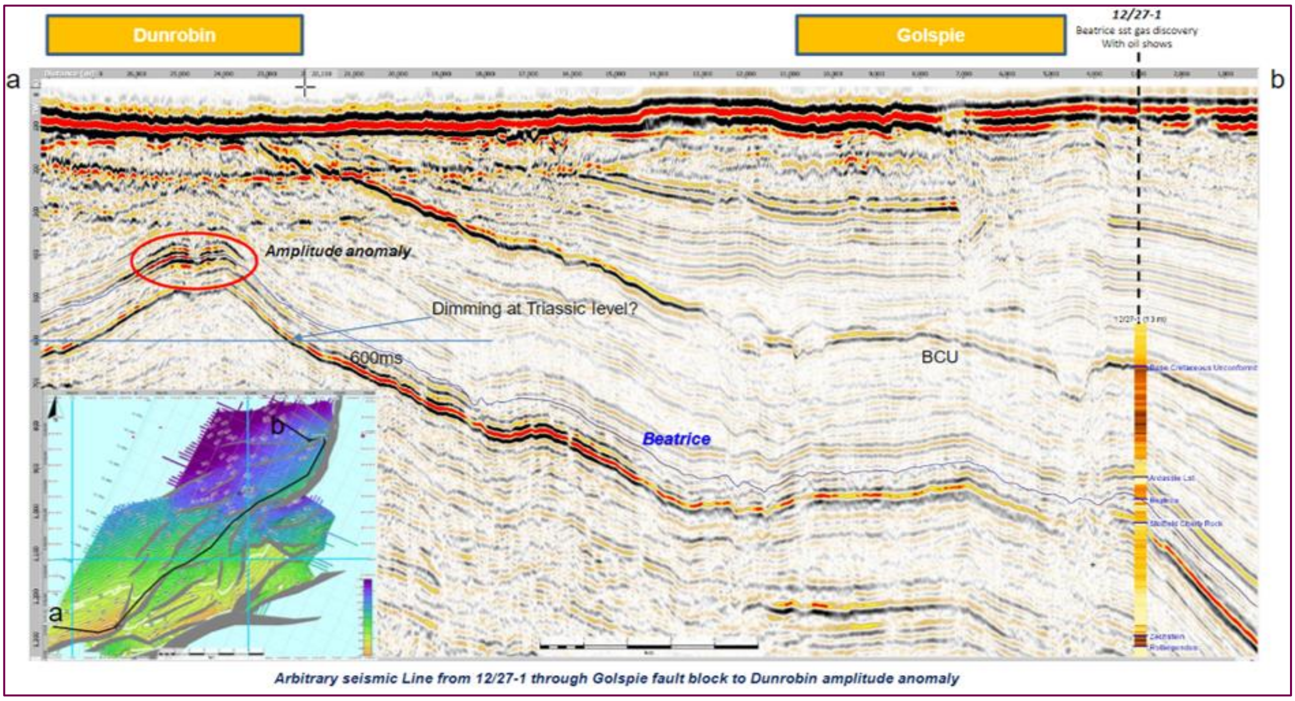

Figure 5.2: Representative Seismic Line Through P2478 Extending from Dunrobin West to Golspie[3]

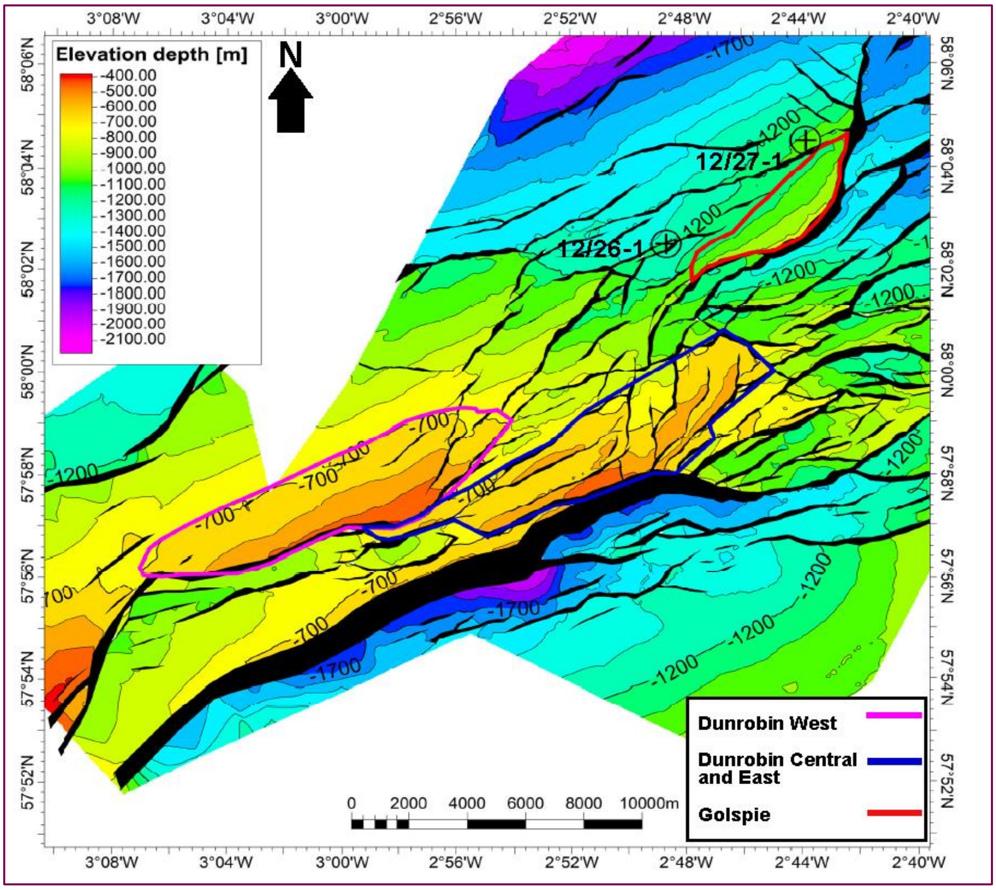

Figure 5.3: Prospects Location Map – Top Beatrice Depth (mTVDSS)

[3] *Reabold Resources – Offshore UK Portfolio Presentation*

The reservoir targets are the Beatrice and Dunrobin Bay sandstones (Jurassic), with additional upside in the underlying Triassic Lossiehead Formation. A stratigraphic chart is shown in Figure 5.4 highlighting the regional stratigraphy.

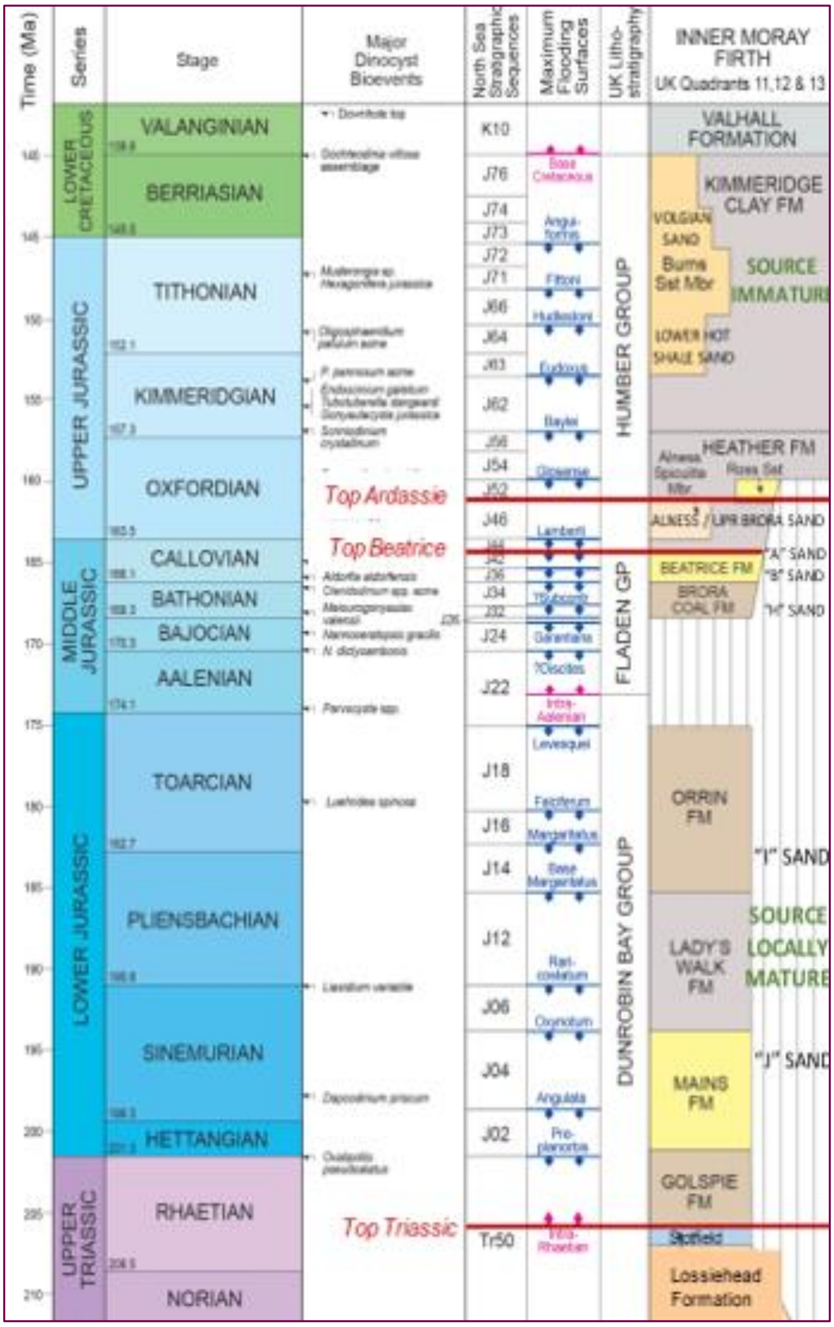

Figure 5.4: Stratigraphic Column for the Prospects in the P2478 Licence[4]

The Beatrice Formation is interpreted to have formed in a shallow marine/shoreface environment and directly overlies the Brora Coal Formation. The primary reservoir targets in the Beatrice Formation are the A & B sands which individually vary from 10-40m thick in the vicinity of P2478. Wells to the southwest of the P2478 licence highlight a transition from generally higher net sand, upper shoreface facies to a lower net sand, lower shoreface/transitional facies within the Beatrice Formation, as shown in Figure 5.5, resulting in a general reduction in reservoir quality and thickness to the southwest (highlighted by the 11/29-1 well drilled by Ithaca). The Dunrobin Bay Group is interpreted to be a fluvio-deltaic/shoreface facies and is principally lower Jurassic, lying stratigraphically below the Brora Coal Formation, and containing the Orrin and Mains

[4] *Reabold Resources TCM, 3rd October 2022*

formations. Targets within the Dunrobin Bay Group are locally referred to as the I and J sands and range from 20-50m in thickness locally, with the Orrin Formation generally showing the thicker more developed sands. Finally, the Triassic Lossiehead Formation represents a deeper, locally unproven, reservoir target, comprising a thick (>200m) series of interbedded massive sands and evaporites in the Upper Triassic. These sands are separated from the overlying Dunrobin Bay Group by the Stotfield Chert Member which forms a regional marker across the licence and on the 2D and 3D seismic (Figure 5.6).

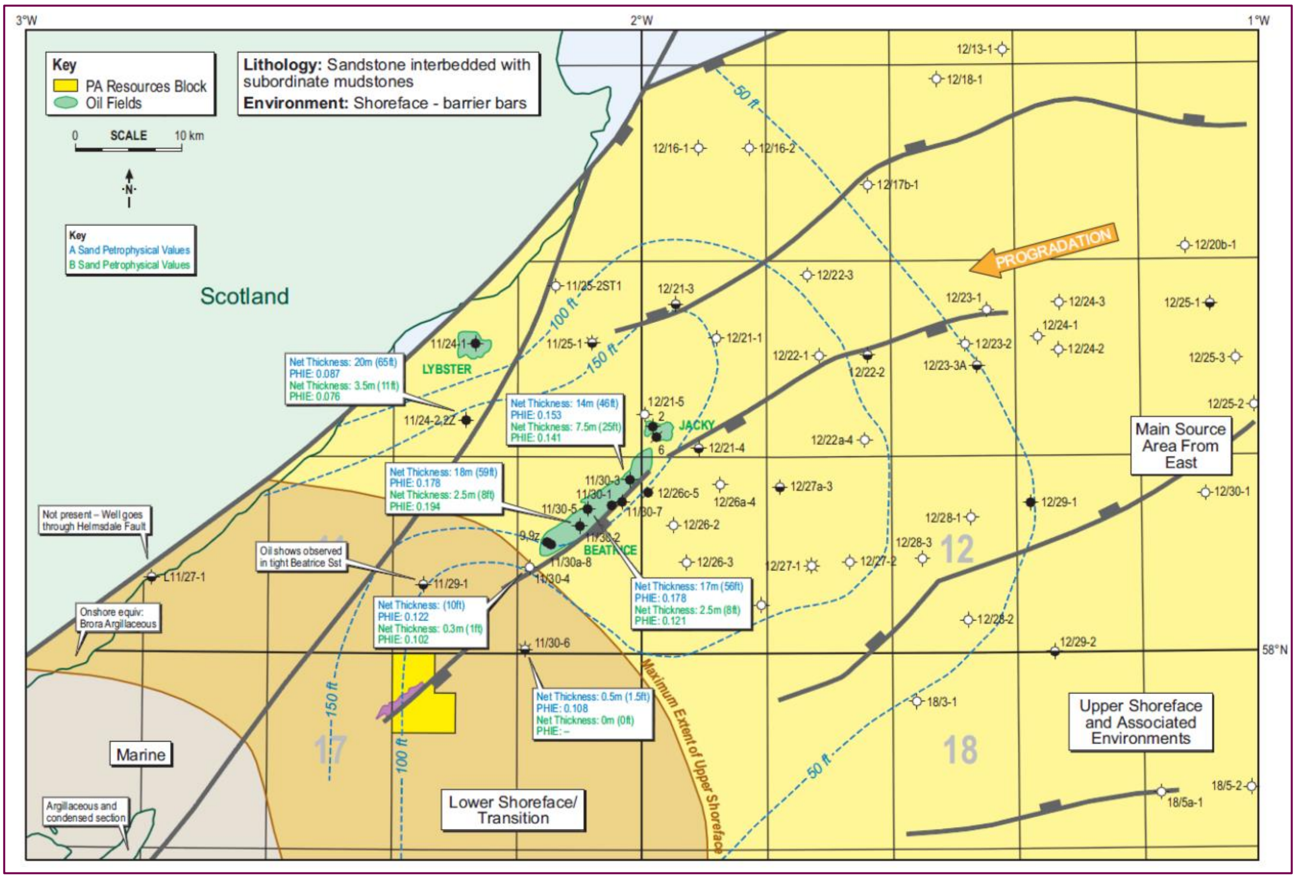

Figure 5.5: Beatrice Paleogeographic Map Demonstrating Maximum Extent of Upper Shoreface Facies[5]

[5] *Modified after PA Resources, P1342 relinquishment report, 2013*

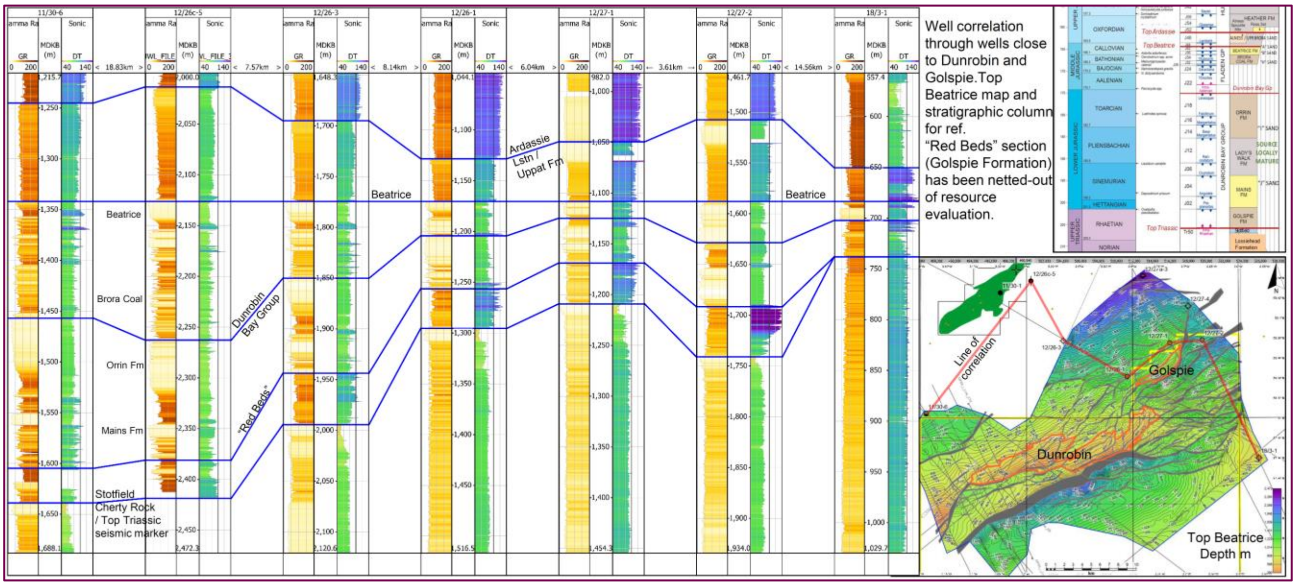

Figure 5.6: Regional Well Correlation in the vicinity of P2478[6]

There are three potential source rocks in P2478. Firstly, the Struie Formation (Devonian) which is a lacustrine shale. This is the most likely source for the mapped prospects and has been proven at the Beatrice Field approximately 20km northwest of the prospects in P2478. Local well 12/27-1 recovered hydrocarbons which were typed to a Devonian source rock, identical to the oils in the Beatrice field. The recovered oils in 12/27-1 and Beatrice are interpreted to be from an oil prone, waxy paraffinic kerogen (typical of the Devonian) and it would be expected that any recoverable hydrocarbons from the prospects in P2478 to have similar characteristics. Additionally, the Lady's Walk Formation (Pliensbachian/Sinemurian) and the Kimmeridge Clay Formation are alternative source formations. However, locally these are immature due to insufficient burial depths.

The Devonian source rock is modelled to have had two main phases of oil generation: an early phase in the late Carboniferous and then a main phase from the mid to late Cretaceous to present day (Figure 5.7). Based on measured vitrinite reflectance data from the 12/27-1 well, the Devonian source rocks are in the peak oil generation phase at present day. The main kitchen is expected to lie less than 10km to the north of P2478 beneath the Beatrice field, and off structure from the P2478 prospects.

[6] *P2478 Technical Committee Meeting 3rd October 2022*

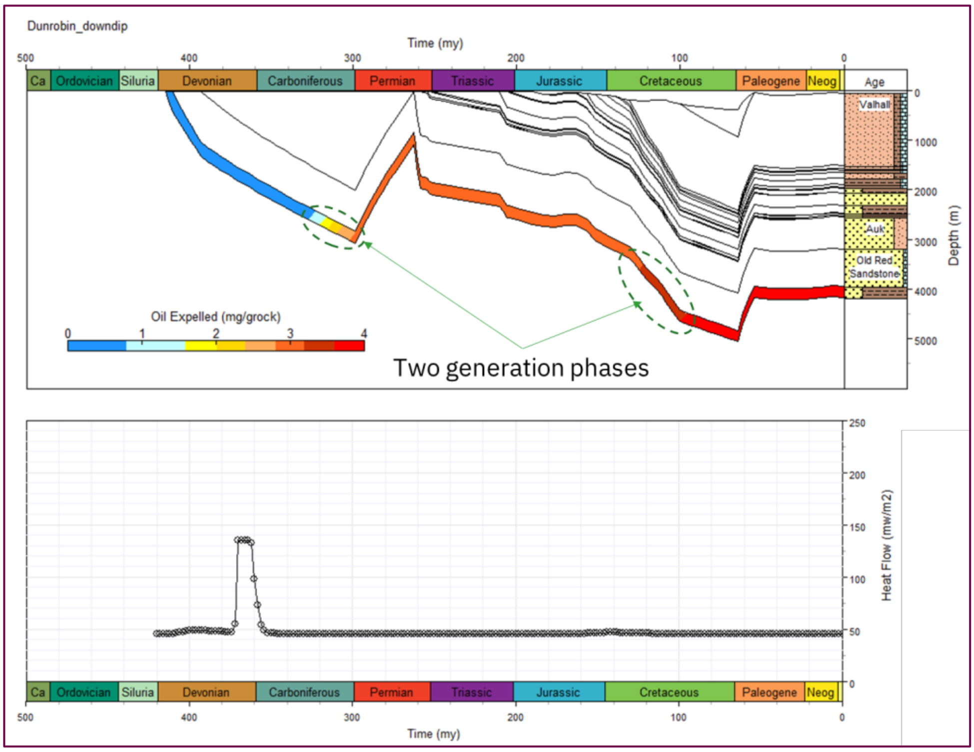

Figure 5.7: 1D Burial History and Generation Plot for the Dunrobin West Prospect[7]

The principle regional seal in P2478 is the Heather formation. This seal is proven at the Beatrice Field which holds a ~250m oil column at 1800 meters TVDSS. Lying stratigraphically above the Heather Formation is the Kimmeridge Clay Formation which also acts as a regional seal. The Heather and Kimmeridge formations are generally accepted to provide good quality lateral and top seals, however, occasional channel sands (e.g. Burns member) can act as 'thief' zones. Such channel sands are more prevalent to the east and northeast and mapping carried out by Reabold and Suncor suggests that these channels do not extend into the P2478 licence (Figure 5.8).

Reabold also propose that the Stotfield Chert Member may act as a local seal for the underlying Triassic reservoir targets, however this is yet to be proven within the basin.

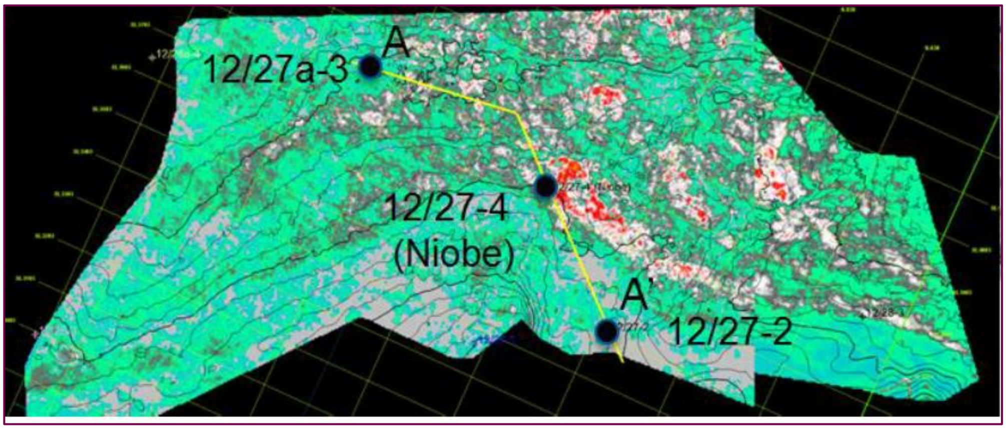

Figure 5.8: Amplitude Map within the Upper Jurassic showing southern limit of Burns channel fairway, relative to the 12/27-2 well[8]

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[7] *Reabold proprietary modelling study conducted in 2022 by APT ltd.*

[8] *Suncor P1889 relinquishment report, 2015*

5.3.2 Petrophysical Evaluation

5.3.2.1 CPI Generation

RPS generated a set of CPIs for wells 12/27-1 and 12/26c-5 as a benchmark for reservoir properties within the hydrocarbon-bearing Beatrice Formation and Dunrobin Bay Group. A first pass approximation of porosity and lithology was also generated from surface to top Beatrice and from base Dunrobin to TD for fluid substitution.

The steps used to generate these CPIs are listed below in sequence order:

- Load logs from supplied LAS files. Add Reabold zone tops and locate interval of interest.
- QC logs across interval of interest. Check logs are on depth and corrected for bad hole using GR-derived log responses across good hole.
- Calculate VSH from GR Log, checking against cuttings lithology on composite logs (note: the LogIC log analysis program used in the log analysis automatically labels this as VCL, but as no distinction is made between clay and silt, it is more accurately described as VSH).
- Calculate PHIT from Density Log, calibrated to core PHIT in 12/27-1 (no core or SWC's acquired in 12/26c-5).
- Calculate PHIE using the equation PHIE=PHIT x (1-VSH).
- SW was calculated using Archie Equation. PHIE was input giving SWE. Additional inputs were:
  - Fm temperature from average Moray Firth geothermal gradient (Figure 5.9).
    - Gives Beatrice-Dunrobin Fm temps of ~37-38C in 12/27-1, and ~71-75C in 12/26c-5.
  - Simple invasion corrected Rt.
    - 12/27-1 drilled with WBM: Where Rdeep>Rshallow, Rt=(1.7.LLD)+(0.7.LLS). Where Rdeep<=Rshallow, Rt=(2.4.LLD)+(1.4.LLS).
    - 12/26c-5 drilled with OBM: Where Rdeep>Rshallow*, Rt=(1.7.LLD)+(0.7.LLS). Where Rdeep=<Rshallow, Rt=Rdeep.
  - Rw, a, m, n from Pickett plots (Figure 5.10).
    - a=1, m=n=2.
    - Dunrobin water: 12/26c-5 Rw 0.04ohmm at 75C, 79kppm NaCl equiv. 12/27-1 Rw 0.83ohm at 38, 5kppm NaCl equiv.
- Permeability (kah) was calculated from log PHIE vs core kah in 12/27-1 (Figure 5.11).
- Cutoffs:
  - Beatrice Fm & Dunrobin Bay Gp: **NET** where VSH<0.5 fr (corresponds with top/base Beatrice Fm, top/base Dunrobin Bay Gp, and excludes obvious shale breaks within them).
    - 12/26c-5 Beatrice fm net also excludes a single COAL layer (net where COAL flag<0.5).
  - Beatrice Fm: **NET RESERVOIR** where VSH<0.5 fr and PHIE>0.1 fr (kah >=1mD).
  - Dunrobin Bay Gp: **NET RESERVOIR** where VSH<0.5 fr and PHIE>0.06 fr (kah >=1mD).

- Contacts.
  - 12/26c-5 Beatrice Fm, observed OWC* at 7005ftMD, 6856ftTVDSS (~2090mTVDSS).
    - Composite log reports good OIL show at 6971ftMD. Some weak oil shows at and below 7067ftMD.
  - 12/27-1 Beatrice Fm, observed GWC at 3676ftMD, 3552ftTVDSS (~1083mTVDSS). Porosity reduces with depth here, and it could be a GDT, but logs definitely show WATER in Dunrobin sand below 3715ftMD, 3591ftTVDSS (~1095mTVDSS). If Beatrice & Dunrobin connected, then GWC between 1083-1095mTVDSS.
    - DST 3 (Beatrice) recorded 5.6-9.5 mmscfd GAS. Oil shows (staining) seen in core across Beatrice and Dunrobin.

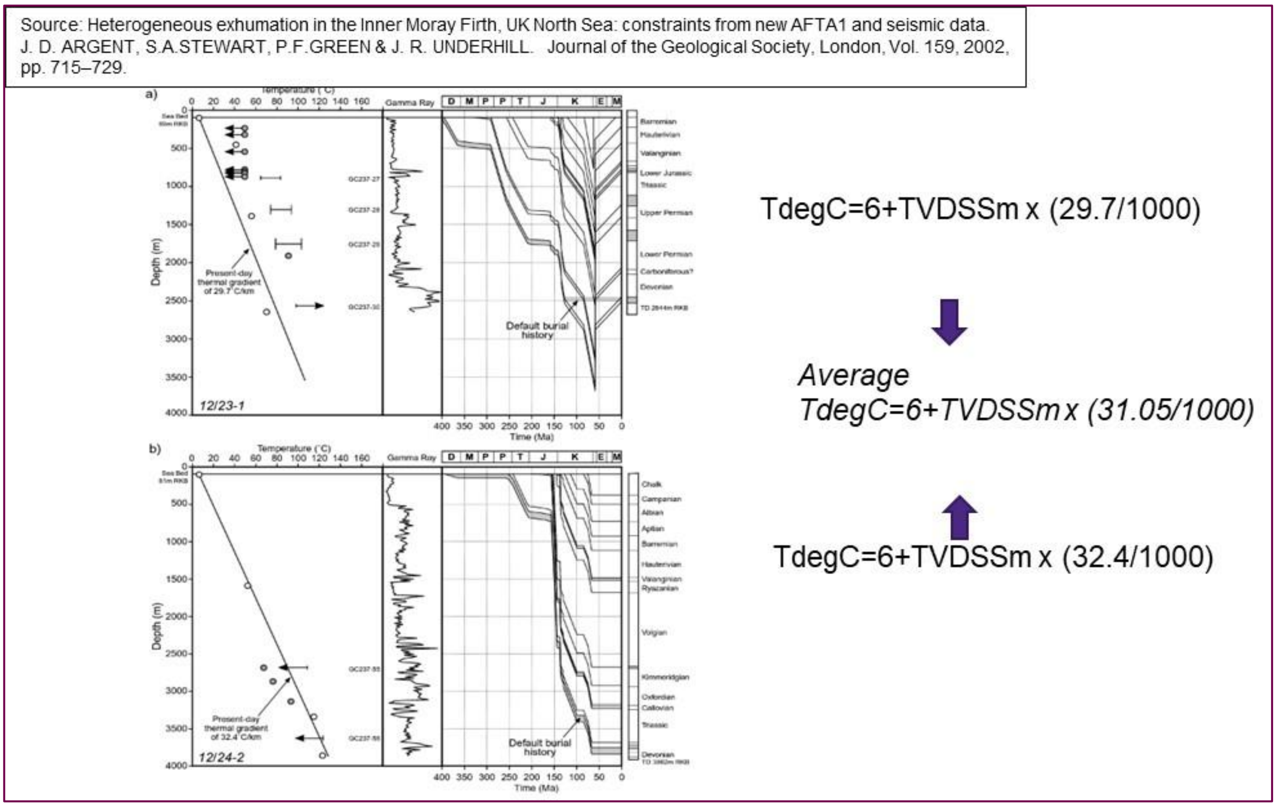

Figure 5.9: Burial History and Formation Temperature from Average Moray Firth Geothermal Gradient

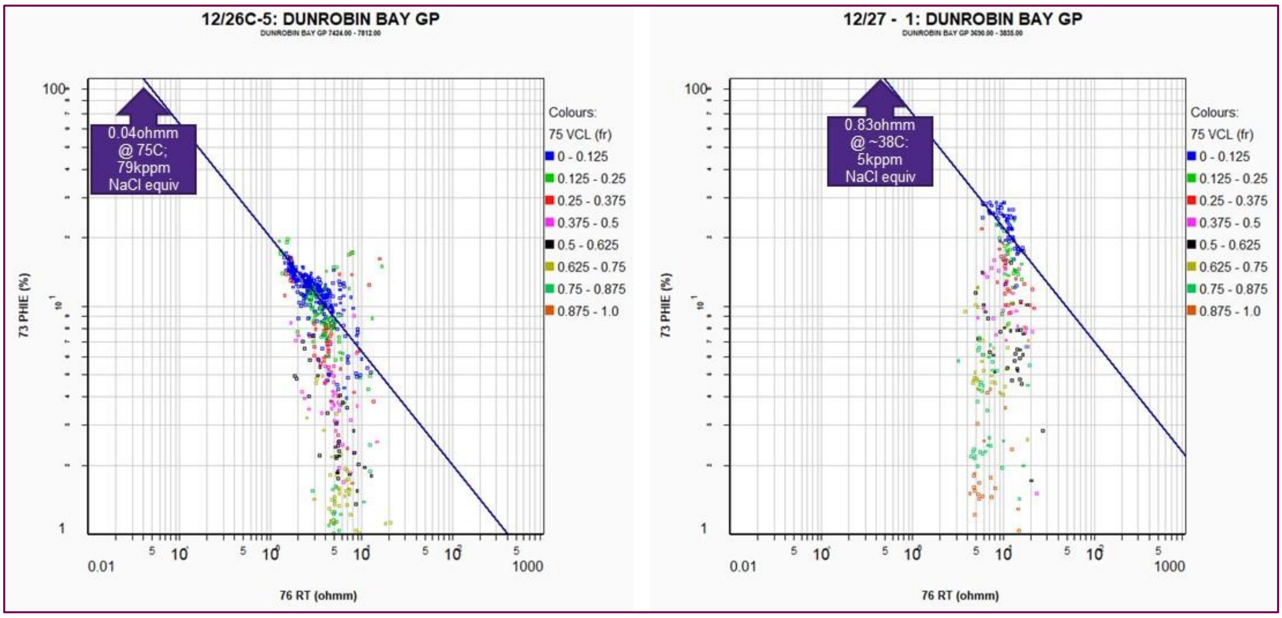

Figure 5.10: Pickett Plots for 12/26c-5 and 12/27-1

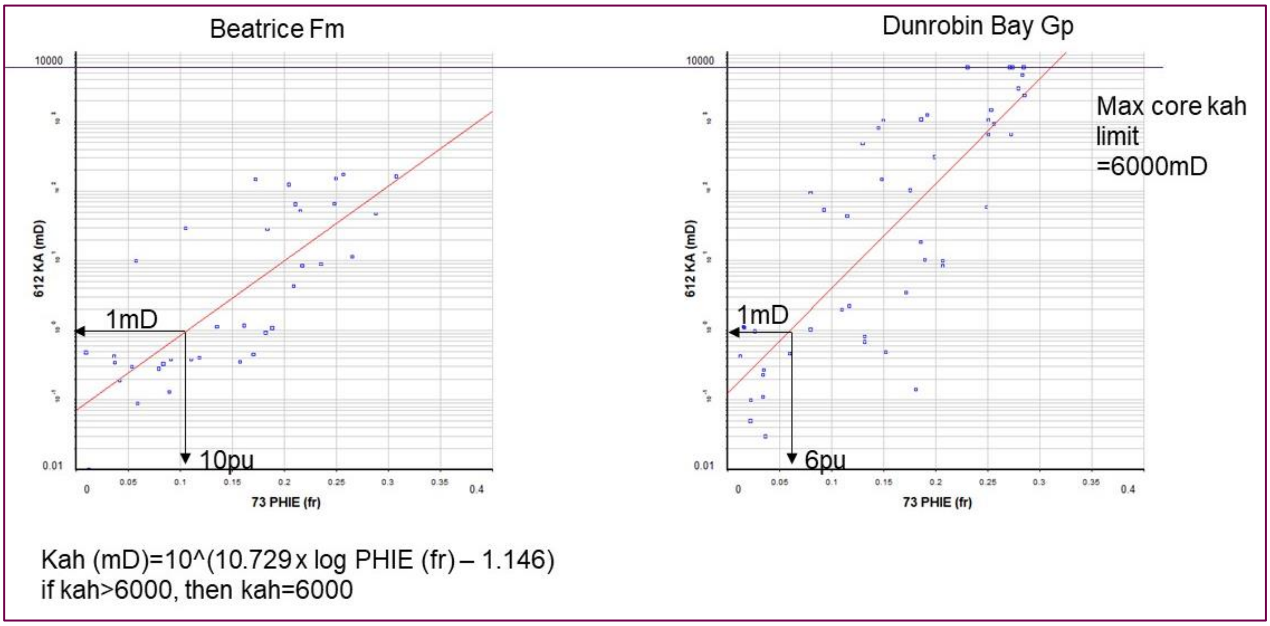

Figure 5.11: 12/27-1 Log PHIE vs Core KAH – Core Points Depth Shifted to Match Logs

5.3.2.2 CPI Plots

Figure 5.12 contains RPS's CPI plot for the Jurassic interval in well 12/27-1. The interpreted VSH, PHIE, SWE and permeability values are shown calibrated against core results and cuttings lithology. The interpreted GWC from logs is shown by the horizontal dashed line.

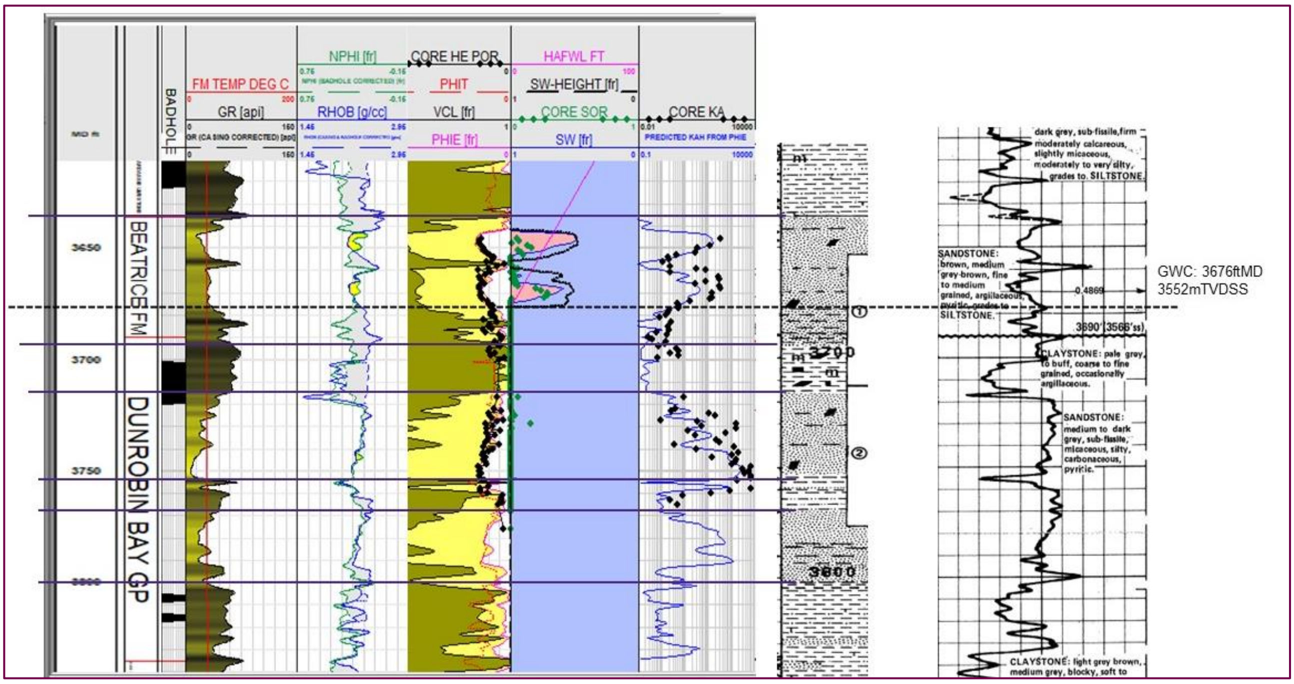

Figure 5.12: RPS CPI 12/27-1 – Across Jurassic

Figure 5.13 contains RPS's CPI plot for the Jurassic interval in well 12/26c-5, with an expanded section across the Beatrice Formation in Figure 5.14 highlighting the observed OWC from logs shown by the horizontal dashed line.

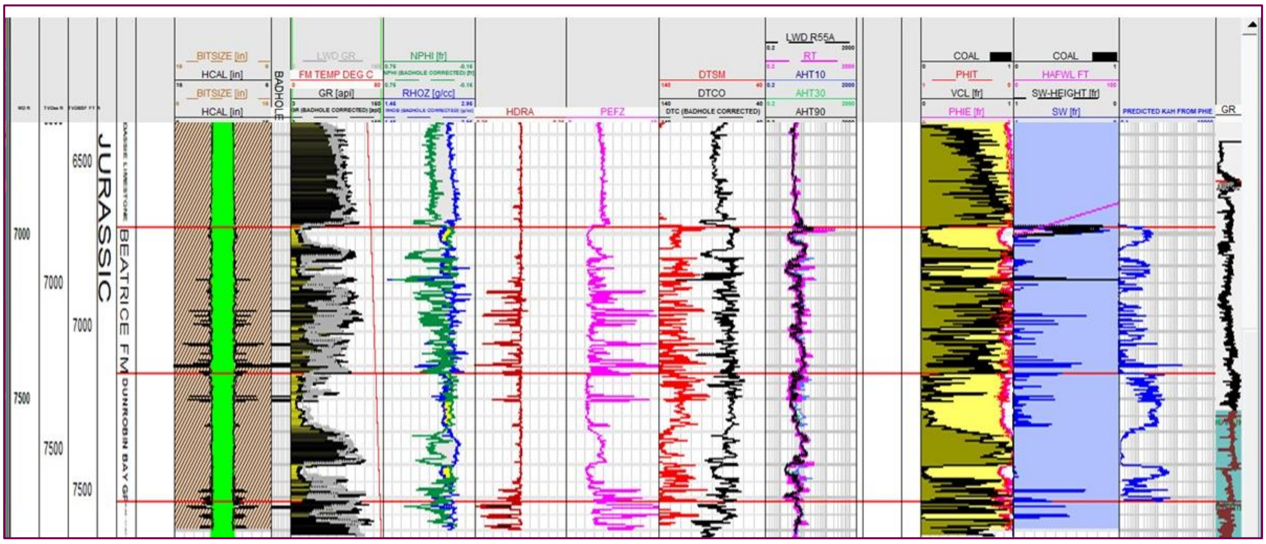

Figure 5.13: RPS CPI 12/26c-5 - Across Jurassic

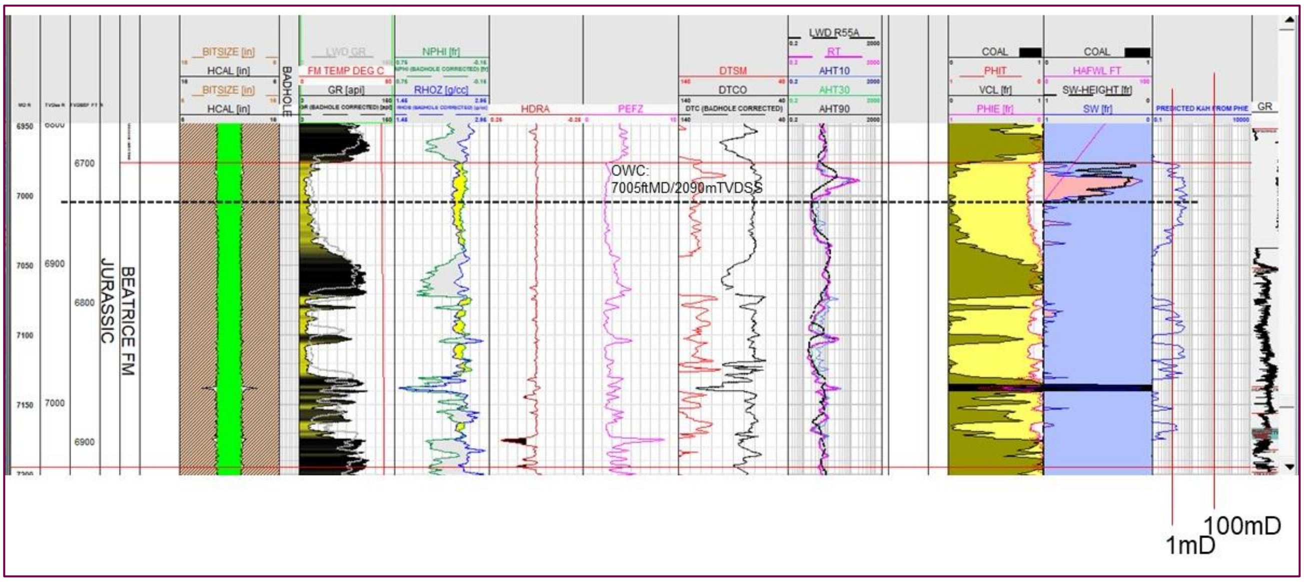

Figure 5.14: RPS CPI 12/26c-5 Expanded View Across Beatrice Formation Showing Oil-Water Contact

5.3.2.3 Petrophysical Zone Averages

Table 5-2 shows the petrophysical zone sums from 12/27-1 and 12/26c-5 using the cutoffs described in section 5.3.2.1.

Zone	Top_MD	Base_MD	Top_TVDSS	Base_TVD SS	Gross	Net	NTG	Net Res	NRTG	Net			Net Reservoir		
										VSH	PHIE	SWE	VSH	PHIE	SWE
	ft	ft	ft	ft	ft	ft	fr	ft	ft	fr	fr	fr	fr	fr	fr
12/27-1															
Kimmeridge Clay Fm	2457	3048	2332.94	2923.89	591.00	370.00	0.626	0.00	0.000	0.258					
Heather Fm	3048	3443	2923.89	3318.84	395.00	281.50	0.710	0.00	0.000	0.259					
Ardassie Limestone	3443	3636	3318.84	3511.77	193.00	54.50	0.282	0.50	0.003	0.232	0.079	1.000	0.379	0.105	1.000
Beatrice Fm	3636	3690	3511.77	3565.75	54.00	39.50	0.731	33.50	0.620	0.132	0.203	0.729	0.103	0.229	0.717
Dunrobin Bay GP	3690	3835	3565.75	371.067	145.00	71.50	0.493	71.00	0.490	0.175	0.179	1.000	0.172	0.181	1.000
Red Beds /Golspie Fm	3835	3967	3710.67	3842.58	132.00	58.50	0.443	58.50	0.443	0.194	0.150	1.000	0.194	0.150	1.000
Stotfield / Top Triassic	3967	4000	3842.58	3875.56	33.50	33.50	1.000	0.00	0.000	0.003	0.051	1.000			
Beatrice Gas Zone	3636	3676	3511.77	3551.75	40.50	35.00	0.864	30.00	0.741	0.103	0.214	0.711	0.078	0.241	0.700
Top Beatrice-Base Red Beds	3636	3967	3511.77	3842.58	331.00	169.50	0.512	163.00	0.492	0.172	0.175	0.927	0.166	0.179	0.926
12/26C-5															
Kimmeridge Clay Fm	3332	6005	3183.98	5856.95	2673.00	0.00	0.000	0.00	0.000						
Heather Fm	6005	6606	5856.95	6457.80	601.00	0.00	0.000	0.00	0.000						
Ardassie Limestone	6606	6976	6457.80	6827.51	370.00	126.00	0.341	0.50	0.001	0.262	0.046	1.000	0.000	0.106	1.000
Beatrice Fm	6976	7424	6827.51	7274.98	448.00	210.50	0.470	112.00	0.250	0.167	0.100	0.868	0.072	0.136	0.826
Dunrobin Bay GP	7424	7812	7274.98	7662.53	388.00	247.50	0.638	207.50	0.535	0.135	0.101	0.959	0.102	0.112	0.956
Red Beds /Golspie Fm	7812	7935	7662.53	7785.40	123.00	47.00	0.382	15.50	0.126	0.158	0.059	0.782	0.076	0.116	0.695
Stotfield / Top Triassic	7935	9999	7785.40		26.50	0.00	0.000	0.00	0.000						
Beatrice Gas Zone	6976	7005	6827.51	6856.48	29.50	29.50	1.000	25.00	0.847	0.055	0.138	0.562	0.034	0.147	0.519
Top Beatrice-Base Red Beds	6976	7935	6827.51	7785.40	959.00	505.00	0.527	335.00	0.349	0.151	0.097	0.910	0.091	0.120	0.895

Cutoffs used:

Beatrice Fm: NET VSH<0.5, NET RES VSH<0.5 and PHIE>0.1 (and excluding COAL in 12/26c-5)

Dunrobin Bay Gp-Red Beds: NET VSH < 0.5, NET RES VSH<0.5 and PHIE>0.06

VSH and PHIE is thickness weighted *SWE is thickness and porosity weighted*

Table 5-2: Summary of Petrophysical Zone Sums and Averages from 12/27-1 and 12/26c-5 Using Cutoffs Described in Section 5.3.2.1

5.3.3 Geophysical Evaluation and Audit

5.3.3.1 Fluid substitution

Fluid substitution was performed at the request of the client. The general workflow is as follows.

1. Wireline recorded logs and CPI was received from RPS petrophysicist,
2. Borehole corrected sonic, shear and density logs selected where applicable.
3. A database constructed in Hampson Russell v11.0.4 incorporating logs, deviation surveys and tops.
4. Standard fluid substitution routine applied.
    a. The insitu fluids, guided by the Sw log, were substituted for brine.
    b. The brine logs were substituted for oil or gas in the required intervals as requested by the client.
    c. Batzle Wang was chosen for all fluid calculations, porosity calculated from density, Hashin-Shtrikman matrix averaging keyed on Vcl log, remainder assumed to be quartz. Substitution of insitu logs to brine case excludes Vcl > 0.5 or Sw > 0.9, substitution of brine logs to oil/gas excludes Vcl > 0.5

For well 12/26c-5, RPS was tasked with substituting in situ with oil in the reservoir intervals. The recorded shear had inappropriate values, particularly in the sands and was therefore replaced with a modelled version. Note that the Beatrice Fm initial condition is partial oil saturation. Results are shown in Figure 5.15.

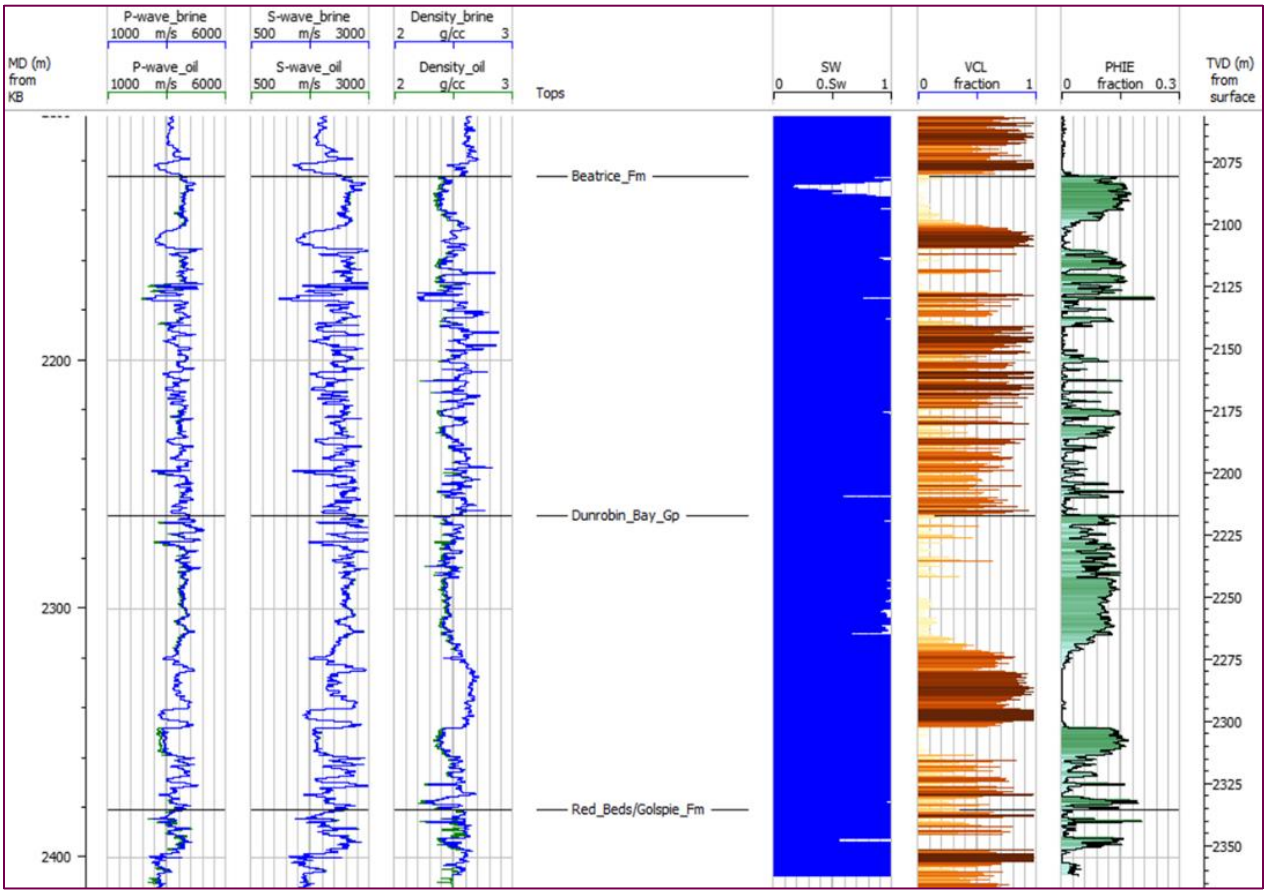

Figure 5.15: Well 12/26c-5 Brine and Oil Logs

For well 12/27-1, RPS was tasked with generating a modelled shear log then substituting in situ gas with brine, then substituting Beatrice and Dunrobin reservoir intervals with gas, 38API oil and 20API oil. The results are shown in Figure 5.16.

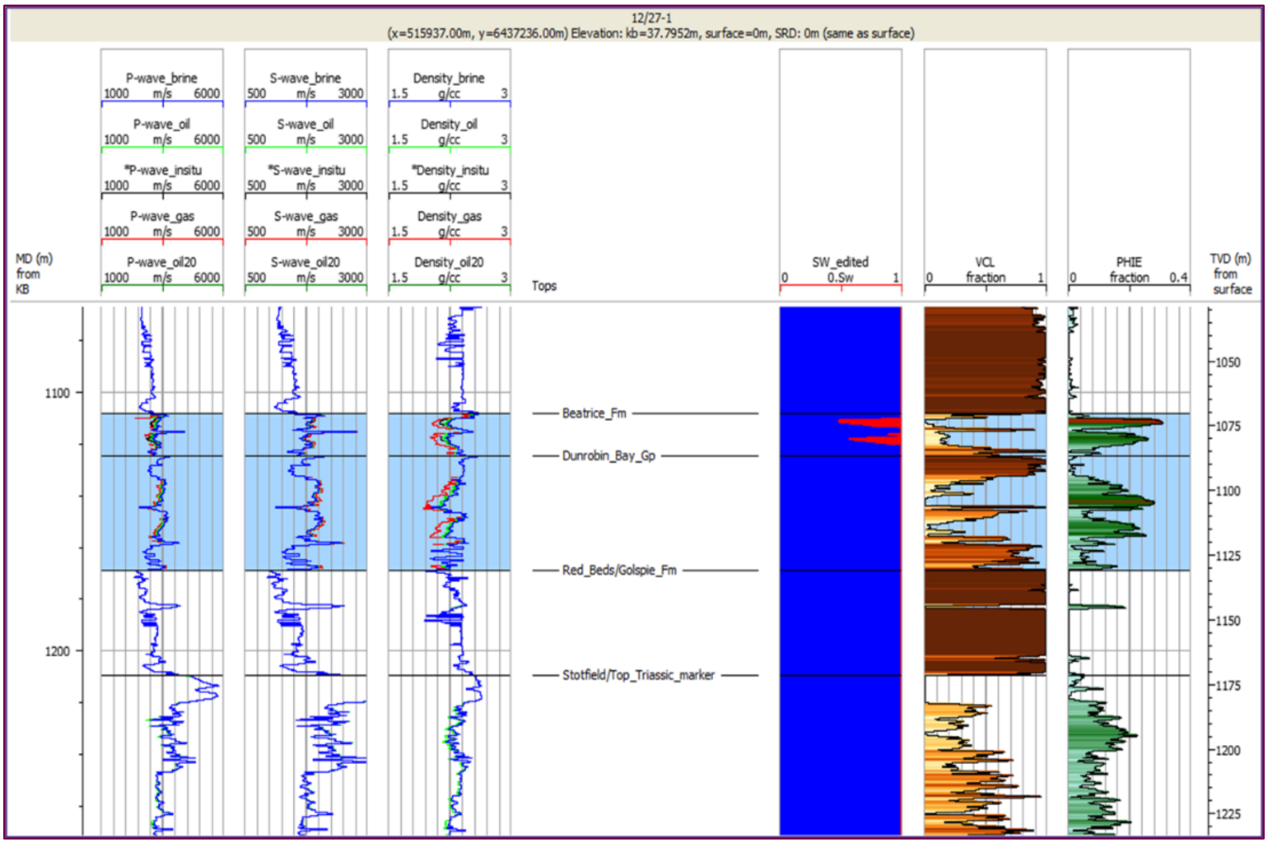

Figure 5.16: Well 12/27-1 In situ, Brine, Gas, 38API Oil, and 20API Oil Logs

5.3.3.2 Interpretation and Depth Conversion

For the purposes of this assessment RPS was provided with a single 3D seismic dataset (including Near, Far and Full stacks) and 18 2D seismic lines (full stack) across the P2478 licence (Figure 5.17). The 3D data were acquired by PGS in 2006 and reprocessed by Reabold in 2022. The reprocessing focussed on removing shallow water bottom multiples which had hindered the interpretation of the relatively shallow Dunrobin prospects.

The 2D data were also re-processed and tied to the 3D so as to allow a consistent interpretation of the Dunrobin West prospect which extends off the 3D to the southwest. The 2D data were acquired between 1985 and 1997 (Figure 5.17).

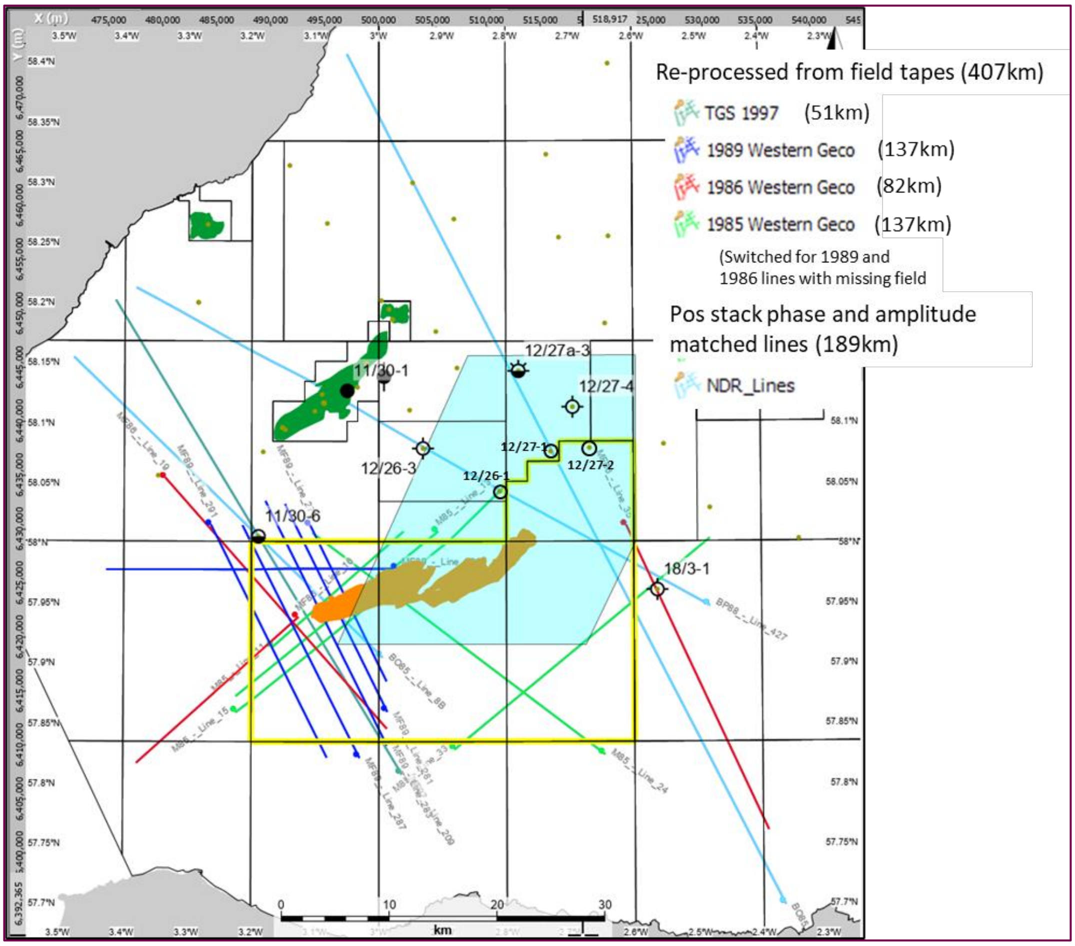

Figure 5.17: Database provided by Reabold for the P2478 Licence[9]

In addition to the seismic data, various well logs and reports were provided for eight wells, located within or close to the P2478 licence. These wells were selected by Reabold following requests from RPS Energy.

To support the resource assessment Reabold provided time and depth maps for the Top Beatrice and Top Triassic (Stotfield Chert) levels, in two-way time (milliseconds) and depth (mTVDSS). Fault polygons were also provided along with seismic horizons and grids for the Sea Floor, Ardassie Limestone and Base Cretaceous Unconformity in two-way time (milliseconds).

Lastly Reabold provided various presentations and reports which detailed their own geological and geophysical interpretation and resource assessment.

RPS did not carry out any new seismic interpretation as the time and depth maps provided by Reabold were assessed to be a reasonable interpretation of the seismic and well data provided. The key depth surfaces were checked with respect to their intersections at the wells and found to be tied correctly.

The depth conversion methodology was detailed within the presentation material supplied by Reabold which demonstrated that several iterations of velocity modelling had taken place since 2020. The most recent approach used a 3D horizon-based velocity model where mapped intervals were flooded with interval velocities from six wells lying to the north of the P2478 licence. Unfortunately, since no well data exists to the south of, or within, the P2478 licence the velocity model is relatively unconstrained in the southern portion of P2478, and particularly in the hanging wall of the main east-west fault which sets-up the Dunrobin prospect closures (Figure 5.18).

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[9] *P2478 Technical Committee Meeting 3rd October 2022*

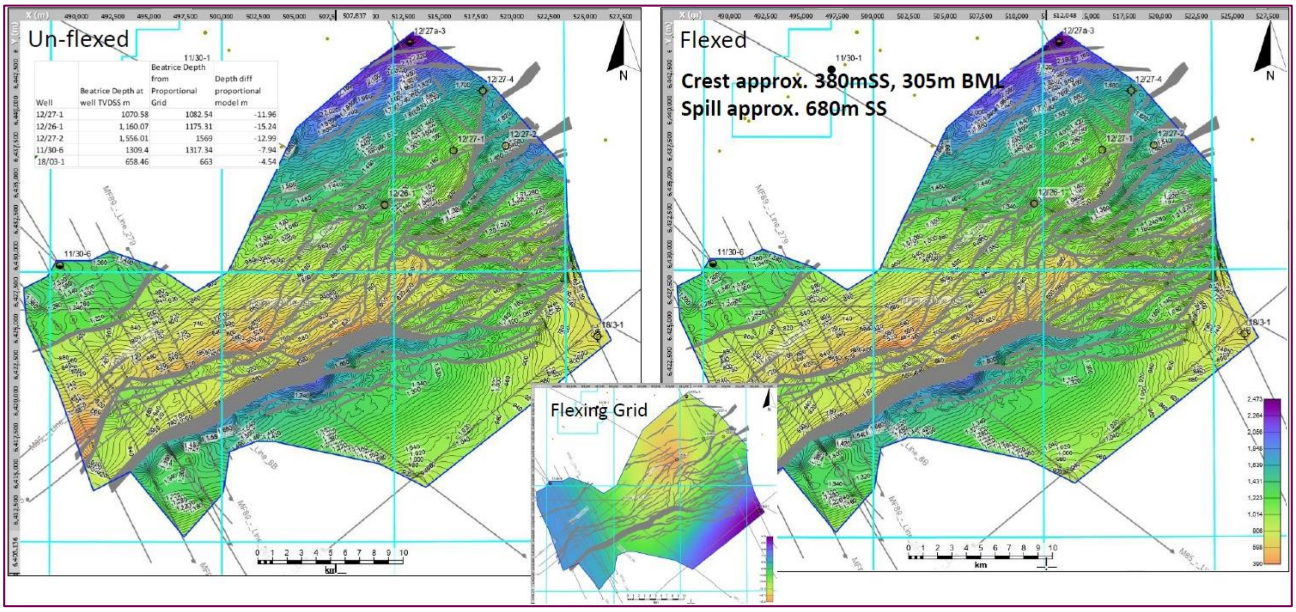


Figure 5.18: Beatrice Depth Structure Map, Residuals and Flexed Map following 'Model 1' Depth Conversion[10]

5.3.3.2.1 P2478 Prospect Interpretation

Three prospects have been assessed on the P2478 Licence: Dunrobin West, Dunrobin Central and East and Golspie (Figure 5.3). All three prospects are mapped as three-way footwall closures against northeast-southwest trending normal faults at the Beatrice and Triassic seismic horizons.

The Dunrobin closures are relatively shallow with less than 400m of overburden at the Beatrice level (Figure 5.18), whilst the Golspie crest is deeper with around 800m of overburden at the Beatrice level. The Dunrobin West and Central and East closures are closely related and separated by a single normal fault. Reabold have in some cases assessed the closures to have a common spill and potential for communication across the fault, however we have treated the two closures separately for the purposes of this report.

The level of faulting is more intense within the Dunrobin Central and East closure, whilst Golspie and Dunrobin West are generally unfaulted apart from their bounding fault.

Overall, the seismic interpretation provided by Reabold is consistent and sufficiently detailed to define the prospect closures, although where the data become noisy and less coherent at the crest of Dunrobin West, the horizons maybe potentially more model driven (Figure 5.19). The fault mapping is also detailed and nicely depicts the primary and secondary faults observed on the amplitude maps and coherency attributes (Figure 5.20).

The key horizons used for defining the prospects are the Top Beatrice and Top Triassic. Both surfaces are picked across the extent of the 3D seismic and onto the 2D seismic, particularly in the southwest where the Dunrobin West closure extends beyond the 3D (Figure 5.21).

The seismic events between the Top Beatrice and Top Triassic are conformable and generally thin onto structure (particularly at Dunrobin Central and East), suggesting that some structural topography was present at the time of deposition. The seismic facies are fairly planar, with no obvious incision, mounding or onlapping suggesting that the reservoir units are laterally continuous within the closure area (i.e. no obvious fan or channel boundaries).

Above the Beatrice unit the seismic stratigraphy shows onlap onto the BCU, highlighting an initial uplift (and potentially early trapping) during the late Jurassic. The most significant uplift occurred during the early Cenozoic, and it is this phase of structuration than has created the present-day trapping configuration and

[10] *P2478 Technical Committee Meeting 3rd October 2022*

main phase of footwall uplift. Figure 5.7 highlights this burial history and shows that up to 1000m of Jurassic and Cretaceous sediments may have been removed from the crest of the Dunrobin closures. Overall, the burial history is favourable for the timing of reservoir, seal and charge, as the Devonian peak oil charge is recent. However, this late phase of uplift may have reduced seal capacity and any earlier accumulations may have been lost.

Since the closures are all reliant on fault seal, Reabold have conducted a series of allen diagrams along the bounding faults to identify any points of potential leakage through juxtaposition with sand prone facies in the hanging wall. Figure 5.22 shows that there is a potential for the Dunrobin Central and East top Beatrice (hanging wall) to juxtapose against the Triassic within the Dunrobin West closure (footwall), however this is only below 540ms TWT and the amount of juxtaposition is within the expected depth conversion uncertainty range. The main bounding fault along the Dunrobin Central and East closure is expected to be laterally sealing as the reservoir units are juxtaposed against mud prone Volgian and Upper Jurassic sediments (KCF) in the hanging-wall, although there is no well control in the hanging-wall to confirm this.

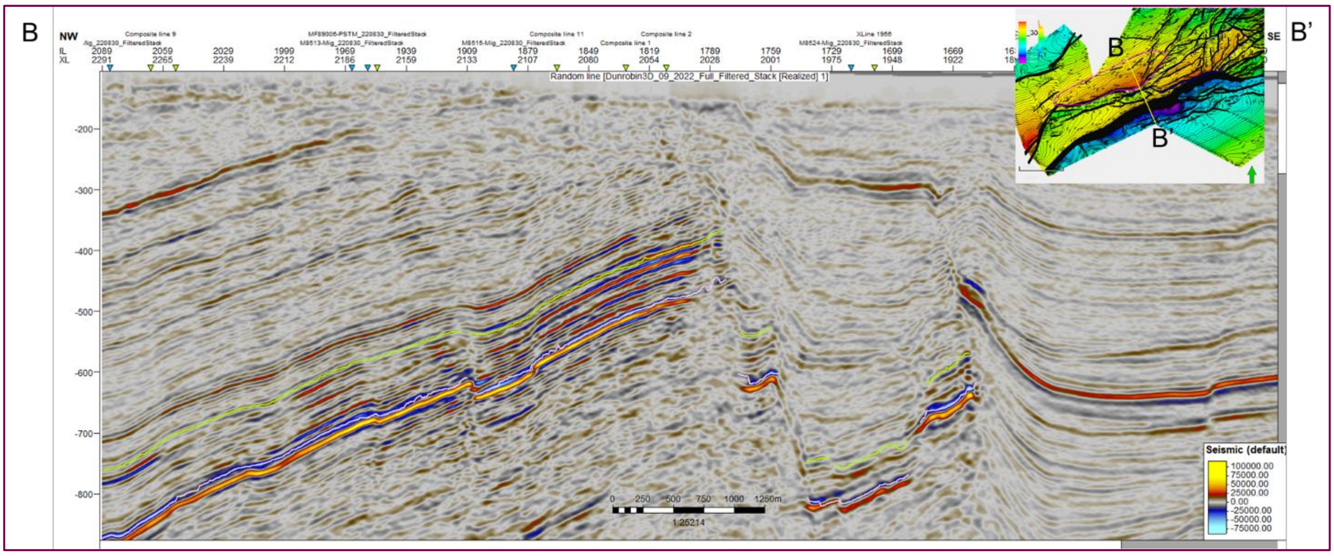


Figure 5.19: 3D Seismic Section (TWT) through Dunrobin West[11]

[11] *Generated by RPS Energy in Petrel*

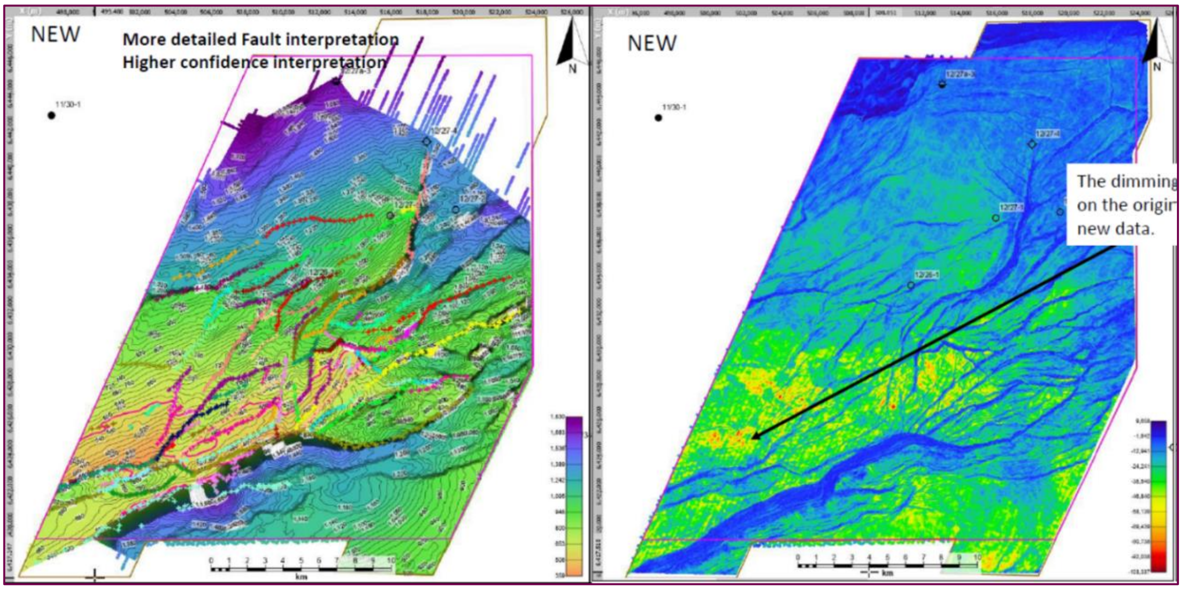


Figure 5.20: Triassic Depth Structure Map, and Max Amplitude Map over P2478[12]

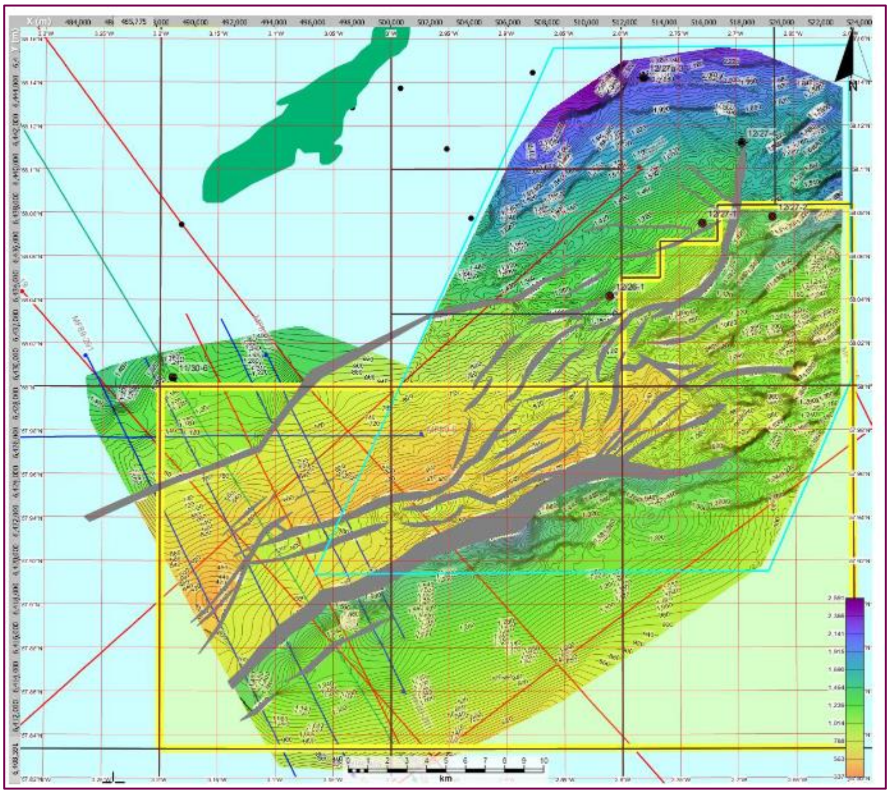


Figure 5.21: Top Beatrice TWT Structure Map showing extent of 3D Seismic Coverage (blue outline) and 2D Seismic Lines used to confirm Closure[13]

[12] *Modified from P2478 Technical Committee Meeting 3rd October 2022*

[13] *Modified from P2478 Technical Committee Meeting 3rd October 2022*

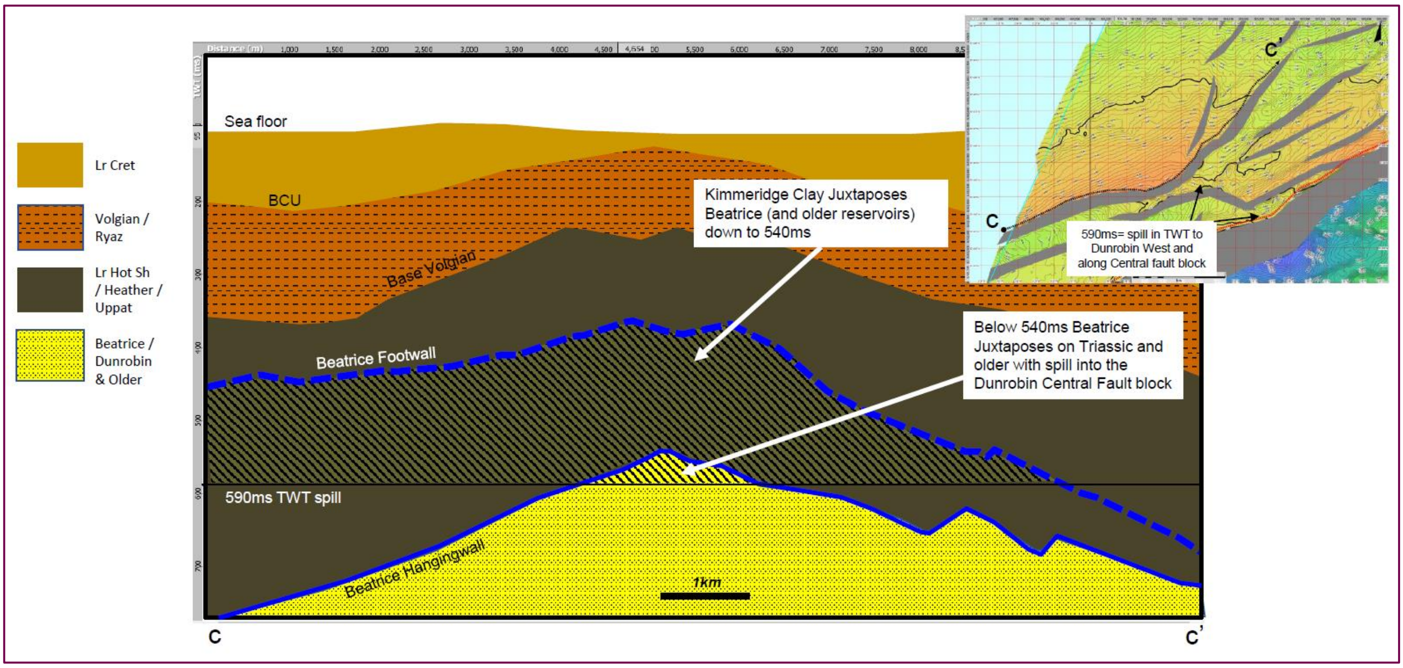


Figure 5.22: Allen Diagram along Dunrobin West Bounding Fault [14]

The seismic response at the two main reservoir levels (Beatrice and Triassic) is consistent and easy to define across all three prospects, apart from the crest of Dunrobin West, where the structure is shallow and the data noisy (Figure 5.23). The Beatrice horizon has been picked on a strong peak (negative acoustic impedance) which represents the top of the Beatrice sand, and the Triassic horizon has been picked on a strong trough (positive acoustic impedance), which represents the Stotfield Chert Member.

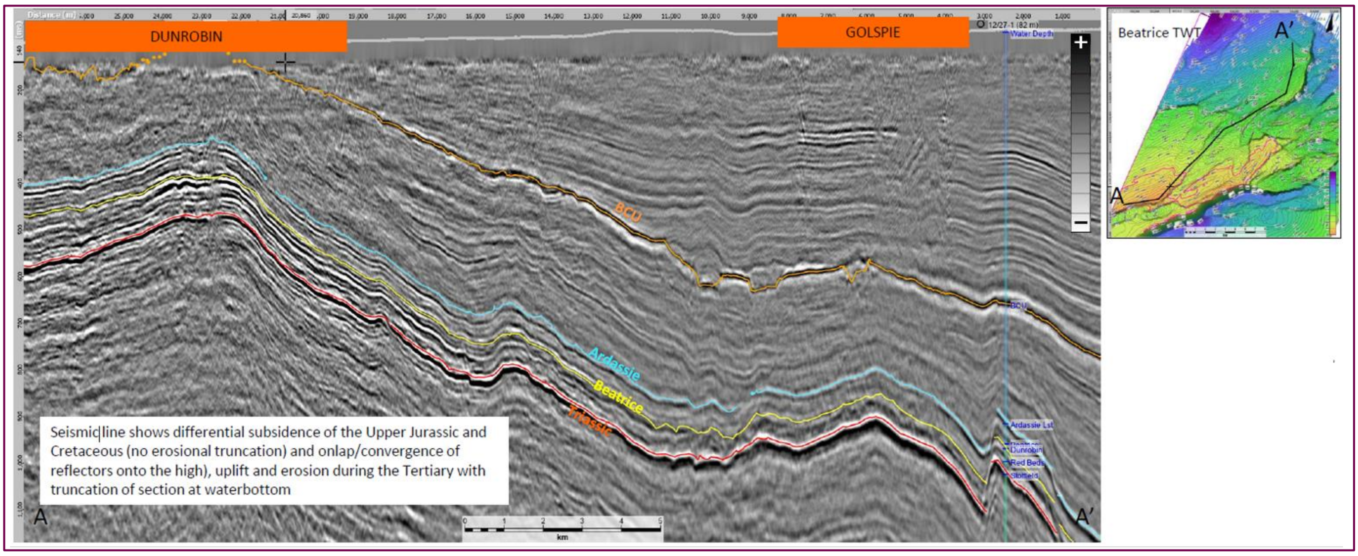


Figure 5.23: Seismic Correlation to 12/27-1 Well [15]

Amplitude extractions at the Beatrice level show a brightening into the crest of the Dunrobin West prospect (Figure 5.24 and Figure 5.26) which is interpreted as a possible gas cap and a gas oil contact at the point where the amplitudes dim (~470m TVDSS). The anomaly at Dunrobin West also appears to show an

[14] *Modified from P2478 Technical Committee Meeting 3rd October 2022*

[15] *P2478 Technical Committee Meeting 3rd October 2022*

increasing negative acoustic impedance from the near to the far stack suggesting an AVO and supporting the presence of a gas cap at this location (Figure 5.25).

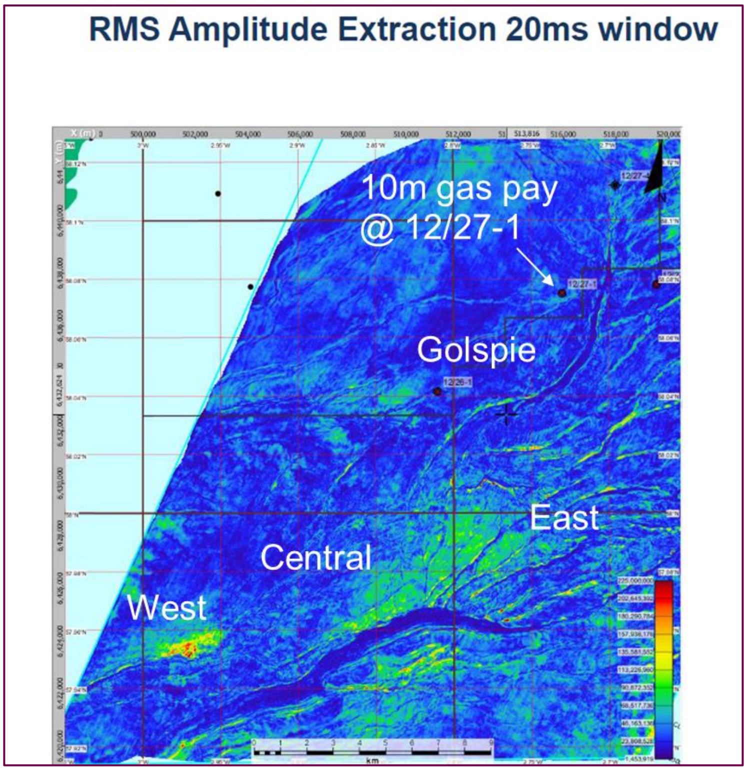


Figure 5.24: RMS Amplitude Extraction over the Beatrice Horizon[16]

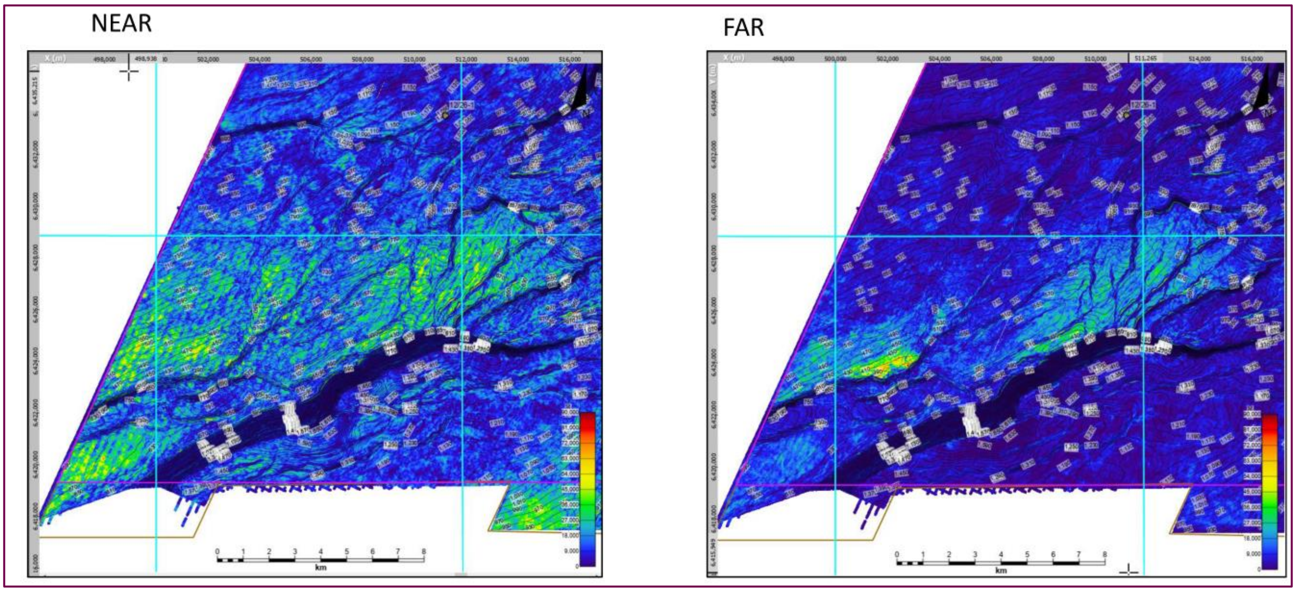
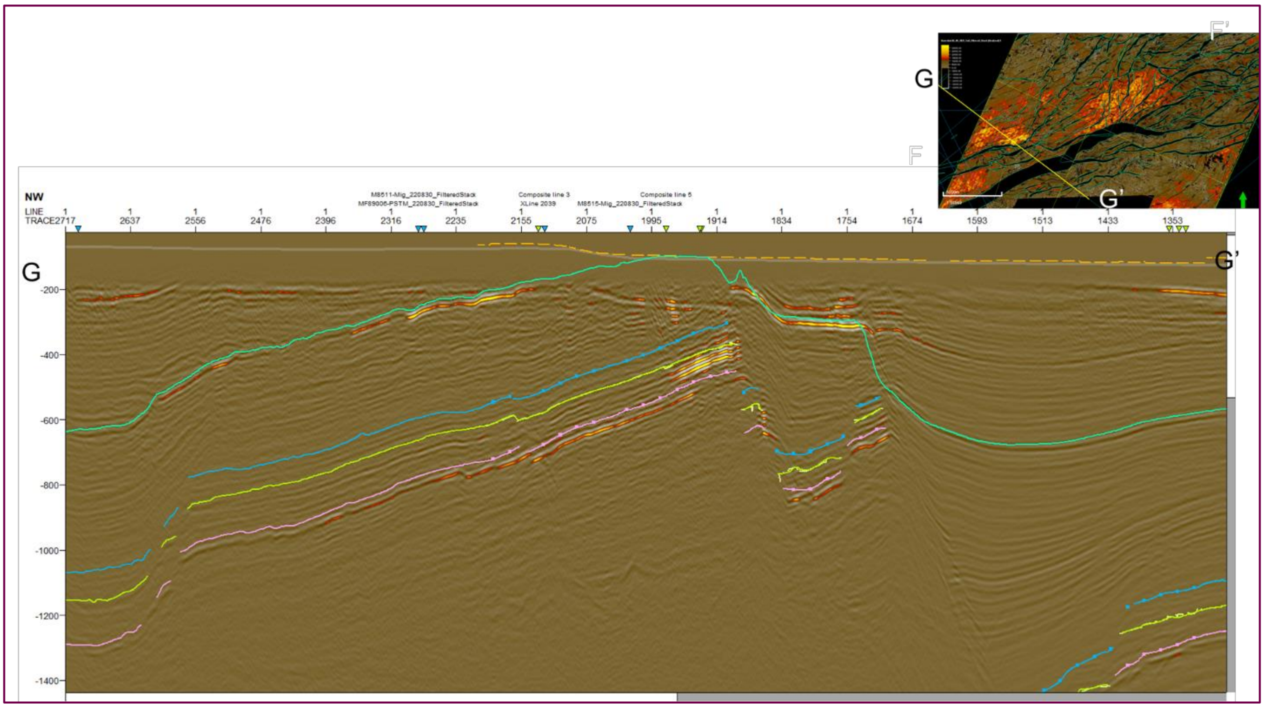


Figure 5.25: Max Amplitude Extraction over the Beatrice Horizon on the Near and Far stacks[17]

[16] *Modified from P2478 Technical Committee Meeting 3rd October 2022*

[17] *Modified from P2478 Technical Committee Meeting 3rd October 2022*



18

Figure 5.26: Seismic Section through the Dunrobin West Closure (Full Stack) showing brightening on structure beneath the Top Beatrice Horizon (green)

The Dunrobin Central and East structure also shows an increased negative acoustic impedance amplitude response within closure at the Beatrice level, however, there is no distinct increase towards the crest, and the overall amplitude anomaly is weaker and more disperse than at Dunrobin West. There is also no apparent difference from the near to the far stack. RPS does not have sufficient confidence in the data or the anomaly to interpret this as a direct hydrocarbon indicator, as the anomaly may indicate porosity/lithology changes where the overburden is reduced and/or a general tuning effect, since the amplitude is consistent with a thinning isochore between the Beatrice and Triassic.

The Golspie Prospect shows no amplitude anomaly at the Beatrice level. This may be indicative of poorer reservoir, a lack of hydrocarbons or just the depth of burial and seismic response at this deeper level. It should be noted that there is no amplitude anomaly around the 12/27-1 well at the Beatrice level, where a 10m gas cap was proven through logging and testing. This suggests that thin pay (<~20m) is unlikely to be resolved by the seismic data.

No significant amplitude anomalies or DHI's were observed at the Triassic level.

5.3.4 In-place Volumetric Assessment and Risking

In determining the GRV for each of the prospects we have used the depth maps provided by Reabold and extracted area/depth pairs from the top Beatrice and Top Triassic. The Jurassic (Beatrice & Dunrobin Bay Gp) and Triassic (Stotfield) reservoir sequences were assessed separately since in most cases they are interpreted to represent separate columns with a vertical seal between the Triassic and Jurassic reservoirs. In the case of the Dunrobin Central and East prospect we observed clear juxtaposition of the Jurassic and Triassic reservoirs across internal faults, and these reservoirs are assumed to be in communication and the Triassic has been assessed using the same contacts as the Jurassic.

For all of the prospects the Jurassic GRV was estimated between the Top Beatrice surface and a surface 'ghosted up' by 50m from the Top Triassic surface (Table 5-3). The offset from the Triassic was to exclude the Golspie Formation which is considered non-reservoir by Reabold (Figure 5.27).

[18] *Generated by RPS Energy in Petrel*

For the Triassic the GRV was estimated between the Top Triassic surface, 'ghosted down' by 25m to exclude the Stotfield Chert member, and a range of reservoir gross thickness based on the offset wells (Table 5-4 and Figure 5.27). The range of reservoir thickness was in most cases greater than the estimated column height. Overall the approach we have taken to calculating the GRV is very similar to Reabold's.

In calculating the potential hydrocarbon pay we assumed a range of contacts based on 100m column height or less at the P90 and the lowest closing contour as the P10 (Table 5-5). We have chosen the P90 column height to represent a realistic low case scenario, when considering the shallow overburden and uncertain nature of the column height retention capacity. The choice is also based on a review of column height data in the North Sea (Figure 5.28). For the Dunrobin West prospect we tested the potential maximum column height that could be retained based on assumed lithostatic, fluid and hydrocarbon pressure gradients, and including a gas cap. This highlighted that the LCC of 680 mTVDSS was at or near the maximum possible column height of 400m (Figure 5.29).

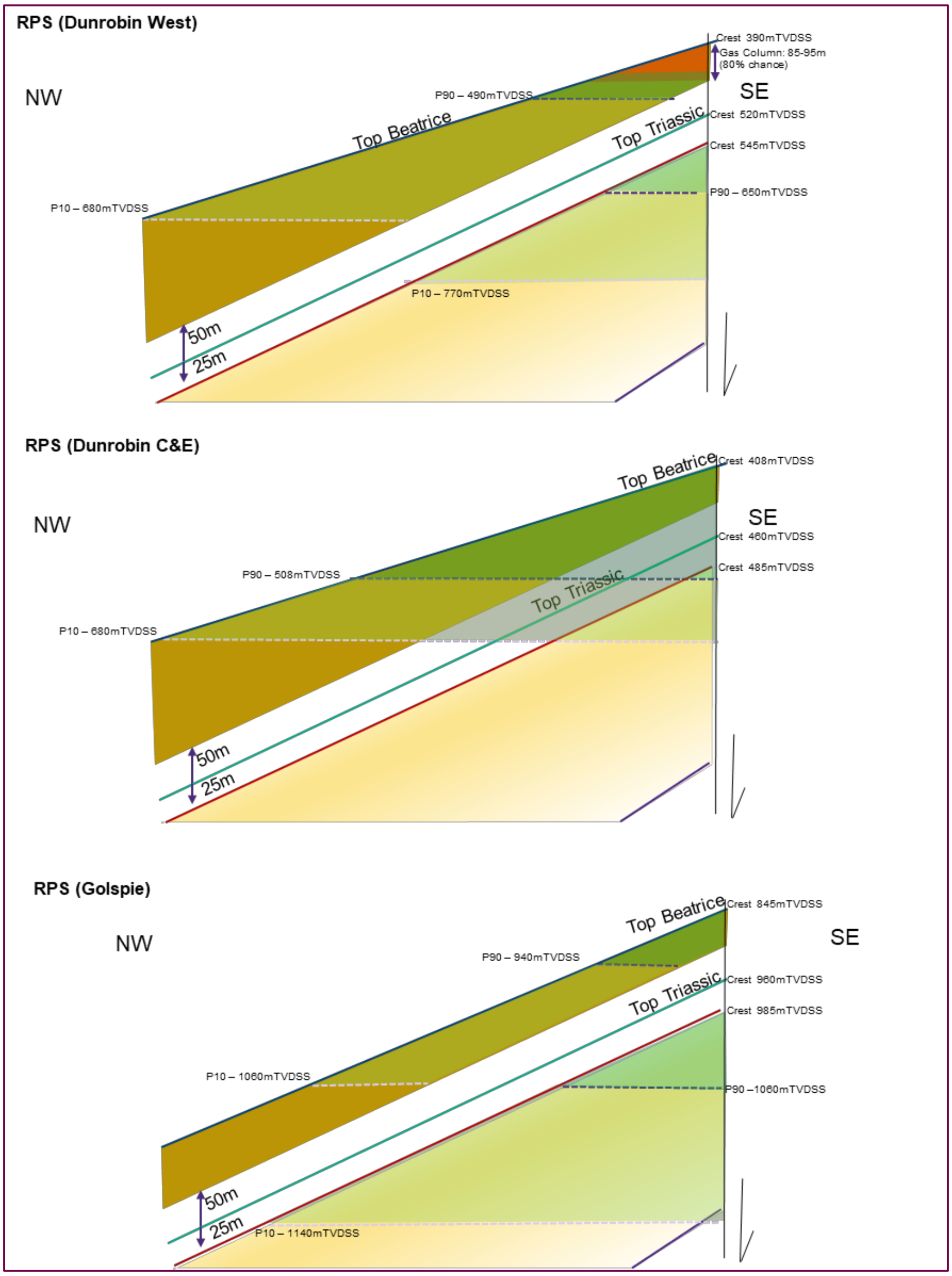


Figure 5.27: Cartoon Depicting GRV and Column Estimation Methodologies for the P2478 Prospects

For the reservoir quality parameters, we have used offset wells (including the petrophysical averages calculated by RPS for the 12/27-1 and 12/26c-5 wells) in the vicinity of the prospects to provide a range of potential porosity and net to gross averages. We have also included the 11/29-1 well to the southwest of the Dunrobin prospects to represent the poorer quality end of the reservoir fairway. For the porosity ranges we have allowed a slight uplift to reflect the shallow nature of the current traps compared to the offset wells (which are more deeply buried) but have also allowed for a deeper burial of the reservoirs prior to the Cenozoic uplift.

For the fluid parameters (FVF & GOR) we have taken into account the shallow nature of the traps, the waxy nature of the source rock characteristics and the recovered oils from the Beatrice field and the 12/27-1 well.

In all cases we have assumed that the traps will be charged by the Devonian source kitchen, which is oil prone and currently within the peak oil window. Based on the seismic amplitude at the Dunrobin West prospect, and the gas recorded at the 12/27-1 well we have included an 80% chance of this prospect having a gas cap, and included a narrow range of gas column height (85-95m) based on the depth at which the amplitude changes on the seismic. Based on the isotopic signature of the gas in the 12/27-1 well, any non-associated gas encountered in the P2478 prospects is expected to be dry biogenic gas.

A range of oil recovery factors was assumed based on the expected viscosity and waxiness of the crude. Reabold provided study reports (APT & Petrophase) that predicted a 20°API oil at the Dunrobin West prospect with a viscosity of 100-200cP, based on a forecast reservoir temperature of 20°C. It should be noted that the nearby 11/30-6 well recovered a 37.5°API oil with a -2°C pour point whilst the 12/27-1 oils were between 20-30°API. Given the ongoing nature of the oil charge coupled with likely ongoing biodegradation at the P2478 prospects it is possible that a range of potential oils maybe discovered.

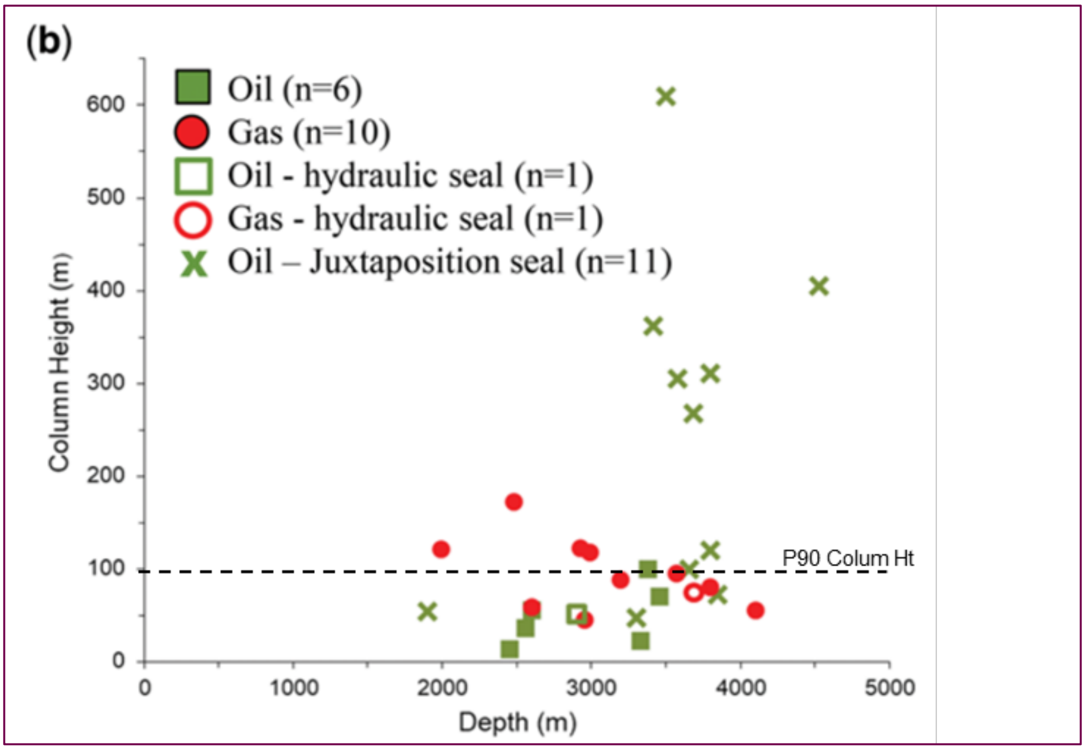


Figure 5.28: North Sea Column Heights vs Depth for Fault Traps[19]

[19] *Modified after Bretan el. al. 2019*

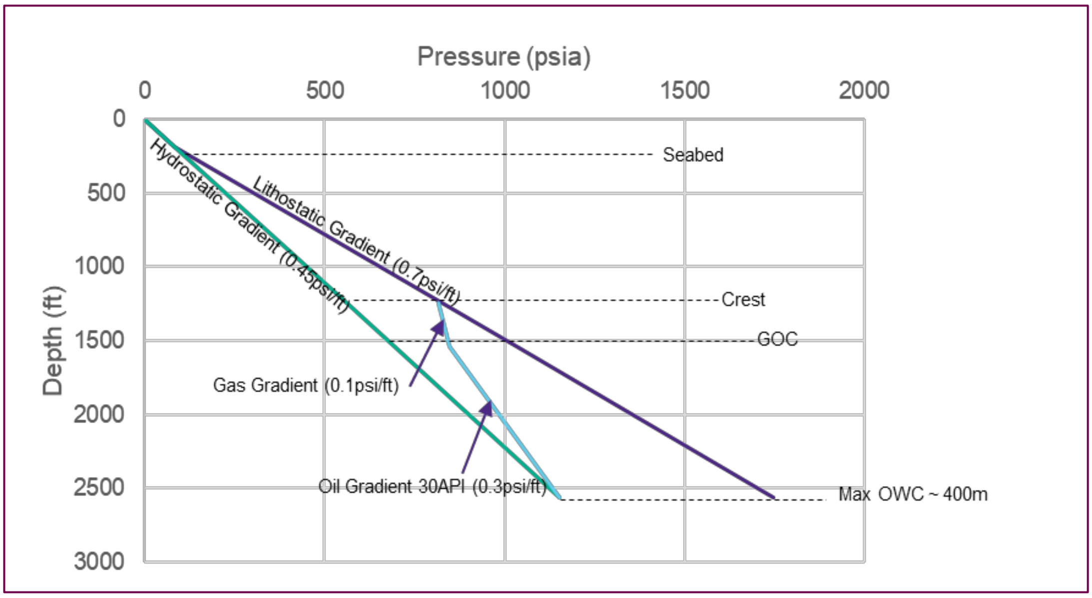


Figure 5.29: Estimation of Maximum Likely Column Height for the Dunrobin West Prospect

JURASSIC	Calculated GRV[1] (MMm^3)			
	P_{90}	P_{50}	P_{10}	Mean
Dunrobin West	73	461	1637	704
Dunrobin Central and East	13	74	662	209
Golspie	31	100	197	109

[1] *Gross Rock Volume as a function of area depth pairs and thickness*

Table 5-3: Calculated Gross Rock Volumes for Jurassic Targets

TRIASSIC	Calculated GRV[1] (MMm^3)			
	P_{90}	P_{50}	P_{10}	Mean
Dunrobin West	45	215	562	270
Dunrobin Central and East	6	58	325	129
Golspie	48	123	244	138

[1] *Gross Rock Volume as a function of area depth pairs and thickness*

Table 5-4: Calculated Gross Rock Volumes for Triassic Targets

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Base Reservoir Shift (m)	Single	-50	-50	-50	-50
Oil-Water Contact (mTVDSS)	Lognormal	490	577	680	582
Area Uncertainty (%)	Normal	95	100	105	100
Degree of Fill (%)	Single	100	100	100	100
Height of Gas Column (m)	Normal	85	90	95	90
Net to Gross (%)	Normal	30	41	52	41
Porosity (PHIE) (%)	Normal	20	24	28	24
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.04	1.05	1.06	1.05
GOR (scf/bbl)	Normal	100	110	120	110
Dry Gas Formation Volume Factor (1/Bg)	Normal	43	57	71	57
Oil Recovery Factor (%)	Normal	15	22.5	30	22.5
Gas Recovery Factor (%)	Normal	60	70	80	70

Table 5-5: Summary of Input Parameters for Dunrobin West (Jurassic) Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Thickness (m)	Normal	300	400	500	400
Shift Top Reservoir (m)	Single	25	25	25	25
Area uncertainty (%)	Normal	95	100	105	100
Oil-Water Contact (mTVDSS)	Lognormal	650	710	770	710
Net to Gross (%)	Normal	75	82.5	90	82.5
Porosity (PHIE) (%)	Normal	18	20	22	20
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.04	1.05	1.06	1.05
GOR (scf/bbl)	Normal	100	110	120	110
Oil Recovery Factor (%)	Normal	15	22.5	30	22.5

Table 5-6: Summary of Input Parameters for Dunrobin West (Triassic) Volumetrics

	STOIIP (MMstb)			
	Low	Best	High	Mean
Jurassic	31	194	735	313
Triassic	33	157	423	201

Table 5-7: Gross STOIIP for Dunrobin West

	GIIP (Bscf)			
	Low	Best	High	Mean
Jurassic	3	5	8	5

Table 5-8: Gross GIIP for Dunrobin West

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Shift Base Reservoir (m)	Single	-50	-50	-50	-50
Oil-Water Contact (mTVDSS)	Lognormal	508	588	680	592
Area Uncertainty (%)	Normal	95	100	105	100
Degree of Fill (%)	Single	100	100	100	100
Net to Gross (%)	Normal	35	43.5	52	43.5
Porosity (PHIE) (%)	Normal	20	24	28	24
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.04	1.05	1.06	1.05
GOR (scf/bbl)	Normal	100	110	120	110
Oil Recovery Factor (%)	Normal	15	22.5	30	22.5

Table 5-9: Summary of Input Parameters for Dunrobin Central and East (Jurassic) Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Thickness (m)	Normal	300	400	500	400
Shift Top Reservoir (%)	Single	25	25	25	25
Area Uncertainty (%)	Normal	95	100	105	100
Oil-Water Contact (mTVDSS)	Lognormal	523	598	682	1100
Net to Gross (%)	Normal	75	85	95	85
Porosity (PHIE) (%)	Normal	18	20	22	20
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.04	1.05	1.06	1.05
GOR (scf/bbl)	Normal	100	110	120	110
Oil Recovery Factor (%)	Normal	15	22.5	30	22.5

Table 5-10: Summary of Input Parameters for Dunrobin Central and East (Triassic) Volumetrics

	STOIIP (MMstb)			
	Low	Best	High	Mean
Jurassic	6	34	299	98
Triassic	5	43	247	98

Table 5-11: Gross STOIIP for Dunrobin Central and East

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Shift Base Reservoir (m)	Single	-50	-50	-50	-50
Oil-Water Contact (mTVDSS)	Lognormal	940	998	1060	999
Area Uncertainty (%)	Normal	95	100	105	100
Degree of Fill (%)	Single	100	100	100	100
Net to Gross (%)	Normal	50	60	70	60
Porosity (PHIE) (%)	Normal	18	19	20	19
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.1	1.13	1.15	1.13
GOR (scf/bbl)	Normal	100	110	120	110
Oil Recovery Factor (%)	Normal	20	27.5	35	27.5

Table 5-12: Summary of Input Parameters for Golspie (Jurassic) Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}	Mean
Thickness (m)	Normal	300	400	500	400
Shift Top Reservoir (%)	Single	25	25	25	25
Area Uncertainty (%)	Normal	95	100	105	100
Oil-Water Contact (mTVDSS)	Lognormal	1060	1099	1140	1100
Net to Gross (%)	Normal	85	87.5	90	87.5
Porosity (PHIE) (%)	Normal	15	16.5	18	16.5
Water Saturation (%)	Normal	15	25	35	25
Formation Volume Factor (v/v)	Normal	1.1	1.13	1.15	1.13
GOR (scf/bbl)	Normal	100	110	120	110
Oil Recovery Factor (%)	Normal	20	27.5	35	27.5

Table 5-13: Summary of Input Parameters for Golspie (Triassic) Volumetrics

	STOIIP (MMstb)			
	Low	Best	High	Mean
Jurassic	14	47	95	52
Triassic	28	74	150	83

Table 5-14: Gross STOIIP for Golspie

5.3.4.1 Risking

In assessing the Geological Probability of Success (Pg %) we have reviewed the prospects in the context of the basin (Play Pg) and the prospect specific area (Prospect Pg), using the data available and our experience in the North Sea. The risking has been carried out in accordance with the RPS Energy guidelines.

The chance of success assigned to each of the prospects is shown for the Jurassic in Table 5-15 and for the Triassic in Table 5-16.

JURASSIC	Play Pg %				Prospect Pg %					DHI[1]	
	Reservoir	Seal	Source	Play Total	Trap	Seal	Reservoir	Charge	Prospect Total	+/- %	Total[2]
Dunrobin West	100	100	100	100	76	48	95	90	31	+3	34
Dunrobin Central and East	100	100	100	100	76	48	95	90	31	0	31
Golspie	100	100	100	100	90	36	95	95	29	-2	27

[1] DHI score is added or subtracted from overall Pg
[2] Total Pg = Play Pg x Prospect Pg + DHI score
Pg comprises the chance of recovering a significant volume of hydrocarbons to surface from within the defined prospect area

Table 5-15: Geological Probability of Success (Pg%) for Jurassic Targets

TRIASSIC	Play Pg %				Prospect Pg %					DHI[1]	
	Reservoir	Seal	Source	Play Total	Trap	Seal	Reservoir	Charge	Prospect Total	+/- %	Total[2]
Dunrobin West	76	64	100	48	76	40	90	90	25	0	12
Dunrobin Central and East	76	64	100	48	76	48	90	90	29	0	14
Golspie	76	64	100	48	90	32	90	95	25	0	12

[1] DHI score is added or subtracted from overall Pg
[2] Total Pg = Play Pg x Prospect Pg + DHI score
Pg comprises the chance of recovering a significant volume of hydrocarbons to surface from within the defined prospect area

Table 5-16: Geological Probability of Success (Pg%) for Triassic Targets

Play Risk

For the Jurassic reservoirs the play can be regarded as proven, since the nearby Beatrice field has shown that all of the elements required for the play are present within the basin segment being assessed for P2478. Additionally, oil has been proven in the Jurassic of the 12/27-1, 12/27-2 and 11/30-6 wells which lie at the border of the licence.

For the Triassic reservoirs we have applied a Play Pg of 48%, since this play is not proven within the basin. At least seven wells have penetrated the Triassic section within the vicinity of the P2478 licence and demonstrate a consistently high net sand interval over 200m thick, however, no wells have encountered any oil or gas in these reservoirs. We believe the highest risk for this play is the presence of a suitable top seal (separating it from the overlying Jurassic reservoirs) and the quality of the sands to perform as a productive reservoir.

Prospect Risk

For the prospect risk we have assessed each prospect against the same criteria for Trap, Seal, Reservoir and Charge.

The key risks identified for the P2478 prospects are related to Trap and Seal. Given the shallow nature of the prospects (particularly the Dunrobin structures) there is a high risk that the top seal has been breached through a lack of mechanical strength, throughgoing faulting or fault juxtaposition against thief zones in the hanging wall. We view the top seal risk to be slightly higher in the Golspie Prospect since the overlying Heather and Kimmeridge formations are both sand prone in the nearby 12/27-1 well.

These risks are compounded by an uncertainty on the early deformation and charge history of the prospects, since it is possible that any early oil charge (an associated pressures) may have compromised top seal following trap uplift during the Tertiary.

DHI Score

For prospects where a Direct Hydrocarbon Indicator (DHI) is observed, such as a flat spot, amplitude conformance with structure or change in polarity across a potential contact, a positive score has been assigned to uplift the overall Pg %. By using this approach, we first assess the prospect on its geological merits before considering the DHI.

Where we are confident that we should see a DHI, but none are observed, then we may apply a negative score to downgrade the overall Pg %.

The scores are determined qualitatively by assessing the data quality (is the data quality sufficient to observe a DHI or could it be an artefact?), the likelihood of a DHI to be observed given the expected fluid and rock properties, and the chance that the DHI maybe a paleo effect (such as a preserved porosity effect or low saturation gas).

In the case of Dunrobin West, we have observed an increasingly negative acoustic impedance (amplitude) at the Top Beatrice horizon up dip near the crest of the closure. This amplitude anomaly appears to conform to the structural contours at a similar TWT and depth level. There is also an observed AVO between the near and far stacks. Based on the fluid substitution work completed on the 12/27-1 and 12/26c-5 wells (section 5.3.3.1) we believe this could be due to the presence of a gas cap. However, there is a residual possibility that the anomaly maybe caused by low saturation gas or a paleo porosity preservation effect. A DHI uplift of 3% has been applied for this prospect.

For the Dunrobin Central and East Prospect, whilst we observe a general increase in acoustic impedance across the structure, there is less conformance with structure. Additionally, the amplitude anomaly is consistent with a thinning isochore, and it is possible that the anomaly is due to seismic tuning and/or a change in porosity on structure. No DHI uplift or reduction has been applied for this prospect since it is ambiguous.

For the Golspie Prospect, we do not observe any change in the acoustic impedance within the closure area. There are no signs of any DHI. Based on the observations at the Dunrobin structures, and the fluid substitution work carried out by RPS we have concluded that the lack of DHI could mean either a negligible thickness of pay (e.g. 12/27-1 well) or an absence of pay all together. A negative DHI score of -2% has been applied to this prospect.

5.3.5 Reservoir Engineering Assessment

Reservoir engineering data is limited on the P2478 assets. Likely recovery factors have therefore been estimated based on analytical modelling, focussing on the data available which suggests a viscous oil. Due to the shallow depth of the Dunrobin accumulations, it is anticipated that the reservoir temperature will be approximately 18-20 °C at current setting. The API and corresponding viscosity could be highly variable due to active charge vs ongoing biodegradation.

RPS has therefore considered two fluids to form the low and high case:

- Low Case:
  - based on tested fluid at 12/27-1 well and Beatrice field
  - 20 °API oil
  - 24 °C pour point
  - 300 cP viscosity
- High Case:
  - based on tested fluid at 11/30-6 well
  - 37 °API oil
  - -2 °C pour point
  - 50 cP viscosity

Fluid Formation Volume Factors (FVF) have been estimated based on correlations. Gas FVF has been estimated using the Dranchuk et al formulation of the Standing and Katz correlation[20]. Oil FVF is estimated using the Vasquez and Beggs correlation[21]. Low and High values for each FVF were obtained by using a range of inputs to the correlations representing the uncertainty range as shown in Table 5-17.

	Low	High
Reservoir Pressure (psia)	570	825
Bubble Point Pressure (psia)	496	513
API	20	37
GOR (scf/stb)[1]	111	111
Temperature (°F)	57.2	68
Gas specific gravity	0.65	0.7
Separator Temp (°F)	60	
Separator Pressure (psia)	14.7	
Oil FVF (rb/stb)	1.050	1.057
Gas FVF (rcf/scf)	0.014	0.023

1 Estimated from Beatrice GOR

Table 5-17: Estimated Input Ranges to FVF Correlations and Corresponding Outputs

[20] Dranchuk, P. M., Purvis, R. A., and Robinson, D. B., "Computer Calculations of Natural Gas Compressibility Factors Using the Standing and Katz Correlation," Institute of Petroleum Technical Series, No. IP 74-008,1974.

[21] Vasquez, M., and Beggs, H. D., "Correlations for Fluid Physical Property Predictions," Journal of Petroleum Technology, June 1980, pp. 968-970

Due to the oil viscosities assumed, a Buckley-Leverett calculation was done assuming each of the viscosities described above. The fractional flow model allows calculation of the cumulative recovery factor as a function of the fractional flow (Figure 5.30, Figure 5.31).

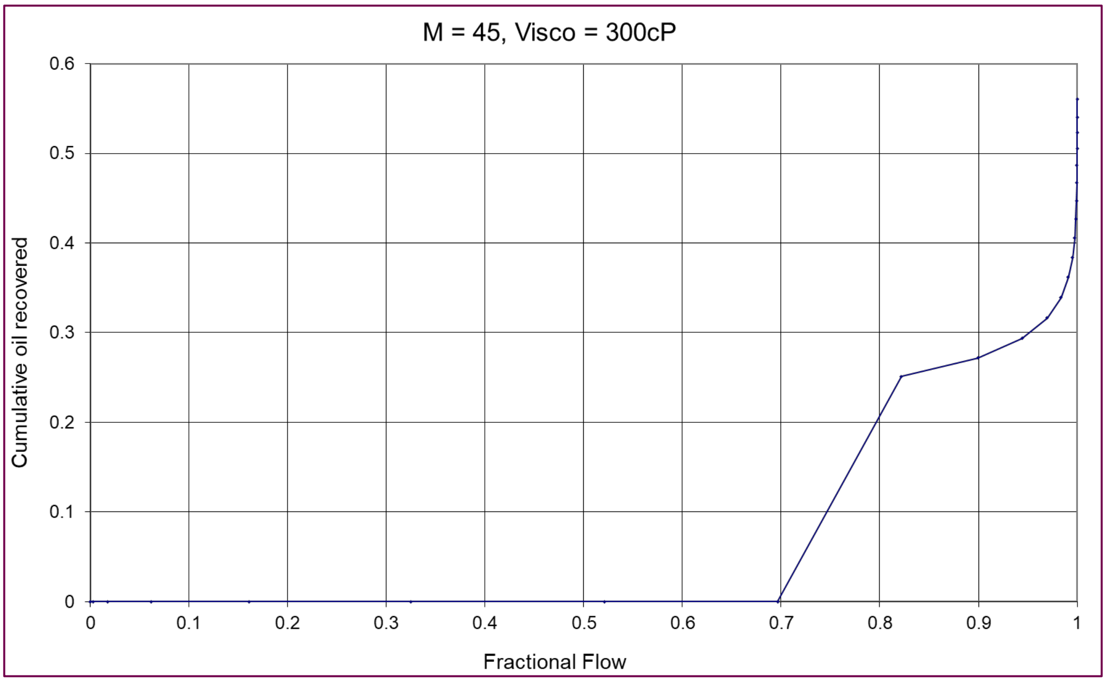


Figure 5.30: Buckley-Leverett Fractional Flow for 300 cP Oil and a Corresponding Mobility Ratio of 45

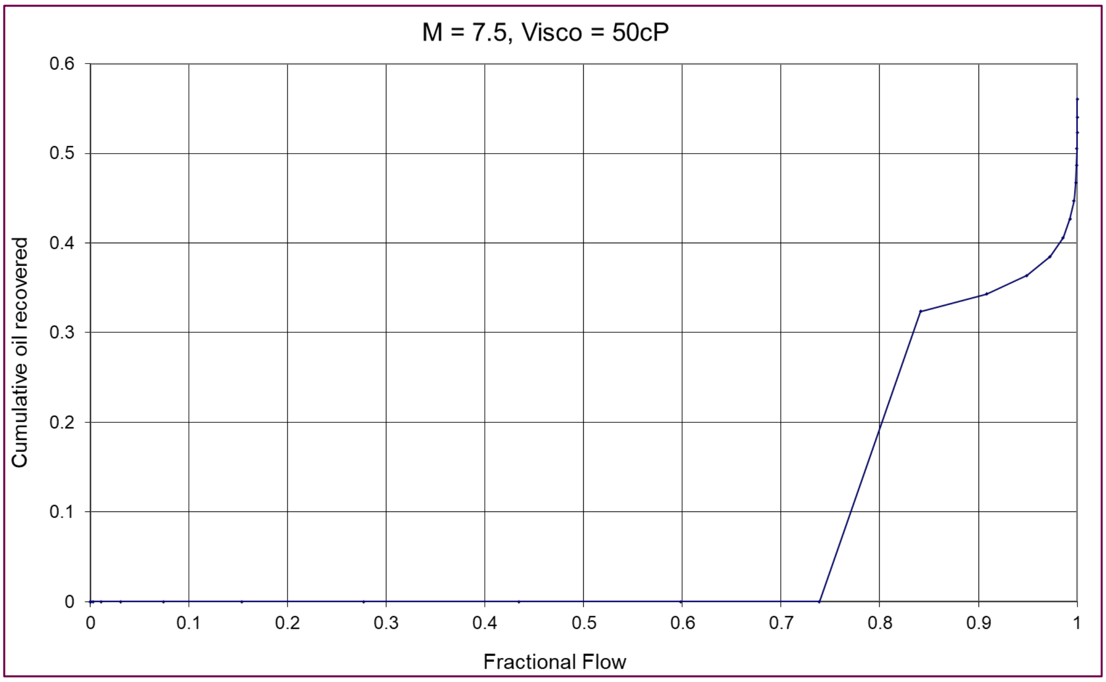


Figure 5.31: Buckley-Leverett Fractional Flow for 50 cP Oil and a Corresponding Mobility Ratio of 7.5

This analytical model gives an ideal recovery factor, at 90% water cut, of 34% and 27% for 50 cP oil and 300 cP oil, respectively. These figures then require further adjustment for sweep efficiency, assuming 55% in the low case, and 90% in the high case gives the recovery factors for Dunrobin as shown in Table 5-18. As Golspie is deeper than Dunrobin, and is likely to have a lower viscosity, it is anticipated that the recovery factors will be higher, as reflected in the table below.

	Recovery factor	
	Low	High
Dunrobin	15%	30%
Golspie	20%	35%

Table 5-18: Estimated Recovery Factor Range for P2478 Assets

5.4 Surface (Wells and Facilities) Review

5.4.1 Dunrobin/Dunrobin West FPSO

Dunrobin is currently an undrilled oil prospect in the UK North Sea consisting of the Dunrobin Central and East and Dunrobin West. Reabold have proposed a leased FPSO with subsea wells as the development concept for Dunrobin West. Associated gas to be used for fuel with excess re-injected into the reservoir. In potential upside cases gas export to the nearby Captain Field may be economically viable but has not been considered here. Subsea production wells will be fitted with downhole ESPs routed to a redeployed existing FPSO, potentially a Sevan (cylindrical hull shape) style vessel.

The crude expected in Dunrobin is potentially partially degraded due to low reservoir depth and may be of low API or waxy. Similar crudes have been developed in the UK North Sea, but flow assurance issues may arise which may require more costly facilities than have been assumed by Reabold.

RPS is supportive of the concept presented by Reabold.

Reabold now run with P50 economics and an increased cost estimate reflecting the current or updated P50 resource of 42 mmbbl.

Reabold have presented a cost estimate for Dunrobin West P50 which has been reviewed by RPS. The Reabold CAPEX cost estimate is given in Table 5-19 below:

	Total (£MM)
Exploration Well	8.6
Appraisal Well / ST / DST	25.5
Project Management / Surveys	10.5
FEED / Engineering	7
FPSO Refurb	52
Subsea & FPSO Installation	110
6 Producers & 3 Injectors	153
Contingency	40
Total	406.6
Abandonment Provision	80

Table 5-19: Reabold CAPEX Estimate: Dunrobin West FPSO

RPS has reviewed the costs provided by Reabold for the Dunrobin West development and have the following comments:

- £110m appears adequate for the subsea facilities.
- £52m for the FPSO refurbishment should allow for a reasonable level of work and in RPS; opinion is a reasonable allowance. It is accepted that this assumption carries a significant uncertainty and will be dependent on the vessel identified and the work scope required.
- The well costs appear reasonable, the Dunrobin reservoir is shallow so the wells will be short duration drilling time.
- Abandonment provision is reasonable.
- Reabold has estimated the FPSO lease and O&M cost as £38m/year (approximately $130,000/day) which RPS view as reasonable. Reabold has additionally allowed for the vessel owner to receive a tariff equivalent to 7.14% of revenue (equates to $5/bbl at assumed crude price of $70/bbl). RPS view this as reasonable but with a caveat that as Dunrobin is expected to be a partially degraded crude with the potential to trade at a discount to Brent. RPS would recommend sensitivities on crude discounts during valuation work.
- Power generation has been assumed to be powered from the associated gas. It is likely that the facility could become gas deficient towards the end of field life where the amount of associated gas available is insufficient for power generation. Additional OPEX should be considered to mitigate this from either importing electrical power form a nearby facility/wind farm or a switch to diesel power generation. No allowances have been made by RPS for this. There is potential for additional gas resource in the gas cap which could be used for fuel (Reabold estimate 12 Bscf)
- In RPS's opinion the contingency is too low.

The development contingency assumed by Reabold is the equivalent of 10.9% of the total project CAPEX (Contingency allowance of £40m in a total CAPEX excluding contingency of £366m). In RPS' opinion this is too low given the undefined state that Dunrobin still requires further appraisal drilling. Most operators in the oil and gas industry use the AACE (Association for the Advancement of Cost Engineering) classes. Dunrobin would be a Class 4/5 estimate at this stage which would usually be associated with a contingency allowance of 25-30%.

Class	Level of Definition	Usage	Methodology	Accuracy Range	Contingency
5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgement, or Analogy	L: -20% to -50% H: +30% to 1000%	30%
4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	25%
3	10% to 40%	Budget, Authorisation, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	15%
2	30% to 70%	Control or Bid/Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	10%
1	50% to 1000%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5%

Table 5-20: AACE Cost Estimate Classification & Contingency

The development schedule assumed by Reabold has been inferred from their cost estimate profile, this is shown in Table 5-21: Reabold Dunrobin Schedule.

Capex	2023	2024	2025	2026	2027	2028	2029
Drill Exploration Well	0.2	8.4					
Appraisal Well / ST / DST		0.5	25.0				
Project Management / Surveys		0.5	1.0	3.0	4.0	2.0	
FEED / Engineering		1.0	2.0	3.0	1.0		
FPSO Refurb				2.0	50.0		
Subsea & FPSO Installation					20.0	90.0	
6 Producers & 3 Injectors					75.0	78.0	
Contingency		1.0	4.0		15.0	20.0	
Total Capex £MM	**0.2**	**11.4**	**32.0**	**8.0**	**165.0**	**190.0**	**0.0**

Table 5-21: Reabold Dunrobin Schedule

In RPS' opinion the schedule achievable but aggressive. Exploration well drilling in 2024 will require well planning to commence in 2023. Appraisal drilling the following year is aggressive and may not allow sufficient time to analyse and understand fully the exploration well results before commencing appraisal well planning. A sensitivity of an additional year to reach FID and first production would be recommended for valuation purposes.

5.4.2 Golspie

Golspie is an undrilled Jurassic oil prospect to the west of the Dunrobin prospect.

Reabold has considered a development consisting of subsea wells tied to a leased redeployed FPSO similar to that assumed for Dunrobin. Due to the similarity with the concept presented by Reabold for Dunrobin, RPS are supportive of the concept for Golspie. In the event of exploration and appraisal success at Dunrobin, Dunrobin West and Golspie, a joint development may be the optimal solution, but this has not been considered further at this time by RPS.

Reabold has presented the following cost estimate for Golspie Pmean (Table 5-22).

	Total (£MM)
Exploration Well	12.2
Project Management / Surveys	7.5
FEED / Engineering	4
FPSO Refurb	11
Subsea & FPSO Installation	40
2 Producers & 2 Injectors	68
Contingency	16
Total	158.7
Abandonment Provision	35

Table 5-22: Reabold CAPEX Estimate: Golspie

RPS have reviewed the costs provided by Reabold for the Golspie development and have the following comments:

- £40m appears too low for the subsea facilities.

- £11m for the FPSO refurbishment should allow for a reasonable level of work and in RPS; opinion is a reasonable allowance. It is accepted that this assumption carries a significant uncertainty and will be dependent on the vessel identified and the work scope required.

- The well costs appear reasonable, the Dunrobin West reservoir is shallow so the wells will be short duration drilling time.

- Abandonment provision is reasonable.

- In RPS's opinion the contingency is too low.

- Reabold has estimated the FPSO lease and O&M cost as £30m/year (approximately $103,000/day) which RPS view as reasonable. Reabold has additionally allowed for the vessel owner to receive a tariff equivalent to 7% of revenue (equates to $4.9/bbl at assumed crude price of $70/bbl) plus an additional $2/bbl transportation tariff. RPS view this as reasonable but with a caveat that as Golspie is expected to be a partially degraded crude it is likely to trade at a discount to Brent. RPS would recommend sensitivities on crude discounts during valuation work.

- Power generation has been assumed to be powered from the associated gas. It is likely that the facility could become gas deficient towards the end of field life where the amount of associated gas available is insufficient for power generation. Additional OPEX should be considered to mitigate this from either importing electrical power form a nearby facility/wind farm or a switch to diesel power generation. No allowances have been made by RPS for this.

The development contingency assumed by Reabold is the equivalent of 11.2% of the total project CAPEX (Contingency allowance of £16m in a total CAPEX excluding contingency of £142.7m). In RPS' opinion this is too low given the undefined state of Golspie is still an undrilled prospect. Most operators in the oil & gas industry use the AACE classes. Dunrobin would be a Class 4/5 estimate at this stage which would usually be associated with a contingency allowance of 25-30%

The development schedule assumed by Reabold has been inferred from their cost estimate profile, this is shown in Table 5-23.

Capex	2023	2024	2025	2026	2027	2028
Drill and Test Exploration Well	0.2	12.0				
Project Management		0.5	3.0	3.0	1.0	
FEED / Engineering			2.0	2.0		
FPSO Procurement / Refurb			1.0	10.0		
Subsea & FPSO Installation				10.0	30.0	
2 Producers & 2 Injectors (Gas / Water)				34.0	34.0	
Contingency		1.0		5.0	10.0	
Total Capex £MM	**0.2**	**13.5**	**6.0**	**64.0**	**75.0**	**0.0**

Table 5-23: Reabold Golspie Development Schedule

In RPS' opinion the schedule is too aggressive and unlikely to be achievable. Exploration well drilling in 2024 will require well planning to commence in 2023. Reabold assume that the Golspie field can be fully appraised from a single exploration well with no allowance for testing or sidetrack.

5.5 Reserves and Resources

In-place volumetric ranges (Table 5-7, Table 5-8, Table 5-11, Table 5-14) have been combined stochastically with ranges of recovery factor (Table 5-18). Resultant volumes and associated geological risk are tabulated in Table 5-24, Table 5-25, Table 5-26 and Table 5-27.

SUMMARY OF OIL PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES As of 30th September 2022[6]									
	Gross Prospective Resources (Unrisked)[1,4] (MMstb)				Reabold Net Prospective Resources (Unrisked)[2, 3, 4] (MMstb)				Pg (%)
	1U	2U	3U	Mean[5]	1U	2U	3U	Mean[5]	
Dunrobin West									
Jurassic	7	42	168	71	2	15	60	25	34
Triassic	7	34	98	45	2	12	35	16	12
Dunrobin Central and East									
Jurassic	1	8	67	22	0.4	3	24	8	31
Triassic	1	9	56	22	0.4	3	20	8	14
Golspie									
Jurassic	4	12	27	14	1	4	10	5	27
Triassic	7	20	43	23	3	7	15	8	12

Notes:

*1.Gross field Resources (100% basis) **before** economic limit test*

*2 Companies working interest share of net field Resources **before** economic limit test*

3. Reabold net working interest is 36%

*4. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

5. Mean is defined as the arithmetic average of successful outcomes

6. Aligned with effective date of primary CPR.

Table 5-24: Oil Prospective Technically Recoverable Resources as of 30th September 2022

SUMMARY OF OIL PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES As of 30th September 2022[5]	Upland Resources Net Prospective Resources (Unrisked)[1, 2, 3,] (MMstb)				Baron Oil Net Prospective Resources (Unrisked)[1, 2, 3,] (MMstb)				Pg (%)
	1U	2U	3U	Mean[4]	1U	2U	3U	Mean[4]	
Dunrobin West									
Jurassic	2	13	54	23	2	13	54	23	34
Triassic	2	11	31	15	2	11	31	15	12
Dunrobin Central and East									
Jurassic	0.4	2	21	7	0.4	2	21	7	31
Triassic	0.3	3	18	7	0.3	3	18	7	14
Golspie									
Jurassic	1	4	9	5	1	4	9	5	27
Triassic	2	6	14	7	2	6	14	7	12

Notes:
*1 Companies working interest share of net field Resources **before** economic limit test*
2. Upland Resources and Baron Oil net working interest is 32%
*3. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*
4. Mean is defined as the arithmetic average of successful outcomes
5. Aligned with effective date of primary CPR.

Table 5-25: Oil Prospective Technically Recoverable Resources as of 30th September 2022 – JV Partners

SUMMARY OF GAS PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES
As of 30th September 2022[7]

	Gross Prospective Resources (Unrisked)[1,5] (Bscf)				Reabold Net Prospective Resources (Unrisked)[3, 4, 5] (Bscf)				Pg (%)
	1U	2U	3U	Mean[6]	1U	2U	3U	Mean[6]	
Dunrobin West									
Jurassic[2]	2	7	22	10	0.9	3	8	4	34
Triassic	1	4	11	5	0.3	1	4	2	12
Dunrobin Central and East									
Jurassic	0.1	1	7	2	0.04	0.3	3	1	31
Triassic	0.1	1	6	2	0.04	0.4	2	1	14
Golspie									
Jurassic	0.4	1	3	2	0.1	0.5	1.1	0.6	27
Triassic	0.8	2	5	3	0.3	0.8	1.7	1.0	12

Notes:

*1.Gross field Resources (100% basis) **before** economic limit test*

*2.Includes a mix of associated gas and non-associated gas from Dunrobin West Gas Cap, all others are associated gas **only***

*3.Companies working interest share of net field Resources **before** economic limit test*

4.Reabold net working interest is 36%

*5. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

6. Mean is defined as the arithmetic average of successful outcomes

7. Aligned with effective date of primary CPR

Table 5-26: Gas Prospective Technically Recoverable Resources as of 30th September 2022

SUMMARY OF GAS PROSPECTIVE TECHNICALLY RECOVERABLE RESOURCES
As of 30th September 2022[5]

	Upland Resources Net Prospective Resources (Unrisked) [2, 3, 4] (Bscf)				Baron Oil Net Prospective Resources (Unrisked) [2, 3, 4] (Bscf)				Pg (%)
	1U	2U	3U	Mean[5]	1U	2U	3U	Mean[5]	
Dunrobin West									
Jurassic[1]	0.8	2	7	3	0.8	2	7	3	34
Triassic	0.2	1	3	2	0.2	1	3	2	12
Dunrobin Central and East									
Jurassic	0.04	0.3	2	1	0.04	0.3	2	1	31
Triassic	0.03	0.3	2	1	0.03	0.3	2	1	14
Golspie									
Jurassic	0.1	0.4	1.0	0.5	0.1	0.4	1.0	0.5	27
Triassic	0.3	0.7	1.5	0.9	0.3	0.7	1.5	0.9	12

Notes:

*1.Includes a mix of associated gas and non-associated gas from Dunrobin West Gas Cap, all others are associated gas **only***

*2.Companies working interest share of net field Resources **before** economic limit test*

3. Upland Resources and Baron Oil net working interest is 32%

*4. The volumes are presented for each reservoir and, at the client request, have **not** been aggregated.*

5. Mean is defined as the arithmetic average of successful outcomes

6. Aligned with effective date of primary CPR

Table 5-27: Gas Prospective Technically Recoverable Resources as of 30th September 2022 – JV Partners

6 CONSULTANT'S INFORMATION

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Resources are based on data provided by Reabold. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents RPS' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Reabold and named Third Parties and their corporate advisors. The provision of professional services has been solely on a fee basis.

To the best of our knowledge, no conflict of interest has existed in the work conducted as part of this report. Furthermore, RPS nor any of the management and employees involved in the work have any interest in the assets evaluated or related to the analysis carried out as part of this report.

Table 6-1 provides a summary of staff involved in this evaluation, their level of experience and professional qualifications.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Eleanor Rollett	Project Manager	>20	BSc. Honours 1st Class Geology, Glasgow University (1986-1990) Postgraduate Diploma Information Technology with Distinction, Open University (2002)	EAGE Geological Society – Chartered Geologist and Fellow
Ben Lowden	Petrophysics Lead	>20	BSc Honours Geology and Oceanography, University of Southwest (1983-1986) MSc in Sedimentology, Reading University (1987-1988) PhD Geological Engineering, Imperial College (1988-1991)	Society of Professional Well Log Analysts
David Walker	Cost/Facilties Lead	>20	MEng Hons, Chemical Process Eng, University of Sheffield	
Owain Jackson	Gesocience Lead	>20	MSci. Geology University of Southampton (1996-2000)	Fellow Geological Society of London, AAPG
Adam Turner	Reservoir Engineering Lead	>10	BEng Chemical Engineering, University of Bath, MSc Petroleum Engineering, Heriott Watt University	Society of Petroleum Engineers, Institute of Chemical Engineers, Energy Institute
Conall Cromie	Technical Assistant	3	Qualifications: BSc Geology, Royal Holloway, University of London (2016-2019). MSc Petroleum Geoscience, Royal Holloway, University of London (2019-2020).	Geoscience Energy Society of Great Britain

Table 6-1: Summary of Consultant Personnel

Appendix A
Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level

GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GPoS	Geological Probability of Success
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package

petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars
t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar

VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.1.1 Petroleum Resources Classification Framework

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

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

Figure A.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

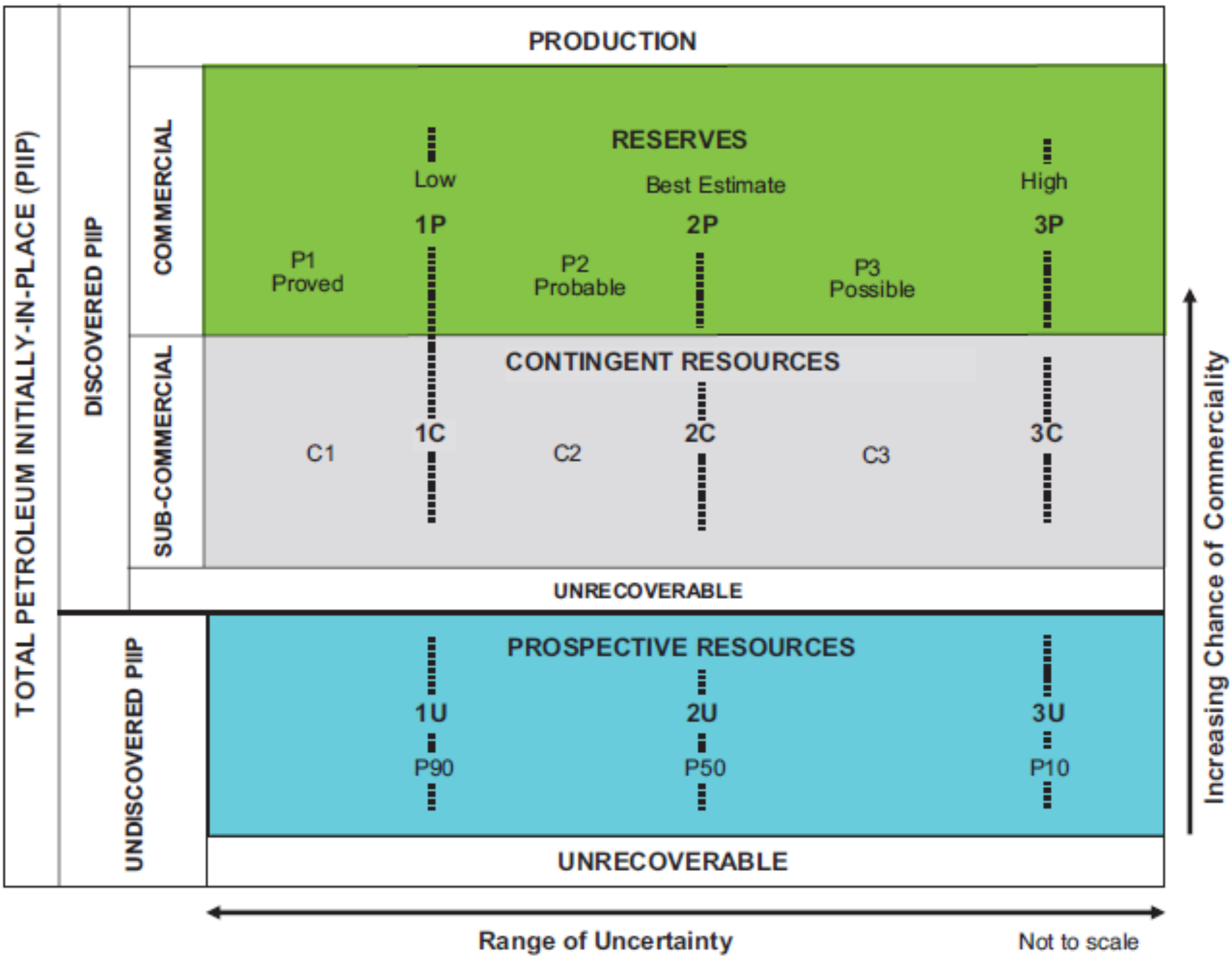


Figure A.1: Resources classification framework

The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

- **Total Petroleum Initially-In-Place (PIIP)** is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

- **Production** is the cumulative quantities of petroleum that have 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 (see PRMS 2018 Section 3.2, Production Measurement).

Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective 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 satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

  Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

  Reserves are further categorized in accordance with the range of uncertainty and should 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, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. 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 range of uncertainty associated with the estimates and should be sub- classified based on project maturity and/or economic status.

- **Undiscovered PIIP** 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 geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

- **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

Other terms used in resource assessments include the following:

- **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

- **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.1.2 Project Based Resource Evaluations

The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure A.2).

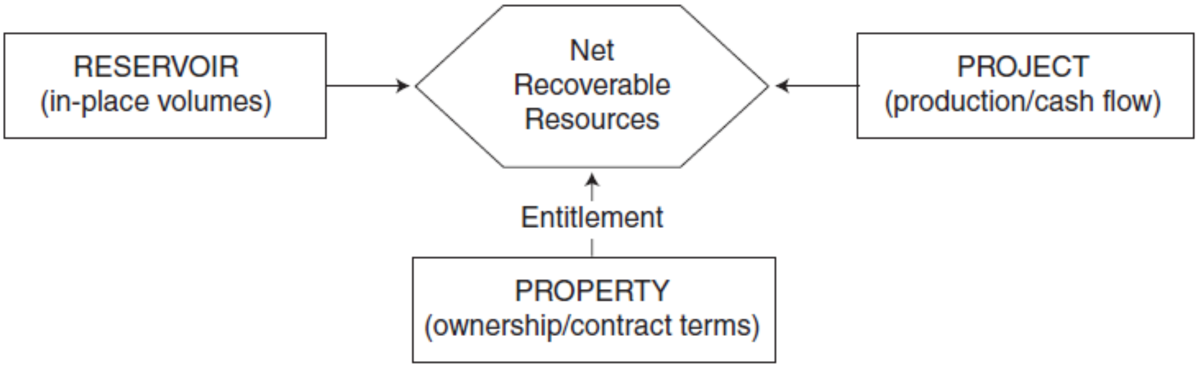


Figure A.2: Resources Evaluation

The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty.

The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See PRMS 2018 Section 2.1.3.5, Project Maturity Sub-

Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

B.2 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure A.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.2.1 Resources Classification

The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

B.2.1.1 Determination of Discovery Status

A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see PRMS 2018 Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

B.2.1.2 Determination of Commerciality

Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section A.2.1.2. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and 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 five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

B.2.1.3 Project Status and Chance of Commerciality

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 qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure A.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.
- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

B.2.1.3.1 Project Maturity Sub-classes

As Figure A.3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

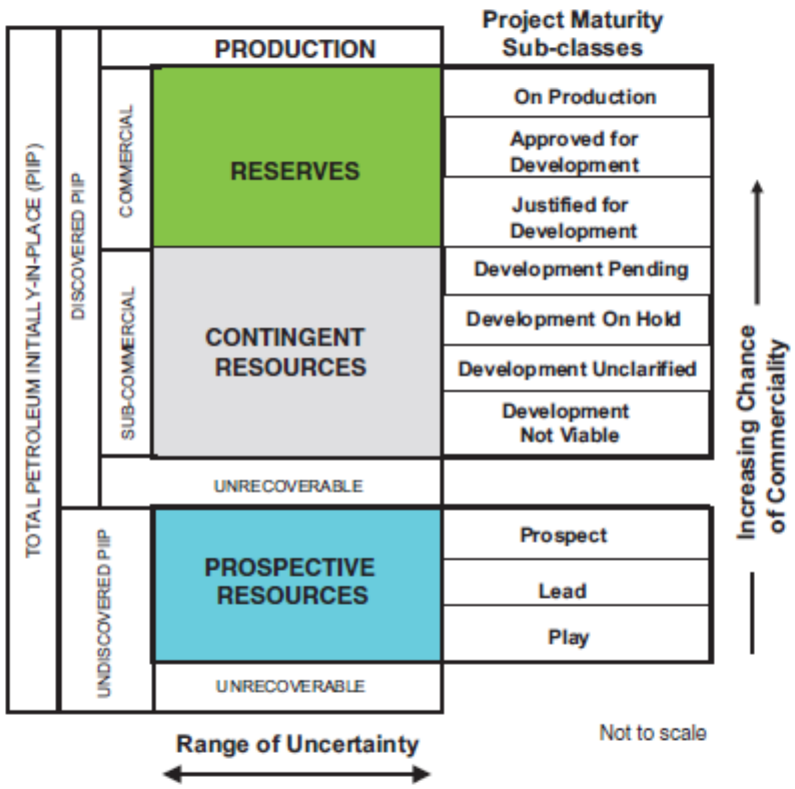


Figure A.3: Sub-classes based on project maturity

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in Section A.2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure A.3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

B.2.1.3.2 Reserves Status

Once projects satisfy commercial maturity (criteria given in PRMS 2018 Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
  - **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the "minor costs to access" Developed Non-Producing Reserves and the "significant investment" needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section A.2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

B.2.1.3.3 Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section A.2.1.2.

- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section A.2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.2.2 Resources Categorization

The horizontal axis in the resources classification in Figure A.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).

- The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

- Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as "split classification."

B.2.2.1 Range of Uncertainty

Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section A.2.2.2, Category Definitions and Guidelines).

Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure A.1 and Figure A.3) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

- Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. 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.

- 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.

- Possible Reserves are those additional Reserves that 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) Reserves, 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 that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.2.3 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure A.1), with preference for applying project maturity sub-classes (Figure A.3). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section A.2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.2.3.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section A.2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.2.4 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

- Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also PRMS 2018 Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers

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