P6059 SundaGas

Competent Person's Report on the Contingent and Certain Prospective Resources in Timor-Leste TL-SO-19-16 ("Chuditch") PSC

Prepared For: Baron Oil Plc

By: ERCE

Date: February 2023

ERCE
Independent Energy Experts

Approved by: Adam Law

Date released to client: 27 February 2023

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27 February 2023
The Directors
Baron Oil Plc
Finsgate
5-7 Cranwood Street
London, EC1V 9EE

Dear Sirs,

Re: Competent Person's Report – TL-SO-19-16, Timor-Leste, PSC

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a Competent Person's Report ("CPR") for certain Contingent and Prospective Resources held by SundaGas Banda Unipessoal Lda ("SundaGas"), a subsidiary of Baron Oil Plc ("Baron Oil"), within the TL-SO-19-16 PLC offshore Timor-Leste.

The effective date ("Effective Date") of this report is 31st January 2023. For the preparation of this CPR ERCE was provided with data and information by SundaGas up to 31st January 2023.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/ SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 4 of the report. The full text can be downloaded from:-

https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Nomenclature that may be used in this CPR and the enclosed report is summarised in Appendix 3: Nomenclature.

Use of the Report

This CPR is produced solely for the benefit of and on the instructions of Baron Oil, and not for the benefit of any third party. Any third party to whom the client discloses or makes available this report shall not be entitled to rely on it or any part of it.

Baron Oil agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and Baron Oil shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE. In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by ERCE to the client.

Disclaimer

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by SundaGas was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this CPR.

The accuracy of any Contingent Resources and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While Contingent Resources and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

In the case of Contingent Resources presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

In the case of the undiscovered resources (Prospective Resources) presented in this report, there is no certainty that any resources will be discovered, and for any discovery there is no certainty it will be commercially viable to produce any portion of the resources.

No site visits were undertaken in the preparation of this CPR.

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in Baron Oil or SundaGas. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of the Company, its directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work undertaken and preparation of this Report has been supervised by Dr Adam Law, Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society, and a member of the Society of Petroleum Evaluation Engineers.

Yours faithfully,

Dr Adam Law

Director, ERCE

1. Summary

1.1. Introduction

SundaGas Banda Unipessoal Lda. ("SundaGas"), a wholly owned subsidiary of Baron Oil Plc ("Baron Oil"), is the operator of the Chuditch PSC and holds a 75% effective interest.

Table 1.1: SundaGas licence interest

Country	Block	Working Interest	Licence Expiry	Field(s)
Timor-Leste	TL-SO-19-16	75.00%	18 June 2028	Chuditch

Notes

1. The 7 year contract exploration period is scheduled to end 18 June 2028. There is a 25 year production phase to 18 June 2053.

The Chuditch discovery was made in 1998 with the drilling of Well Chuditch-1 by Shell. ERCE has independently assessed the Hydrocarbons Initially In Place (HIIP) and Contingent Resources for the Chuditch-1 discovery. In addition, ERCE has independently assessed the HIIP, Prospective Resources and geological Chance of Success (COS) for four surrounding prospects (Chuditch NE, Chuditch SW Alpha, Chuditch SW Beta and Quokka).

ERCE has carried out this work using the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and determined the range of petroleum initially in place. We have prepared estimates of recovery factors based on consideration of the results of reservoir simulation models, classical reservoir engineering calculations and the performances of analogue fields. We have derived independent estimates of contingent and prospective resources of gas and condensate.

Economic evaluation has not been done as part of this CPR and hence is not presented. The Chuditch-1 discovery is at an early stage of development planning. ERCE has reviewed, at a high level, the development options for the Chuditch-1 discovery.

ERCE has reviewed data made available through to 31 January 2023 and the effective date of this report is 31 January 2023. SundaGas has confirmed to ERCE that there have been no material changes with respect to the properties addressed subsequent to 31 January 2023 and the date of this report.

1.2. Methodology

ERCE has relied upon data and information made available by SundaGas in the preparation of this report. These data comprise details of SundaGas licence interest, seismic data (mainly as section images), basic exploration and engineering data (including well logs, core, PVT and MDT pre-test data), technical reports, interpreted data, and the field development plans.

We have carried out a review of seismic data, regional and analogue geological data, petrophysical data, reservoir engineering data and prepared independent estimates of hydrocarbons initially in place. Subsequently, we have derived independent gas and condensate estimates of Contingent Resources for the Chuditch Main discovery and Prospective Resources in surrounding prospects. ERCE has estimated Geological Chance of Success (COS) for each prospect.

In estimating petroleum in place and recoverable, we have used standard techniques of petroleum engineering. These techniques combine geophysical and geological knowledge with detailed information concerning porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty to calculate the range of petroleum initially in place and recoverable volumes.

In the case of the undiscovered resources (Prospective Resources) presented in this report, there is no certainty that any resources will be discovered, and for any discovery there is no certainty it will be commercially viable to produce any portion of the resources.

No site visit was undertaken in the preparation of this report.

1.3. Summary and Results

ERCE's estimates of Contingent Resources for gas and condensate for the Chuditch-1 discovery are summarised in Table 1.2 and Table 1.3, both gross on-block and net working interest to SundaGas. ERCE attributes the Contingent Resources associated with the Chuditch-1 discovery to the sub-class Development Unclarified. The Chuditch discovery Development Unclarified Contingent Resources are contingent on the drilling and testing of an appraisal well, the Operator finalising a commercially viable development plan and the Operator being able to fund and execute this development plan, including obtaining partner and regulatory consents to the appropriate facilities.

Table 1.4 and Table 1.5 summarise ERCE's estimates of Prospective Resources for gas and condensate, both gross on-block and net working interest to SundaGas.

Table 1.2: Gross On-block Contingent Resources

Discovery	Gross On-block Gas Contingent Resources (Bscf)				Gross On-block Condensate Contingent Resources (MMstb)			
	1C	2C	3C	Mean	1C	2C	3C	Mean
Chuditch-1	461	929	1845	1084	1.4	4.1	11.9	5.9

Table 1.3: Net Working Interest Contingent Resources

Discovery	SundaGas Working Interest	Net Working Interest Gas Contingent Resources (Bscf)				Net Working Interest Condensate Contingent Resources (MMstb)			
		1C	2C	3C	Mean	1C	2C	3C	Mean
Chuditch-1	75%	346	697	1383	813	1.1	3.1	9.0	4.4

Notes

1. Gross On-block Contingent Resources are limited to within PSC TL-SO-19-16 and are based on percentage on-block x total Gross Contingent Resources.
2. Company working interest is based on a SundaGas working interest of 75.00 percent following development and first gas. SundaGas are carrying the remaining 25.00 percent interest to development.
3. Company Net Working Interest Contingent Resources are based on the working interest share of the field post development x Gross On-block Contingent Resources and are prior to deduction of royalties.
4. Company net entitlement Contingent Resources require a full economic evaluation which has not been done as part of this CPR and hence are not presented.
5. These are unrisked Contingent Resources that have not been risked for chance of development and are sub-classified as Development Unclarified.
6. There is no certainty that it will be commercially viable to develop any portion of the Contingent Resources.
7. Contingent Resources for gas include the removal of inerts and removal of condensate (17 – 23%).

Table 1.4: Gross On-block Unrisked Prospective Resources

Prospect	Gross On-Block Gas Prospective Resources (Bscf)				Gross On-Block Condensate Prospective Resources (MMstb)				COS (%)
	1U	2U	3U	Mean	1U	2U	3U	Mean	
Chuditch NE	163	516	1556	744	0.6	2.3	9.2	4.0	30%
Chuditch SW Alpha	139	326	729	394	0.4	1.4	4.6	2.1	52%
Chuditch SW Beta	107	238	505	281	0.3	1.1	3.2	1.5	45%
Quokka	27	94	314	143	0.1	0.4	1.8	0.8	26%

Table 1.5: Net Working Interest Unrisked Prospective Resources

Prospect	SundaGas Working Interest	Net Working Interest Gas Prospective Resources (Bscf)				Net Working Interest Condensate Prospective Resources (MMstb)				COS (%)
		1U	2U	3U	Mean	1U	2U	3U	Mean	
Chuditch NE	75%	122	387	1167	558	0.4	1.7	6.9	3.0	30%
Chuditch SW Alpha	75%	105	244	547	296	0.3	1.1	3.4	1.6	52%
Chuditch SW Beta	75%	80	179	379	211	0.3	0.8	2.4	1.1	45%
Quokka	75%	20	70	236	108	0.1	0.3	1.4	0.6	26%

Notes

1. Gross On-block Prospective Resources are limited to within PSC TL-SO-19-16 and are based on percentage on-block x total Gross Prospective Resources.
2. Company working interest is based on a SundaGas working interest of 75.00 percent following development and first gas. SundaGas are carrying the remaining 25.00 percent interest to development.
3. Company Net Working Interest Prospective Resources are based on the working interest share of the field post development x Gross On-Block Prospective Resources and are prior to deduction of royalties.
4. Company net entitlement Contingent Resources require a full economic evaluation which has not been done as part of this CPR and hence are not presented
5. The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS 2018 guidelines.
6. In the case of Prospective Resources, there is no certainty that hydrocarbons will be discovered, nor if discovered will be commercially viable to produce any portion of the resources.
7. These are unrisked Prospective Resources that have not been risked for chance of development.
8. Prospective Resources for gas include the removal of inerts and removal of condensate (17 – 23%).

At the request of SundaGas, ERCE has also included a summary of SundaGas' volumetric estimates and geological chance of success in Appendix 1.

2. Introduction

2.1. Leases and Exploration History

The TL-SO-19-16 production sharing contract (PSC) is situated within the Bonaparte Basin approximately 185 km south of Timor-Leste. SundaGas is the Operator of the PSC with 75% working interest with the remaining 25% interest held by the subsidiary of the Timor-Leste state oil company, TIMOR GAP E.P ("TIMOR GAP"). TIMOR GAP's interest is carried by SundaGas to development.

The Chuditch gas discovery and surrounding prospects are located approximately 130 km east of the producing Bayu-Undan field, and 100 km south of the Greater Sunrise potential development (Figure 2.1).

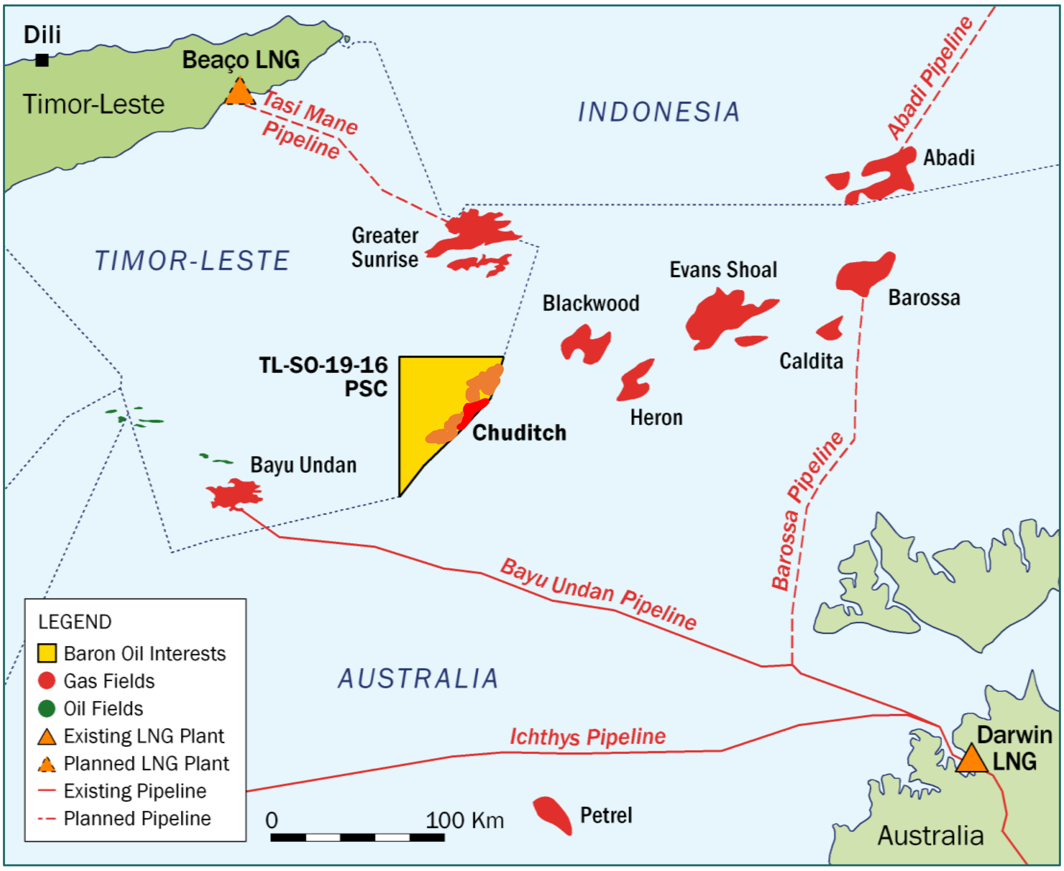

Figure 2.1: Licence TL-SO-19-16 PSC location map

Source: SundaGas

Chuditch was discovered in 1998 with the drilling of Well Chuditch-1 by Shell. The well penetrated 2,946 m of sedimentary rocks ranging in age from Recent to Middle Jurassic, reaching total depth within the Plover Formation. The well was drilled in a water depth of 64 m. The average water depth across the Chuditch area is approximately 70 m. The well encountered 120 m of gross Middle Jurassic Plover Formation to TD, of which the upper 30 m were above the interpreted free water level (FWL).

2.2. Geological Setting

The Chuditch discovery is located within the Bonaparte Basin and lies on the north-western margin of the Malita Graben (Figure 2.2).

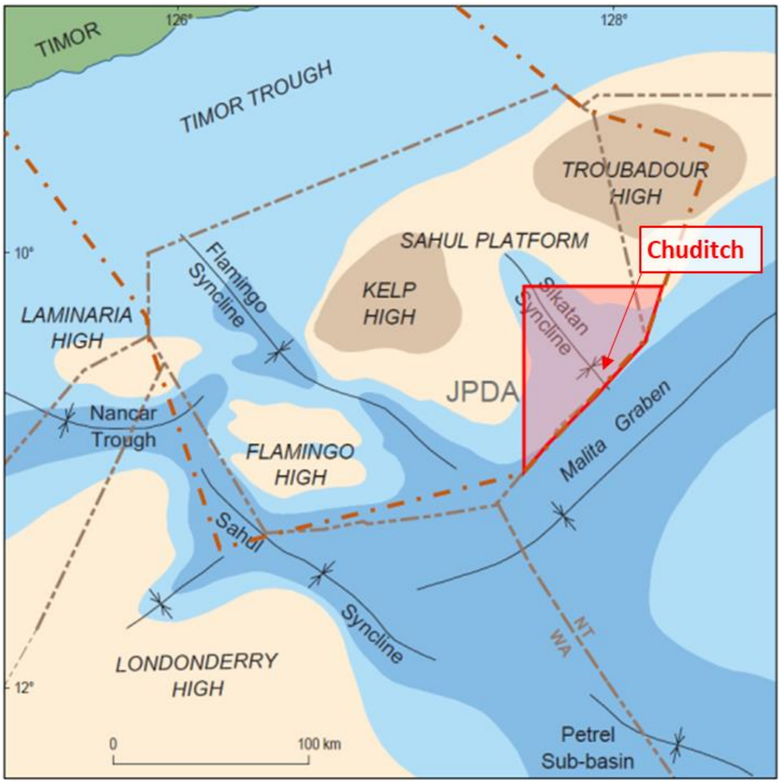

Figure 2.2: Location of the Chuditch discovery in the Bonaparte Basin

Source: SundaGas

The petroleum system lies within the Jurassic and Early Cretaceous succession, with the reservoir unit within the Mid-Jurassic age Plover Formation. The generalised stratigraphy of the Bonaparte Basin and the petroleum system of the Chuditch discovery is illustrated in Figure 2.3. The gas resources are contained within the Plover Formation, which is a regionally extensive fluvio-deltaic to marginal marine sandstone of Sinemurian to Bathonian age. Most wells in the area reach TD within the Plover formation. Chuditch-1 reached TD after penetrating 120 m of Plover section.

The Chuditch-1 discovery is a fault bound 3-way dip-closed elongate structure which lies in the vicinity of the NE-SW trending Malita Graben bounding normal fault. The surrounding prospects are defined by other faults following a similar SW-NE trend.

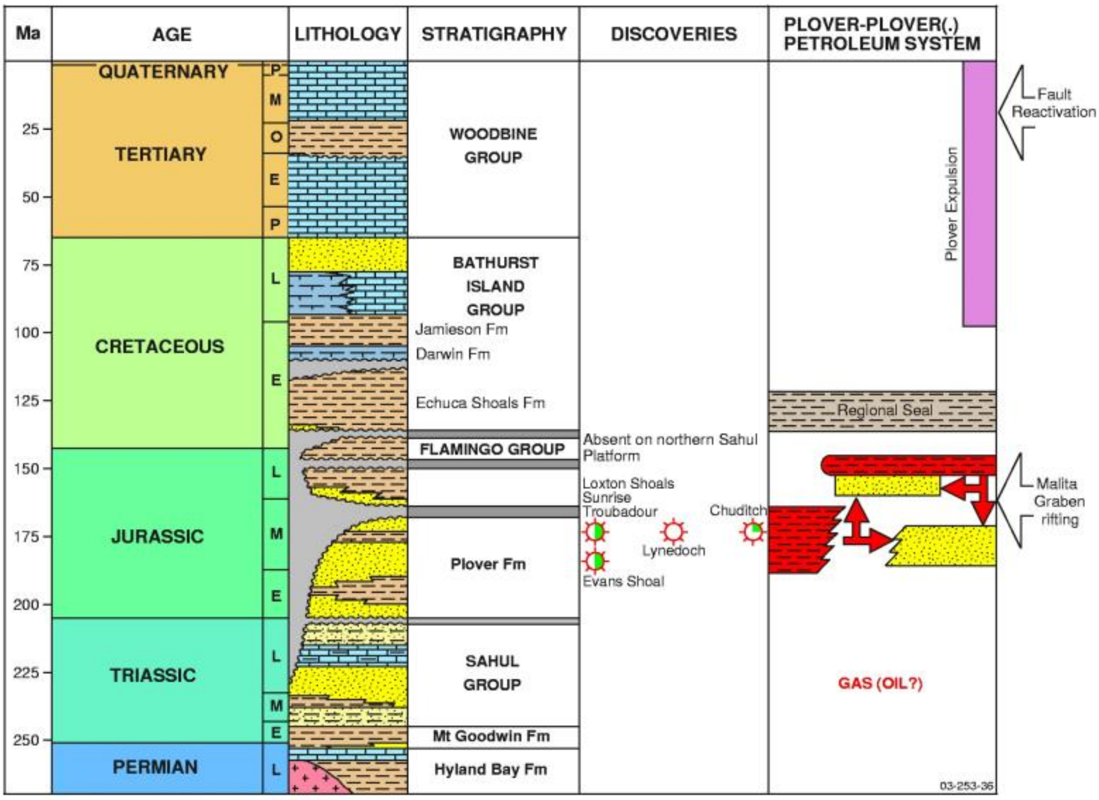

Figure 2.3: Generalised lithostratigraphy of Bonaparte Basin and the plover petroleum system of the Chuditch discovery

Source: Geoscience Australia

The Malita Graben forms part of a major rift system trending northeast and is bounded by large displacement normal faults. The most likely source rocks charging the Chuditch area are intra-Plover coaly shales, with possible additional contributions from the mudstones of the Late Jurassic – Lower Cretaceous Flamingo Group and Elang Formation. These sediments form part of the expanded Mesozoic and Cenozoic section of the Malita Graben.

The Plover Formation is expected to be sealed beneath mudstones of the Upper Jurassic – Lower Cretaceous Flamingo Group, where present, and the Echuca Shoals Formation which provides a continuous regional seal.

2.3. Seismic Data

The seismic interpretation of the Chuditch-1 discovery is based on the 2022 PSDM, Full Waveform Inversion (FWI) reprocessing of a 1,270 km^2 volume which is part of the 9,000 km^2 2012 Kyranis 3D Survey (Figure 2.4). SundaGas engaged TGS in the reprocessing of this volume as part of an overall reprocessing project of the entire survey. The main aim of the PSDM was to improve the velocity field given the complex seabed and near-surface geology, to provide a better structural image. The secondary aim was to improve definition of the fault that bounds the Chuditch-1 discovery and to improve the seismic signal of the sequences close to the fault. The reprocessing study was completed in Q3 2022 and resulted in uplift in reflector quality and continuity at the near top reservoir level, improved definition of the fault terminations and resolution of the shallow velocity distortions.

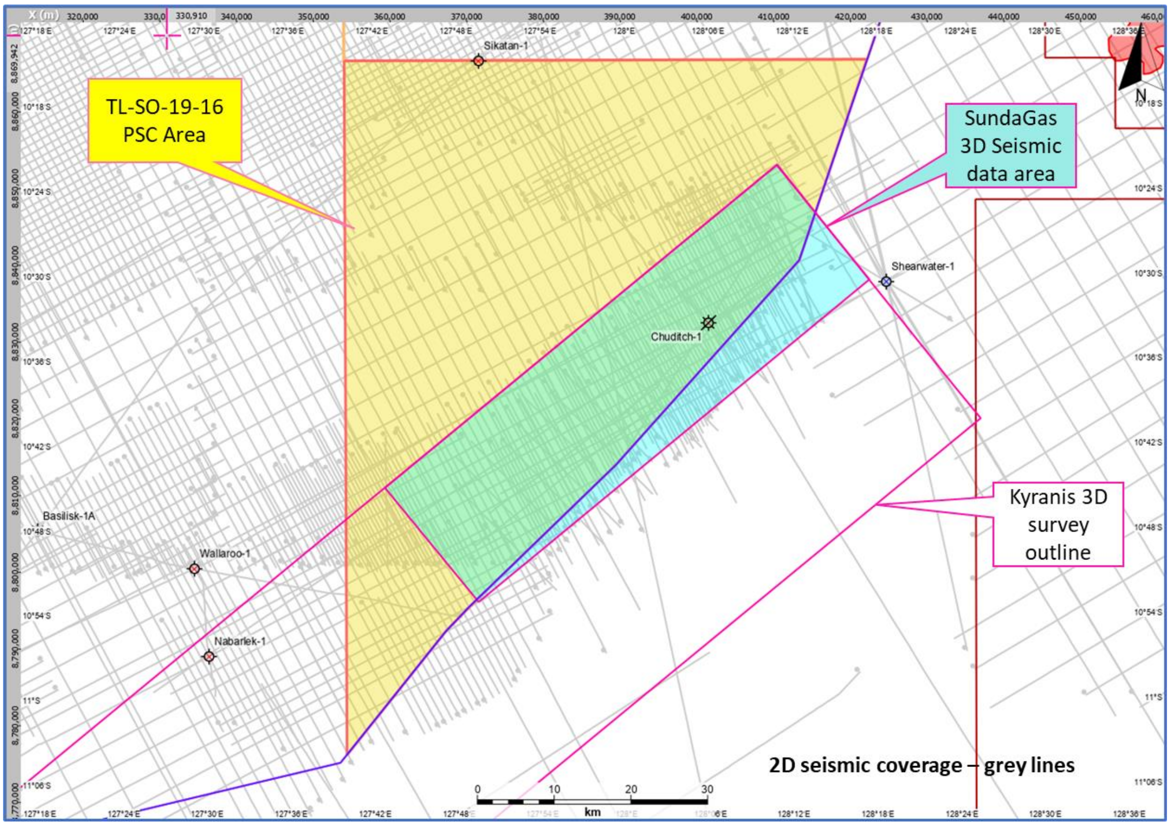

Figure 2.4: Location map of 2022 reprocessed 3D PSDM dataset and the TL-SO-10-16 PSC licence area

Two prospects, Chuditch NE and Quokka, extend beyond the 3D seismic survey and seismic interpretation is based on both 3D and 2D datasets. The seismic data quality varies both vertically and horizontally across the discovery as fault shadow complexities and bathymetric channels create seismic imaging anomalies.

3. Chuditch-1 Discovery & Prospects

3.1. Geology and Geophysics

The Chuditch-1 discovery is well defined on the available seismic data as a three-way dip closure against the NE-SW trending fault that parallels the main Malita Graben bounding normal fault. Further prospectivity can be identified along strike from the Chuditch-1 discovery, within the Chuditch SW structure. The overall closure of Chuditch SW can be divided into two areas which ERCE defines as two prospects, Alpha and Beta (Figure 3.1).

The Quokka and Chuditch NE prospects (Figure 3.1) extend beyond the 3D seismic volume and are partly mapped on 2D. The Quokka prospect is mapped as an elongate fault bounded 3-way dip closed structure on a separate fault block to the Chuditch-1 discovery. The Chuditch

NE prospect is also mapped as a fault bounded 3-way dip closed structure with potential spill towards the Chuditch-1 discovery in the High Case.

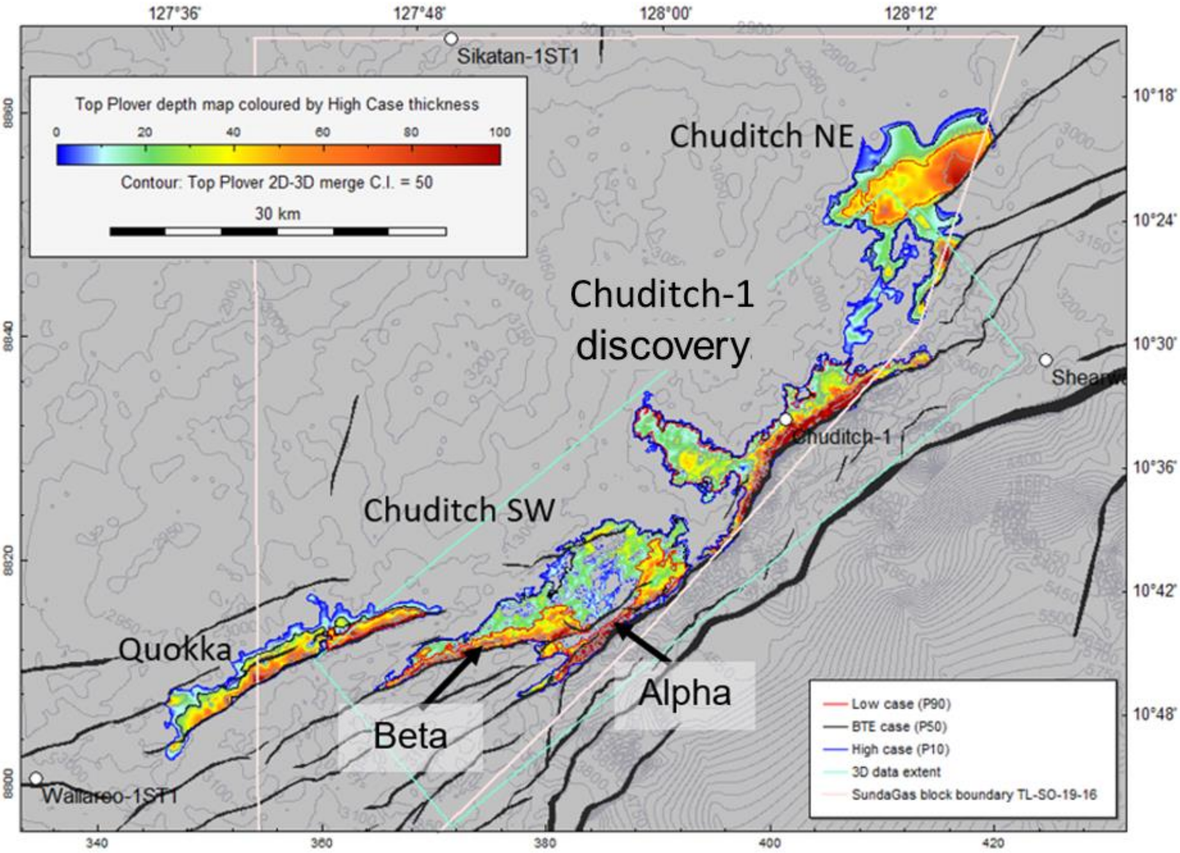

Figure 3.1: SundaGas' Merged 3D final PSDM / 2D Top Plover depth structure map

Depth contours colour above High Case closure. Mid and Low case contacts are shown by the black and red contours respectively. (Source: Adapted from SundaGas)

3.1.1. Seismic Interpretation

ERCE has reviewed SundaGas' seismic interpretation on the 2022 3D PSDM seismic and considers it to be reasonable (Figure 3.2). ERCE notes there is uncertainty in the interpretation in areas close to the bounding fault in the interpretation of these events and also the position of the bounding fault.

The Top Plover reservoir event is not resolvable on the seismic image. The Top Darwin event, which sits immediately above the Top Plover formation, is a strong seismic reflection. SundaGas generate a Top Plover reservoir surface by adding an 18 m isopach to the Top Darwin surface, based on the isopach between these tops in Well Chuditch-1.

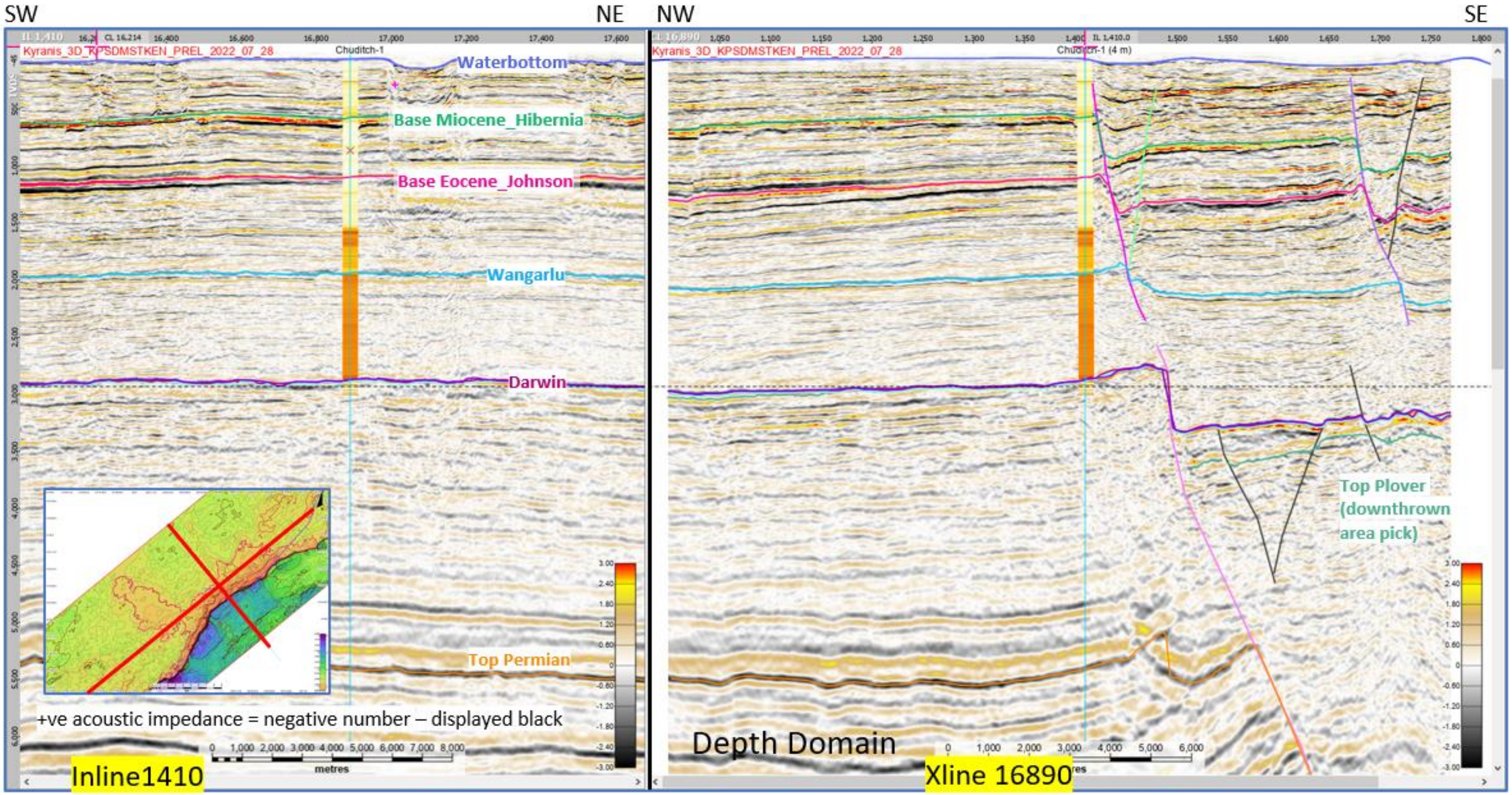

Figure 3.2: PSDM Full Stack - mapped seismic horizons and Well Chuditch-1

(Source: SundaGas)

3.1.2. Depth Conversion

Depth imaging of the near-Top Plover surface is challenging owing to the presence of seabed topography and shallow carbonates; hence SundaGas' application of PSDM processing. The seafloor bathymetry across the Chuditch area shows incised seabed channels and several surface reefs that distort the seismic signal of the strata directly underlying the features. The main bounding Chuditch fault may also accentuate imaging uncertainties around the fault shadow.

While the PSDM provides a base case structural top reservoir model, to account for the uncertainties in the velocity model, ERCE has considered several interval velocity and linear depth conversion models for the Chuditch-1 discovery and nearby prospects.

ERCE use SundaGas' depth interpretation of the reprocessed PSDM data, converted to two-way time (TWT) using the smoothed PSDM velocity field, as the inputs for our alternative depth conversions. The various depth conversion models aim to investigate sensitivities associated with fault shadow, overburden velocity and smoothed grids. The models each contain five rock layers consisting of Seabed, Base Miocene, Top Johnson, Top Wangarlu, Top Darwin and Top Plover (Figure 3.2). ERCE has then compared the resulting depth surfaces to those generated using PSDM velocities and finds both sets to be reasonable scenarios for volumetric consideration.

ERCE's depth-converted Top Plover grids are illustrated in Figure 3.3 below. Where appropriate, ERCE has made edits to the Top Plover depth grid to take into consideration velocity artefacts associated with incised seabed channels by smoothing the grid to an average depth observed directly outside the seabed channel.

The Chuditch NE and Quokka prospects extend beyond the 3D seismic volume extent. Densely spaced 2D seismic data is present over the Quokka prospect, whereas 2D seismic spacing is moderate to sparse over the Chuditch NE prospect. ERCE has extrapolated velocity surfaces from the area of 3D seismic coverage to depth convert these prospects.

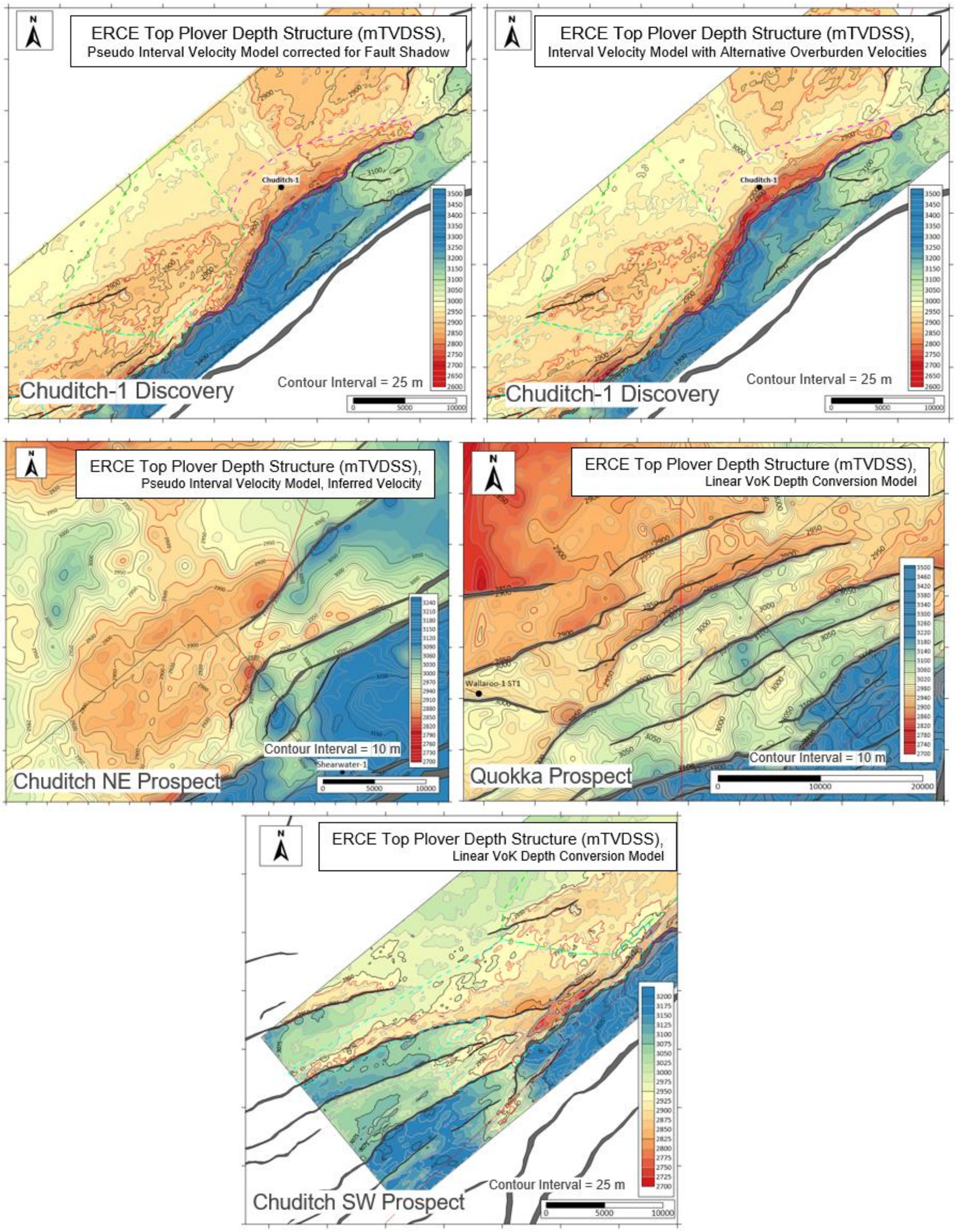

Figure 3.3: ERCE Top Plover depth-converted grids in mTVDSS.

High Case contact assumptions are shown by the red contour

3.2. Petrophysics

A quantitative petrophysical interpretation was performed on Well Chuditch-1 and the results are consistent with SundaGas' petrophysical interpretation.

ERCE has evaluated a salinity value of 22,000 ppm NaCl equivalent with a=1, m*= n*=2.2 using a Pickett plot (Figure 3.4). Water samples collected from the had a salinity value of ~36,000 ppm NaCl. However they are likely to be contaminated. We have used the Horner corrected temperatures and geothermal gradient as provided by SundaGas, at 4^{O}C/100m which is in line with regional data.

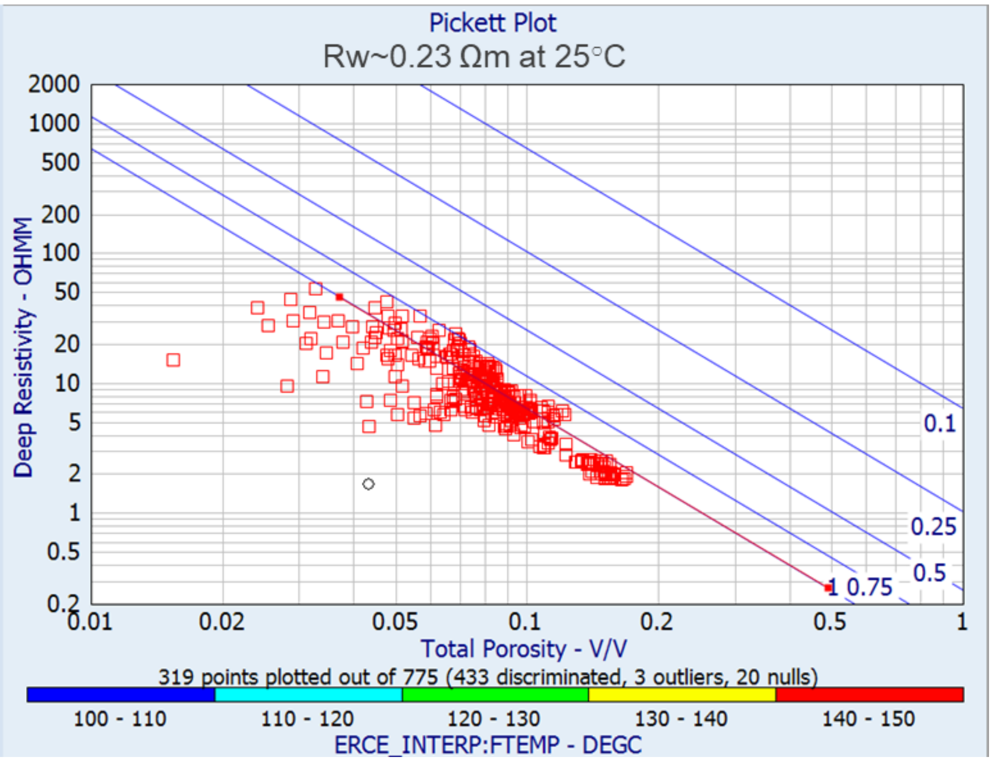

Figure 3.4: Pickett Plot, Plover Formation, Well Chuditch-1

3.2.1. Core Analysis

A core was cut from the Plover formation from 2921.4 – 2947 mMD; a total of 25.6 m of core was recovered (100% recovery). Figure 3.5 shows the overburden corrected porosity and permeability cross-plot. The low porosity, high permeability points shown on the graph are non-conformable with the overall porosity-permeability trend and are likely caused by striations or microfractures in the reservoir. These points are therefore excluded from the overall porosity-permeability trend line estimation. Assuming a 0.1 mD permeability cut-off value as producible reservoir, a porosity cutoff of ~5 p.u. is obtained.

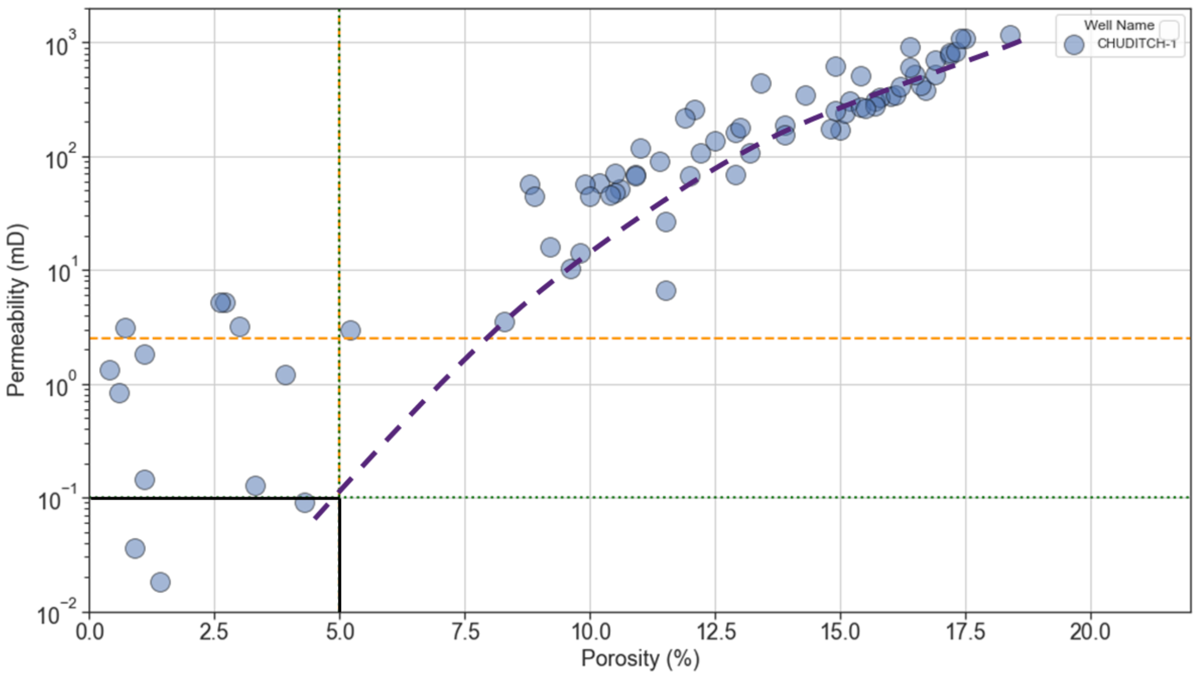

Figure 3.5: Plot of overburden-corrected porosity and permeability

3.2.2. Petrophysical Evaluation Methodology

Log quality in the wells was good; there were no observed issues with either the borehole or the measured log data. Synthetic based mud was used in the drilling of the well. While wireline formation pressure data (modular dynamic tester, MDT) and core was collected, there was no drill stem test conducted to determine production rates.

ERCE has independently interpreted Volume of Shale (VSH), Total Porosity (PHIT) and Total Water Saturation (SWT) curves. VSH is interpreted from the GR and D-N, while PHIT is interpreted from D-N with hydrocarbon and shale corrections applied. SWT is interpreted using the Dual Water Approach where m* = n* = 2.2. ERCE has also performed an interpretation of Volume of Clay (VCL; the assumption being that VCL = 0.6*VSH), Effective Porosity (PHIE) and Effective Water Saturation (SWE).

Utilising the core data and from observation on the logs, ERCE has independently interpreted the well with the following cut-offs: the final cutoffs applied are VSH ≤ 0.30, PHIT ≥ 0.05 and SWT ≤ 0.75. Note that 5 p.u. porosity is roughly equivalent to 0.1 mD, as shown in ERCE's porosity-permeability cross-plot in Figure 3.5.

The computer processed interpretations (CPI) of Well Chuditch-1 is shown in Figure 3.6 and Figure 3.7. Tables of net reservoir and pay statistics generated by ERCE's interpretation is given in Appendix 2. Core data points are given by the filled red symbols. A log derived gas down to (GDT) and water up to (WUT) of 2916 mTVDSS and 2923 mTVDSS are observed.

Both the client and ERCE show similar results in terms of volume of shale, porosity and saturation (ERCE – solid black line, client – dashed red line). ERCE evaluated net reservoir flags are given in dark green, ERCE evaluated net pay flags are given in red. Similarly, client provided net reservoir flags are given in lime green, and net pay flags are given in orange. Given the similarity between ERCE and the clients petrophysical interpretation, ERCE has accepted the client values.

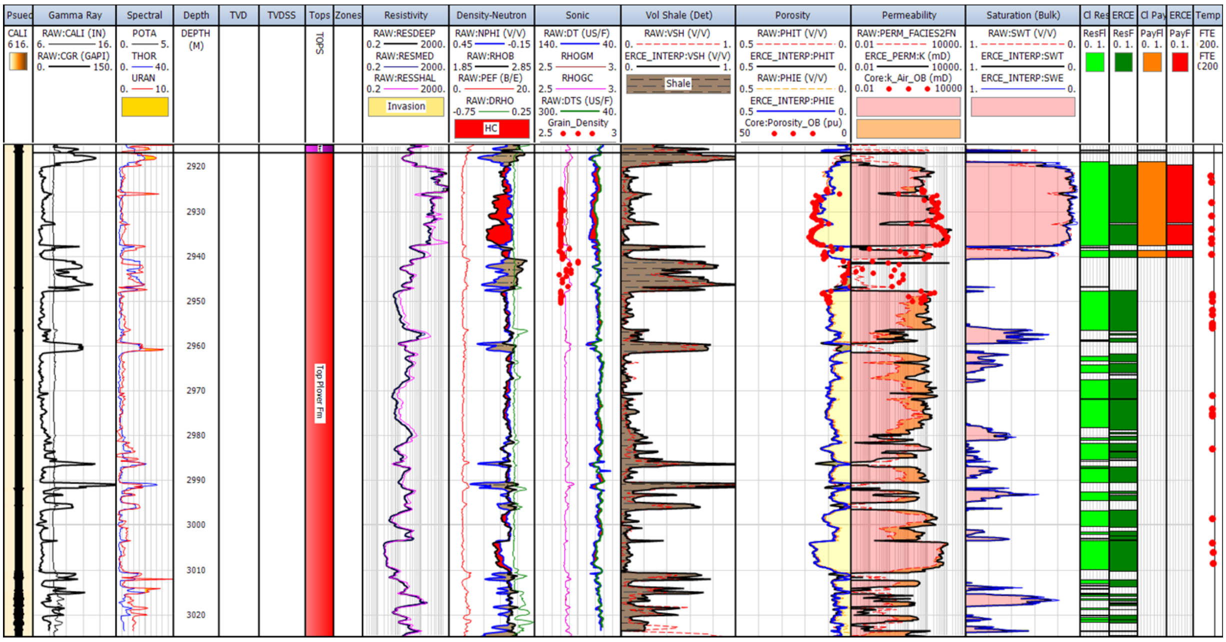

Figure 3.6: CPI for Well Chuditch-1 (ERCE - black, Client – red curves)

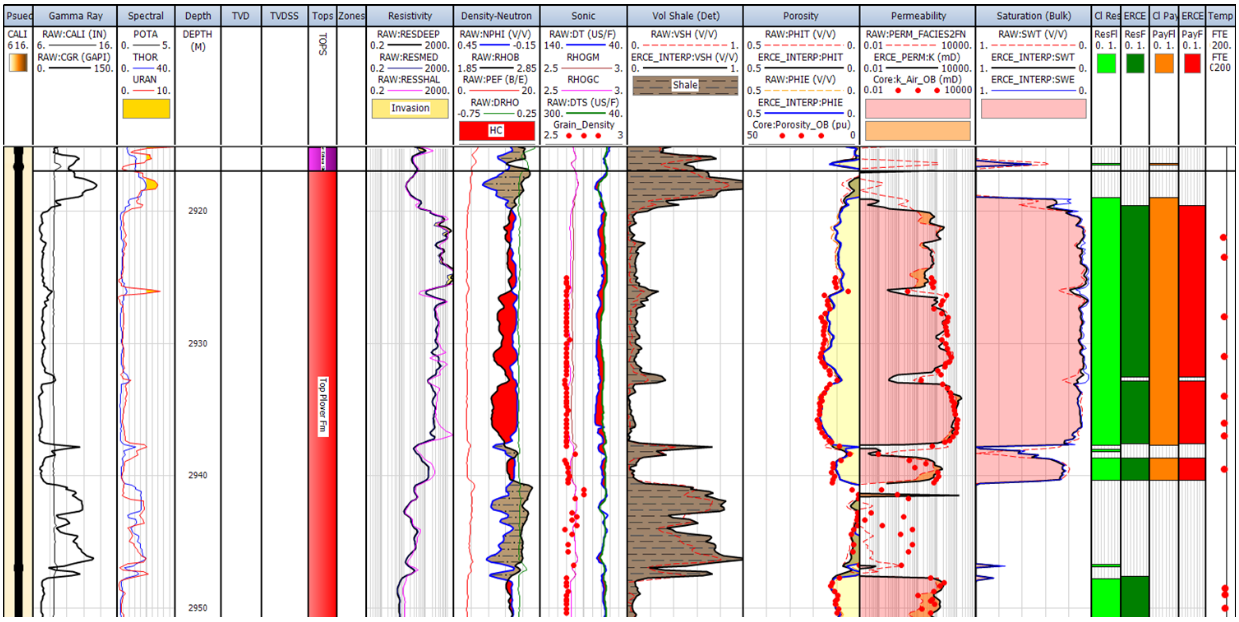

Figure 3.7: CPI for Well Chuditch-1 Zoomed in (ERCE - black, Client – red curves)

3.3. Reservoir Engineering

3.3.1. Fluid Properties

Six bottomhole MDT samples were collected from Well Chuditch-1. However, all were contaminated with drilling mud. Thus, only a compositional analysis was performed by the operator. The gas composition is predominately methane at 77% on average with 18% CO_2 and 2.4% N_2.

Based on the pressure drawdown during acquisition, the gas in Well Chuditch-1 is wet gas with a low CGR (Condensate Gas Ratio) and a dew point pressure of 3,615 psia (75% of the reservoir pressure). ERCE has used a consistent CGR across the Chuditch-1 discovery and surrounding prospects. The range of CGR for the Chuditch-1 discovery and the prospects estimated by ERCE is summarised in Table 3.1.

Table 3.1: Estimated range of condensate gas ratio for the Chuditch-1 discovery and other prospects

Discovery / Prospect	Condensate Gas Ratio (bbl/MMscf)		
	Low	Best	High
Chuditch-1	2	4.5	10
Surrounding Prospects	2	4.5	10

Table 3.2 summarises ERCE's estimates of the percentage of gas impurities that is applied to ERCE's volumetric estimates for the Chuditch-1 discovery and surrounding prospects.

Table 3.2: Estimated range of gas impurities for the Chuditch-1 discovery and other prospects

Discovery / Prospect	Gas impurities (%)		
	Low	Best	High
Chuditch-1	23	20	17
Surrounding Prospects	23	20	17

ERCE's estimates of the average reservoir depth, reservoir temperature and reservoir pressure for each structure have been used to estimate the Gas Expansion Factors (GEF) summarised in Table 3.3. Pressure and temperature have been estimated as a function of reservoir depths from available well data.

Table 3.3: Gas expansion factor estimates for the Chuditch-1 discovery and other prospects

Discovery / Prospect	Formation Volume Factor (scf/rcf)		
	Low	Best	High
Chuditch-1	201	212	223
Surrounding Prospects	201	212	223

3.3.2. Fluid Contacts

ERCE has reviewed the available MDT data for Well Chuditch-1 and has estimated gas and water gradients to determine the inferred free water level (FWL). Subsequent use of GWC for the Chuditch-1 discovery refers to the FWL inferred by MDT data.

The pressure versus depth plot for Well Chuditch-1 is illustrated in Figure 3.8 and shows a GWC observed at 2,920 mTVDSS. The results of the pressure-depth plot are within the log derived GDT and WUT estimates described in Section 3.2.2.

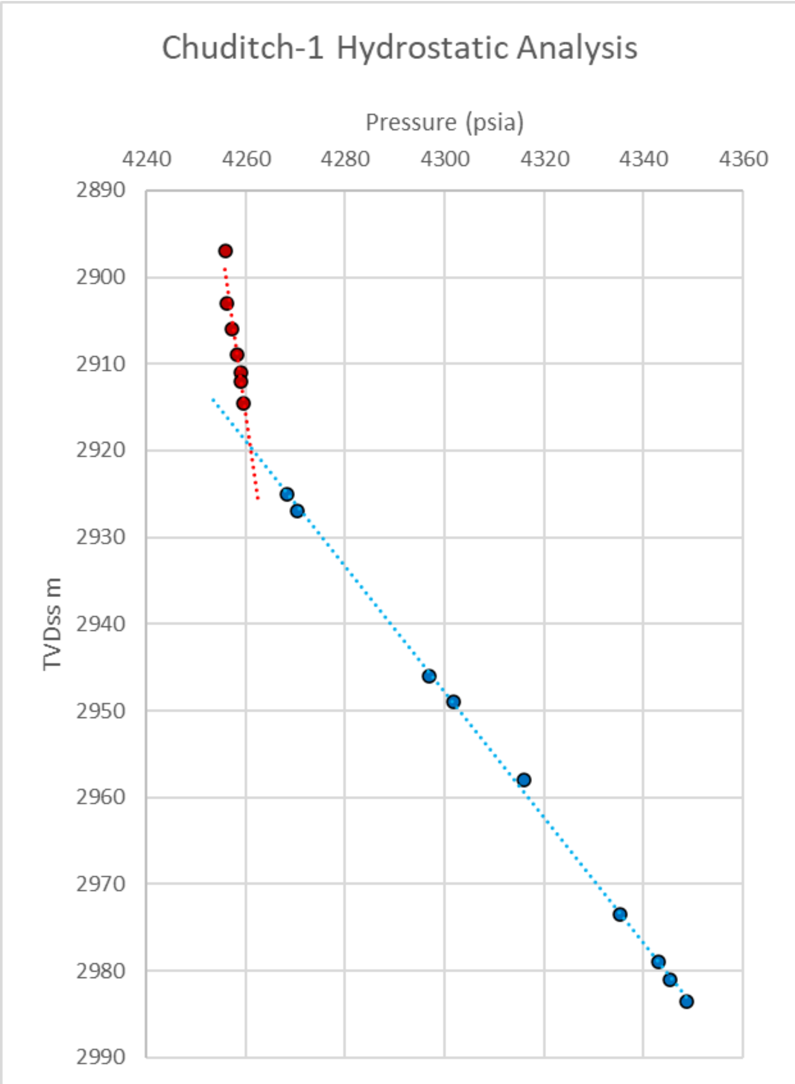

Figure 3.8: Well Chuditch-1 pressure vs. depth plot

3.3.3. Recovery Factors

The reservoir drive mechanism for the Chuditch-1 discovery and the nearby prospects is expected to be aquifer drive due to the regionally extensive high N/G nature of the Plover Reservoir and the observation of aquifer in analogue fields. Thus, ERCE's Low and Best Case recovery factor considers a dominant water drive mechanism while ERCE's High Case recovery factor considers a dominant depletion drive mechanism (assuming aquifer influx limited by regional faulting and shale baffles). ERCE built a conceptual PROSPER and MBAL model to evaluate the range of recovery factors, varying the aquifer size, strength, permeability, tubing size, reservoir deliverability, system backpressure and residual gas saturation.

A summary of ERCE's estimates of gas recovery factors for the Chuditch-1 discovery and nearby prospects is shown in Table 3.4. As CGR values are low, minimal drop out is expected in the reservoir, ERCE therefore used the same recovery factor range for gas and condensate.

Table 3.4: Gas recovery factor estimates for the Chuditch-1 discovery and other prospects

Discovery / Prospect	Gas Recovery Factors (%)		
	Low	Best	High
Chuditch-1	45%	62.5%	80%
Prospects	45%	62.5%	80%

3.4. Estimation of Hydrocarbons in Place and Resources

ERCE has independently estimated GIIP and Contingent Resources for the Chuditch-1 discovery, using probabilistic methods. For the Chuditch-1 discovery, the Plover reservoir is divided into two layers based on reservoir properties observed in Well Chuditch-1 (see Section 3.2.2 and Appendix 2). The High Perm Plover layer refers to the higher permeability gas bearing zone of Well Chuditch-1. The Low Perm and Unknown Plover layer refers to the lower permeability water bearing reservoir of Well Chuditch-1 and possible Plover reservoir below TD of the well. This layer is extrapolated to enter the gas leg in the structure updip of the well location.

3.4.1. HIIP and Contingent Resources

3.4.1.1. Chuditch-1 Discovery

ERCE Low and High Case gross rock volume (GRV) estimates are derived from two different Top Plover depth maps made using alternative depth conversion models as described below. The Low and High Case GWC of 2,920 mTVDSS is based on results from Well Chuditch (see Section 3.3.2).

A +/- 20% factor is applied to these high and low case GRVs to model the effect of the additional uncertainties associated with reservoir thickness, seismic interpretation and fault positioning. ERCE's Low and High Case GRV estimates were set to the ninetieth and tenth percentiles of a log-normal distribution for use in a probabilistic simulation of GIIP.

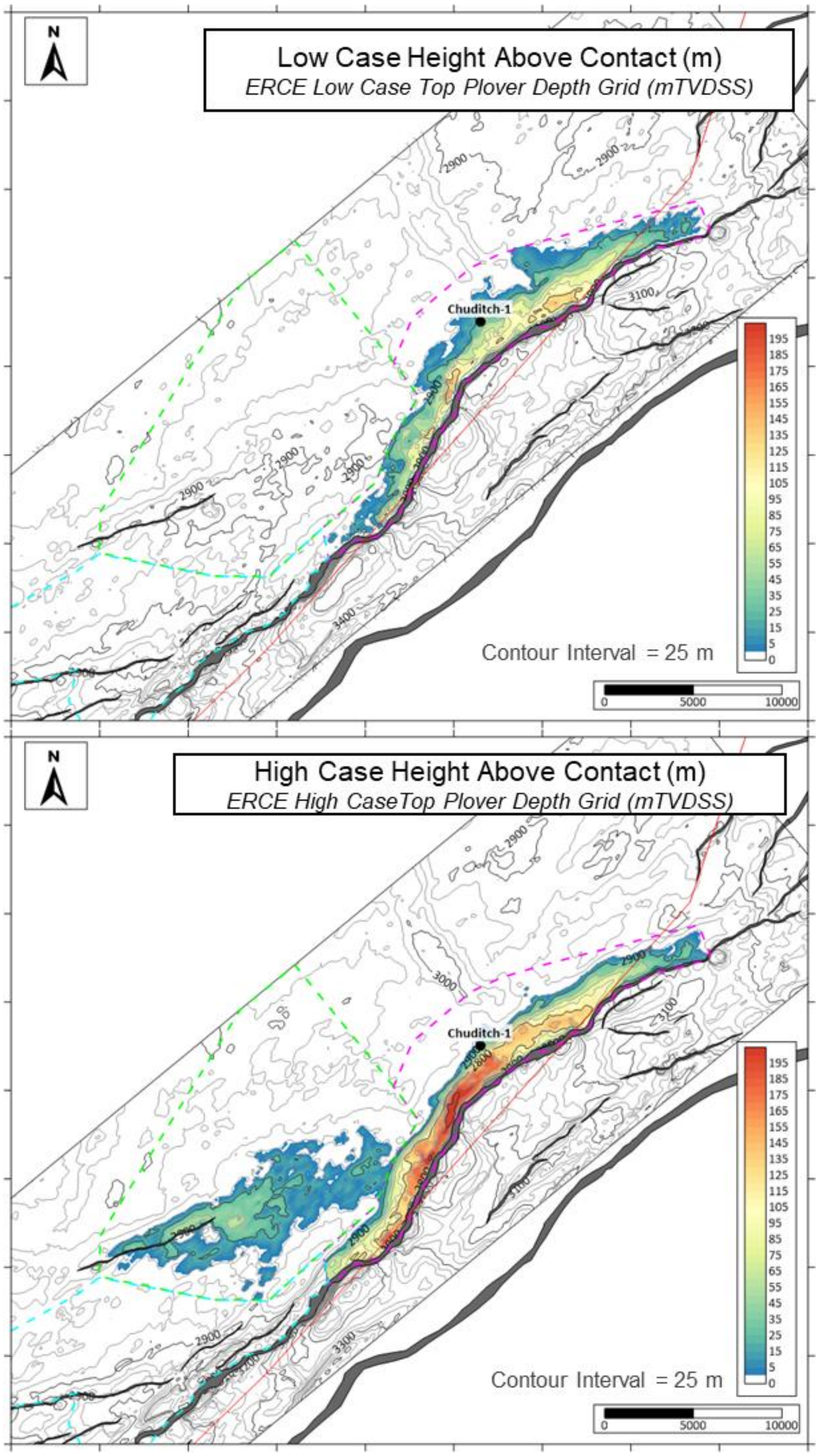

Figure 3.9: ERCE Chuditch-1 discovery Low (top) and High (bottom) Case Height Above Contact maps

Overlayed with Top Plover depth contours (m TVDSS)

ERCE's Low case depth structure map is based on an interval velocity depth conversion model which considers the fault shadow effect along strike of the structure and a 200 m uncertainty in the bounding fault interpretation. Thickness changes across the bounding fault scarp cause lower velocities in the vertical depth conversion model at Top Plover. ERCE has modified our Top Plover average velocity grid by blanking and smoothing across the anomaly.

ERCE's High Case depth structure map is based on a depth conversion model with overburden interval velocities guided by the those observed in Well Chuditch-1. The High Case assumes connected volumes to the west of the main crestal structure. The depth structure map in both the Low and High case has been modified to correct for the seabed channel anomaly.

For the petrophysical inputs, ERCE used sums and averages from net reservoir and pay statistics discussed in Section 3.2.2 and Appendix 2.

The gas expansion factors (GEF) were based ERCE's estimates discussed in Section 3.3.1. All volumetric estimates include the removal of inerts as discussed in Section 3.3.1 with a reduction of 17% - 23% applied probabilistically. Condensate gas ratios (CGR) are based on compositional analysis results discussed in Section 3.3.1.

ERCE's input parameters for the estimation of hydrocarbons in place are summarised in Table 3.5. The results of ERCE's probabilistic simulation of GIIP are summarised in Table 3.6.

Table 3.5: ERCE Chuditch-1 discovery – Volumetric input parameter ranges

Discovery	GRV (MMm3)			NTG (frac)			Porosity (frac)		
	Low	Best	High	Low	Best	High	Low	Best	High
High Perm	891	1412	2237	0.75	0.85	0.95	0.100	0.125	0.150
Low Perm and Unknown	1080	2256	4711	0.65	0.75	0.85	0.075	0.100	0.125
Chuditch-1	1971	3667	6948						

Discovery	SHc (frac)			GEF (scf/rcf)			RF (frac)		
	Low	Best	High	Low	Best	High	Low	Best	High
High Perm	0.85	0.90	0.95	201	212	223	0.45	0.63	0.80
Low Perm and Unknown	0.80	0.85	0.90	201	212	223	0.45	0.63	0.80

Table 3.6: ERCE Chuditch-1 discovery - GIIP estimates

Discovery	Discovered GIIP (Bscf)			
	Low	Best	High	Mean
High Perm Plover	471	798	1331	862
Low Perm and Unknown	380	838	1850	1008
Chuditch-1	**851**	**1636**	**3180**	**1870**

Notes

1. GIIP includes volumes outside TL-SO-19-16 PSC.

ERCE has probabilistically applied the estimates of recovery factors discussed in Section 3.3.2. Recovery factors for both the gas and associated condensate case are summarised in Table 3.4, and the results of ERCE's probabilistic simulation of Gross Contingent Resources for gas and condensate are summarised in Table 3.7.

Table 3.7: ERCE Chuditch-1 discovery - Gas and Condensate Gross Contingent Resources

Discovery	Gross Gas Contingent Resources (Bscf)				Gross Condensate Contingent Resources (MMstb)			
	1C	2C	3C	Mean	1C	2C	3C	Mean
High Perm Plover	263	490	871	537	0.8	2.2	5.9	2.9
Low Perm and Unknown	218	509	1178	628	0.7	2.3	7.4	3.4
Chuditch-1	**481**	**999**	**2050**	**1165**	**1.5**	**4.5**	**13.3**	**6.3**

Notes

1. Gross Contingent Resources include volumes outside TL-SO-19-16 PSC.

3.4.2. HIIP and Prospective Resources

Probabilistic GIIP and Prospective Resources were independently estimated for the surrounding prospects using a single Plover reservoir layer. ERCE's probabilistic petrophysical inputs, fluid properties and recovery factor ranges are consistent across each prospect, based on Well Chuditch-1, and are summarised in Table 3.8 below.

Table 3.8: ERCE Chuditch area Prospects - Volumetric input parameter ranges

Plover Formation	NTG (frac)			Porosity (frac)			SHc (frac)		
	Min	P50	Max	P90	P50	P10	P90	P50	P10
Chuditch Prospects	0.55	0.78	1.00	0.08	0.11	0.15	0.80	0.88	0.95

Plover Formation	GEF (scf/rcf)			RF (frac)		
	P90	P50	P10	P90	P50	P10
Chuditch Prospects	201	212	223	0.45	0.63	0.80

The GRV estimations, GIIPs, Resources and geological chances of success are discussed for each prospect in the following sections.

3.4.2.1. Chuditch Southwest Prospects

ERCE has estimated Low and High Case GRV for the two prospects that make up the Chuditch SW structure.

ERCE has estimated GRV using Low and High Case depth structure maps for Top Plover intersected by GWC's of 2,930 m TVDSS (Figure 3.10). The contact assumptions for Chuditch SW considers the uncertainty associated with structural spill of the prospect and connectivity to the Chuditch-1 discovery. ERCE's Low and High Case GRV estimates were set to the ninetieth and tenth percentiles of a log-normal distribution for use in a probabilistic simulation of GIIP.

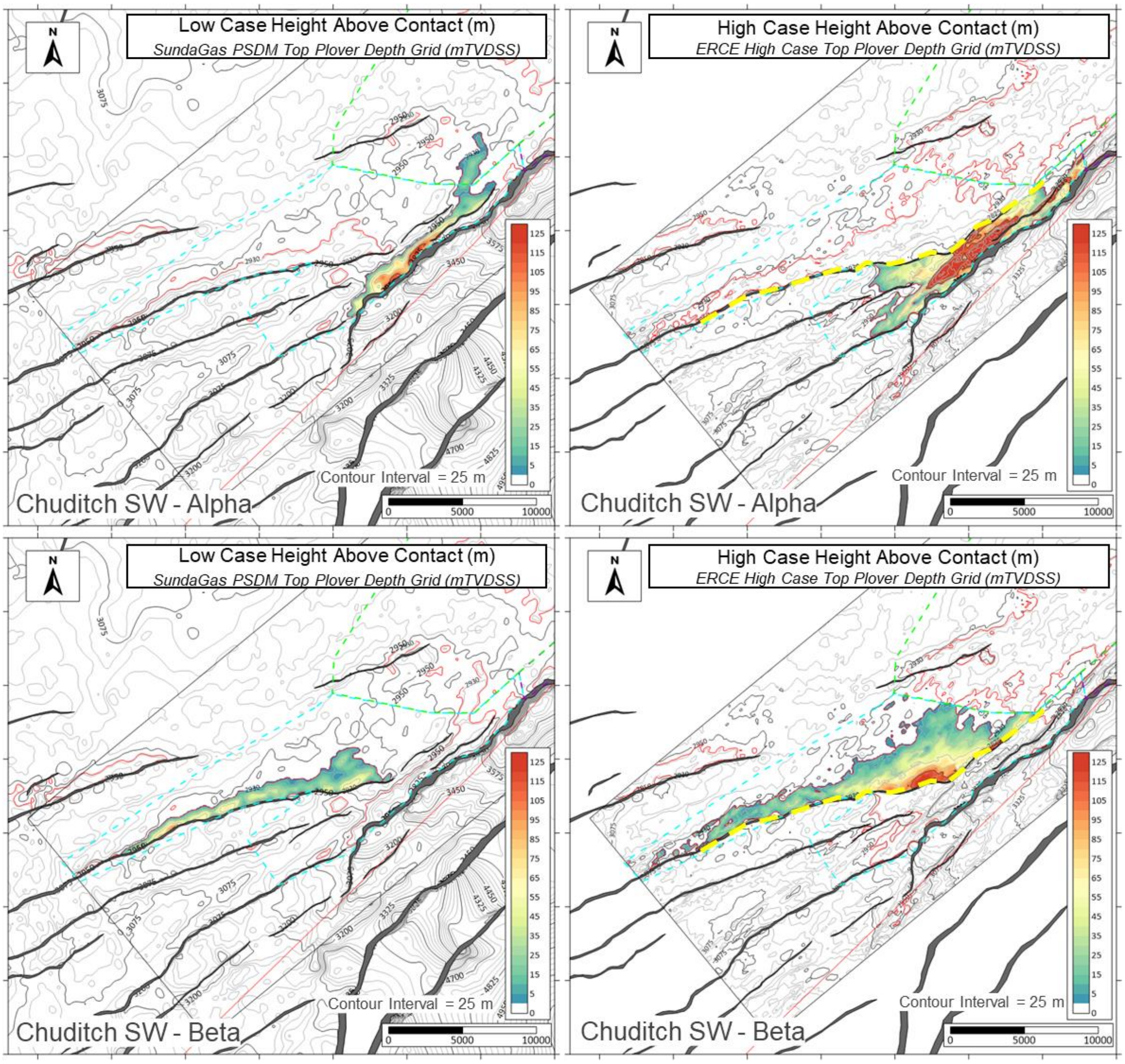

Figure 3.10: ERCE Chuditch SW Alpha (top) and Beta (below), Low (left) and High (right) Case Height Above Contact maps overlayed with Top Plover depth contours (m TVDSS).

ERCE's Low Case depth structure map for Chuditch SW Alpha and Beta are based on the recently reprocessed PSDM Top Plover depth structure made available by SundaGas. The low case closures are separate structures on either side of the fault. The High Case depth structure map is based on ERCE's five-layer linear VoK function depth conversion model that considers compaction of the overburden (see Section 3.1.1).

For the petrophysical inputs, ERCE used sums and averages from net reservoir and pay statistics discussed in Section 3.2.2 and Appendix 2. For probabilistic volumetric simulation the Plover Formation is considered as one unit for each prospect.

The gas expansion factors (GEF) used were as discussed in Section 3.3.1. All volumetric GIIP estimates include the removal of inerts (Section 3.3.1). Condensate gas ratios (CGR) are based on compositional analysis results discussed in Section 3.3.1.

ERCE's input parameters for the estimation of hydrocarbons in place are summarised in Table 3.8 and Table 3.9. The results of ERCE's probabilistic simulation of GIIP are summarised in Table 3.10.

Table 3.9: ERCE Chuditch SW Prospects– GRV input range

Prospect	GRV (MMm3)		
	P90	P50	P10
Chuditch SW Alpha	610	1199	2357
Chuditch SW Beta	474	875	1617

Table 3.10: ERCE Chuditch SW Prospects - GIIP estimates

Prospect	Undiscovered GIIP (Bscf)			
	Low	Best	High	Mean
Chuditch SW Alpha	240	531	1142	630
Chuditch SW Beta	184	388	790	449

ERCE has probabilistically applied the gas recovery factors discussed in Section 3.3.2. Recovery factors for both the gas and condensate case are summarised in Table 3.4. The results of ERCE's probabilistic simulation of Gross Prospective Resources for gas and condensate are summarised in Table 3.11 and are unrisked.

Table 3.11: ERCE Chuditch SW Prospects - Gas and Condensate Gross Unrisked Prospective Resources

Prospect	Gross Gas Prospective Resources (Bscf)				Gross Condensate Prospective Resources (MMstb)			
	1U	2U	3U	Mean	1U	2U	3U	Mean
Chuditch SW Alpha	139	326	729	394	0.4	1.4	4.6	2.1
Chuditch SW Beta	107	238	505	281	0.3	1.1	3.2	1.5

3.4.2.1. Chuditch Northeast Prospect

ERCE has estimated GRV using Low and High Case depth structure maps (Figure 3.11). In the Low Case ERCE limits volumes to the localised closure to the northeast to a spill depth of 2,886 mTVDSS. The High Case contact of 2,920 mTVDSS extends volumes out to the spill point towards the Chuditch-1 discovery. ERCE's Low and High Case GRV estimates were set to the ninetieth and tenth percentiles of a log-normal distribution for use in a probabilistic simulation of GIIP.

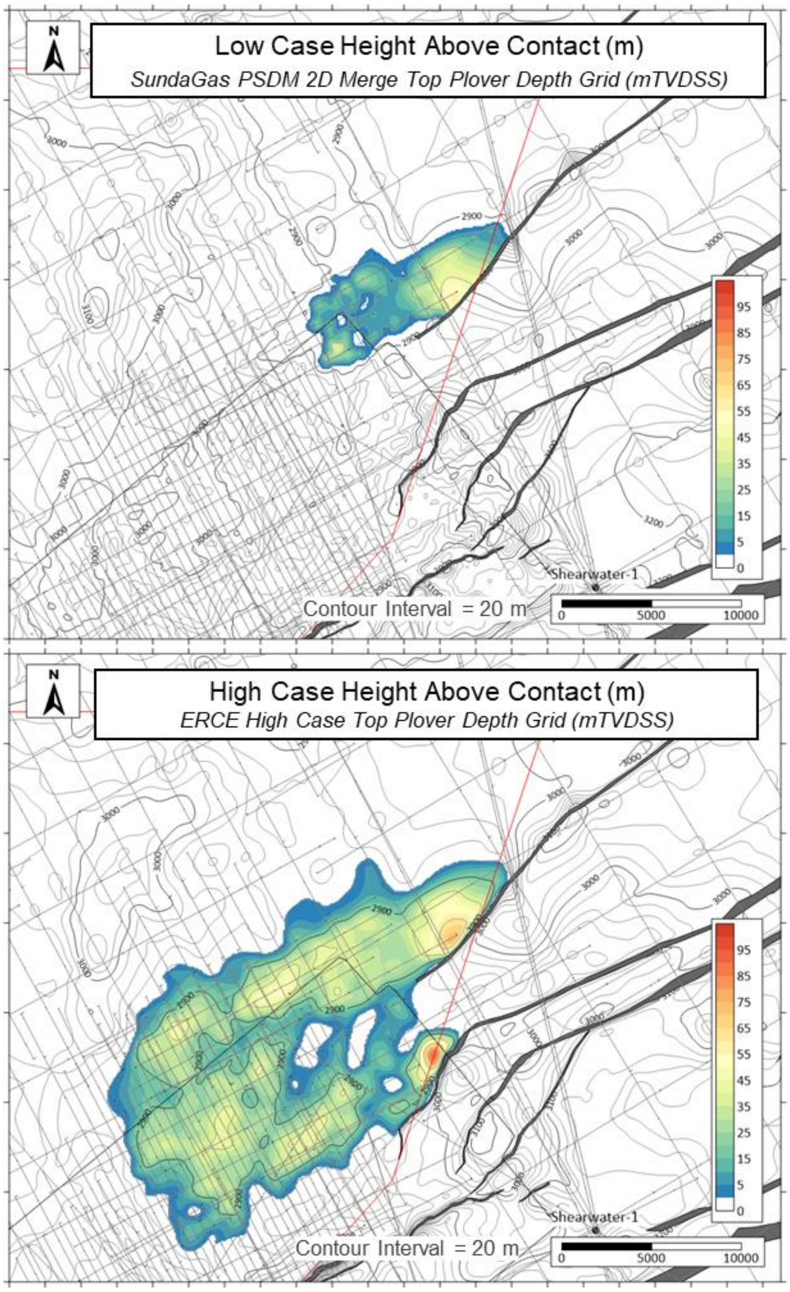

Figure 3.11: ERCE Chuditch NE Prospect Low (top) and High (bottom) Case Height Above Contact maps overlayed with Top Plover depth contours(m TVDSS).

ERCE's Low Case depth structure map is based on the recently reprocessed PSDM Top Plover depth structure made available by SundaGas. The Low Case structural spill to the north is shallowed by an uncertainty of 50 m due to the larger uncertainty associated with the 2D seismic interpretation. The High Case depth structure map is based on ERCE's extrapolated interval velocity depth conversion (see Section 3.1.1).

For the petrophysical inputs, ERCE used sums and averages from net reservoir and pay statistics discussed in Section 3.2.2 and Appendix 2. For probabilistic volumetric simulation the Plover Formation is considered as one unit.

The gas expansion factors (GEF) applied are discussed in Section 3.3.1. All volumetric GIIP estimates include the removal of inerts as discussed in Section 3.3.1. Condensate gas ratios (CGR) applied are discussed in Section 3.3.1.

ERCE's input parameters for the estimation of hydrocarbons in place are summarised in Table 3.8 and GRV is summarised in Table 3.12. ERCE's probabilistic simulation of GIIP is summarised in Table 3.10.

Table 3.12: ERCE Chuditch NE – GRV input range

Prospect	GRV (MMm3)		
	P90	P50	P10
Chuditch NE	697	1939	5393

Table 3.13: ERCE Chuditch NE Prospect - GIIP estimates

Prospect	Undiscovered GIIP (Bscf)			
	Low	Best	High	Mean
Chuditch NE	281	858	2551	1215

Notes
1. GIIP includes volumes outside TL-SO-19-16 PSC.

ERCE has probabilistically applied the recovery factor estimates discussed in Section 3.3.2. Recovery factors for both the gas and condensate case are summarised in Table 3.4.

The results of ERCE's probabilistic simulation of Gross Prospective Resources for gas and condensate are summarised in Table 3.14. These estimates are unrisked.

Table 3.14: ERCE Chuditch NE Prospect - Gas and Condensate Gross Contingent Resources

Prospect	Gross Gas Prospective Resources (Bscf)				Gross Condensate Prospective Resources (MMstb)			
	1U	2U	3U	Mean	1U	2U	3U	Mean
Chuditch NE	167	527	1587	759	0.6	2.3	9.4	4.1

Notes
1. Gross Prospective Resources include volumes outside TL-SO-19-16 PSC.

3.4.2.2. Quokka Prospect

ERCE has estimated GRV using Low and High Case depth structure maps. In the Low Case ERCE assumes the structure is underfilled while the High Case contact of 2,941 mTVDSS assumes the structure is full to spill. ERCE's Low and High Case GRV estimates were set to the ninetieth and tenth percentiles of a log-normal distribution for use in a probabilistic simulation of GIIP.

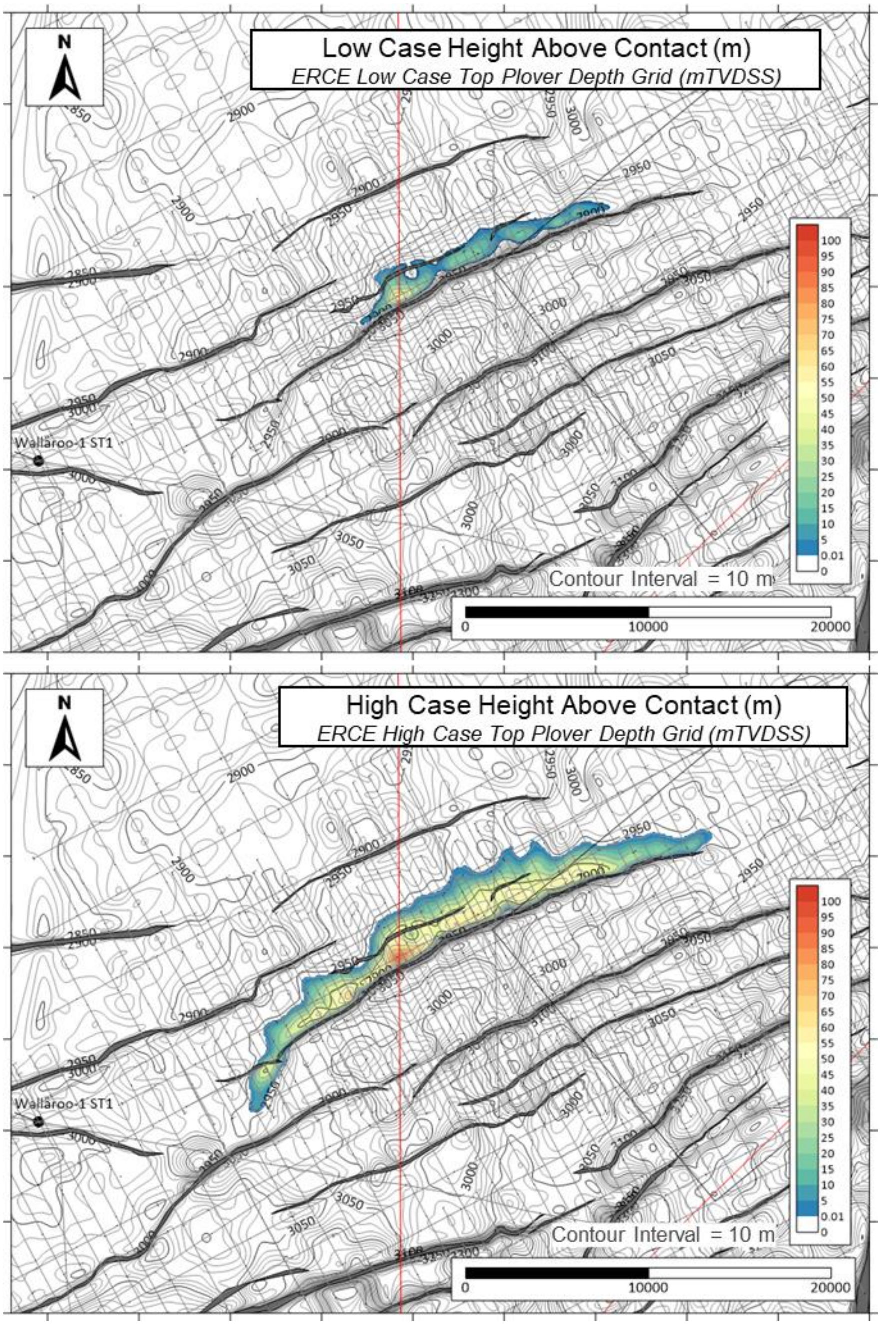

Figure 3.12: ERCE Quokka Prospect Low (top) and High (bottom) Case Height Above Contact maps overlayed with Top Plover depth contours (m TVDSS).

ERCE's Low and High Case depth structure maps are based on a single layer linear VoK function depth conversion (see Section 3.1.1). The High Case Top Plover depth structure map considers a structural spill point 50 m deeper in north due to uncertainties associated with 2D seismic imaging and velocity model.

For the petrophysical inputs, ERCE used sums and averages from net reservoir and pay statistics discussed in Section 3.2.2 and Appendix 2. For probabilistic volumetric simulation the Plover Formation is considered as one unit.

The gas expansion factors (GEF) applied are discussed in Section 3.3.1. All volumetric GIIP estimates include the removal of inerts as discussed in Section 3.3.1. Condensate gas ratios (CGR) are applied as discussed in Section 3.3.1.

ERCE's input parameters for the estimation of hydrocarbons in place are summarised in Table 3.8 and Table 3.15. The results of ERCE's probabilistic simulation of GIIP are summarised in Table 3.10.

Table 3.15: ERCE Quokka Prospect – GRV input range

Prospect	GRV (MMm3)		
	P90	P50	P10
Quokka	171	523	1598

Table 3.16: ERCE Quokka Prospect - GIIP estimates

Prospect	Undiscovered GIIP (Bscf)			
	1U	2U	3U	Mean
Quokka	69	231	749	348

Notes
1. GIIP includes volumes outside TL-SO-19-16 PSC.

ERCE has probabilistically applied the estimates gas and condensate recovery factors as discussed in Section 3.3.2. Recovery factors for both the gas and condensate case are summarised in Table 3.4.

The results of ERCE's probabilistic simulation of Gross Prospective Resources for gas and condensate are summarised in Table 3.17. These estimates are unrisked.

Table 3.17: ERCE Quokka Prospect - Gas and Condensate Gross Prospective Resources

Prospect	Gross Gas Prospective Resources (Bscf)				Gross Condensate Prospective Resources (MMstb)			
	1U	2U	3U	Mean	1U	2U	3U	Mean
Quokka	41	142	469	217	0.1	0.6	2.7	1.2

Notes
1. Prospective Resources include volumes outside TL-SO-19-16 PSC.

3.4.3. Risking

ERCE has used a four-component matrix to estimate the geological chance of success (COS for the Chuditch area prospects (Table 3.18).

Table 3.18: ERCE prospect risk matrix

Prospect	SOURCE (charge and migration)	RESERVOIR (presence and quality)	TRAP (definition and efficacy)	SEAL (presence and efficacy)	COS
Chuditch NE	80%	90%	60%	70%	30%
Chuditch SW Alpha	90%	90%	80%	80%	52%
Chuditch SW Beta	90%	90%	70%	80%	45%
Quokka	70%	90%	60%	70%	26%

For each prospect ERCE considers trap definition as the key risk given the uncertainty in depth conversion and time interpretations, particularly on 2D data. Low reservoir risk is attributed to each prospect as Well Chuditch-1 encountered good quality Plover Formation reservoir. Chuditch SW Alpha and Beta have a low source risk due to its close proximity to Well Chuditch-1 and the Malita Graben kitchen. The seal is proved effective at the Chuditch-1 discovery, which relies on top seal and fault seal. ERCE consider a greater seal risk for Quokka and Chuditch NE due to greater uncertainty in fault seal away from the discovered accumulation.

3.5. Development Plans

SundaGas has commissioned Elite Offshore Timor Lda to perform a study to assess the potential development options for the Chuditch-1 discovery. ERCE has reviewed the report of the study issued January 2023 (REP-EOT-SG-01 Rev 1).

The study concludes that an LNG development is best for Chuditch compared to the other options e.g. piped gas or compressed natural gas.

The infield facilities related to the LNG development concepts are similar to those presented in Figure 3.13.

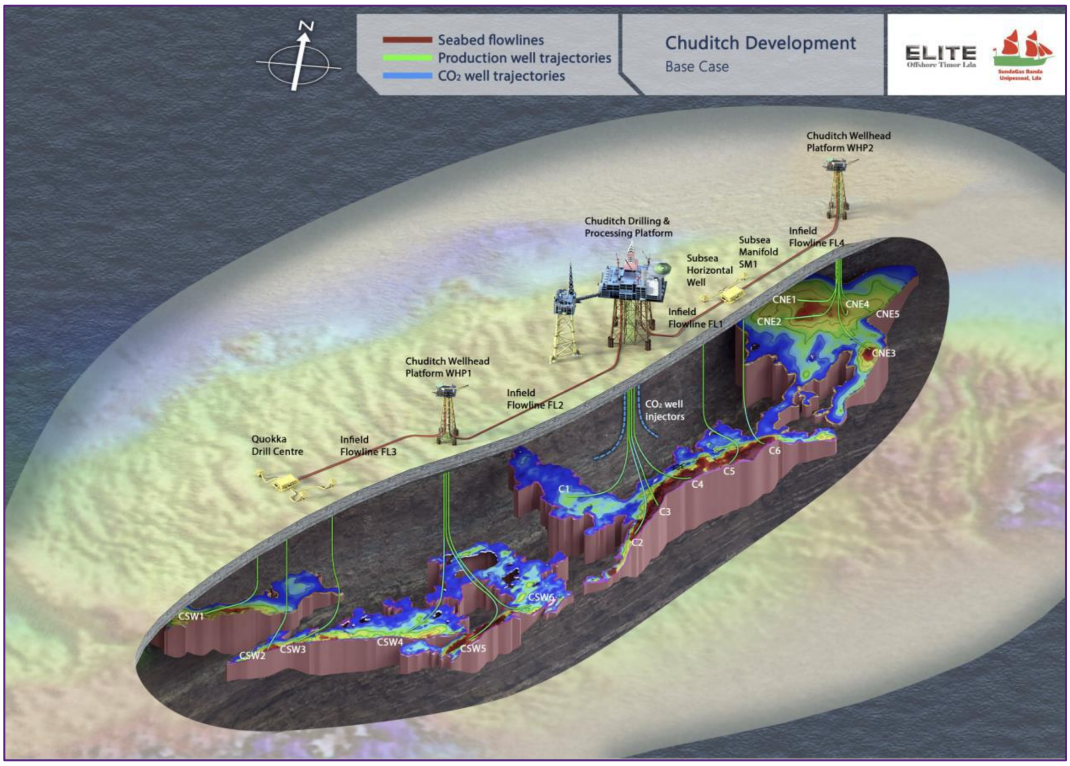

Figure 3.13: Chuditch-1 discovery Infield Facilities

Source: SundaGas

The LNG Development concepts assessed within the scope of the study comprise three scenarios:

- LNG Processing at the Greater Sunrise field, which assumes that all hydrocarbon gas from the Chuditch field is exported to the future Greater Sunrise facilities, with CO_2 separated at Chuditch and CO_2 exported directly to the Bayu Undan field for sequestration or re-injected to the Plover Formation reservoir at Chuditch.
- LNG Processing in Darwin, either via export directly to Darwin (i.e., DLNG or Ichthys LNG) or via an existing/future facility in the region, with CO_2 exported with the hydrocarbon gas for onshore separation and processing.

- Infield LNG production at the Chuditch PSC, either by Floating LNG (FLNG) or via alternate concepts such as Platform LNG (PLNG), with CO_2 again being extracted and assumed exported to the Bayu Undan field for sequestration or re-injected to the Plover Formation reservoir at Chuditch.

The study assessed both technical and commercial aspects which will have impact on the commerciality of Chuditch development.

ERCE is in agreement with the outcome of the study that the concepts with least risk are those that do not rely upon third party facilities.

ERCE considers that re-injection into the reservoir at Chuditch is the most viable and the lower cost option for the field CO_2 management. The option of CO_2 sequestration at Bayu Undan facilities still carries a higher risk due to uncertainty in Bayu Undan project schedule and capacity available for the Chuditch-1 discovery gas.

The high-level project execution schedule is shown in Figure 3.14 which applies to all options.

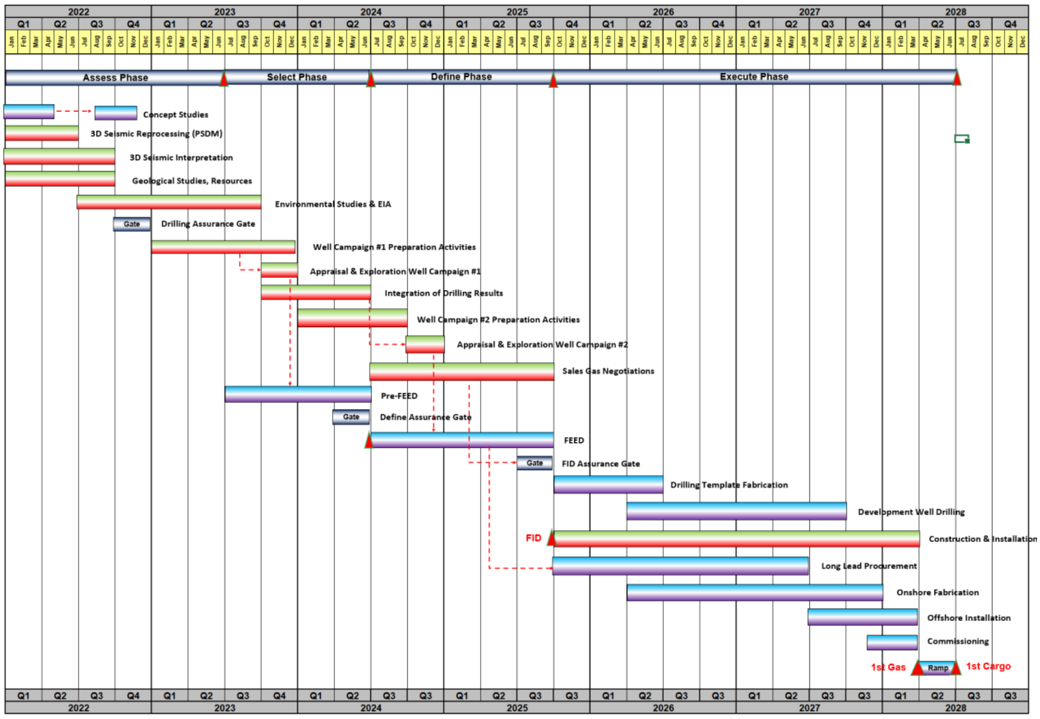

Figure 3.14: Chuditch-1 discovery Development Indicative Schedule

Source: SundaGas

ERCE has reviewed the estimates of 33 months for the execution phase (FID to first gas) and the overall project schedule of 60 months from the concept selection to first gas. ERCE views that a 36-48 month period is a more realistic timeline for the project execution with additional 30-42 month period to complete the pre-FID phases (concept select, pre-FEED and FEED).

Appendix 1: Comparison to SundaGas

At the request of SundaGas, ERCE has also included a summary of SundaGas' volumetric estimates and geological chance of success. Figure 3.1 illustrates SundaGas' High Case thickness above gas water contact for the Chuditch-1 discovery and surrounding prospects.

For the Chuditch-1 discovery, ERCE's P50 GRV is aligned with that obtained from the PSDM derived depth structure by SundaGas. ERCE's Best Estimate GIIP is also similar to that of SundaGas.

SundaGas uses 3D PSDM Top Plover grid for derivation of the Mid Case GRV for the Chuditch-1 discovery and the Chuditch SW prospect. For the two prospects that extend beyond 3D coverage (Chuditch NE and Quokka), SundaGas uses the 3D PSDM volume merged with 2D seismic data. For the prospects, SundaGas' mid case GRV represents a full-to-spill model, with the low and high case GRVs estimated by varying the contact on the PSDM depth grid.

SundaGas' probabilistic GIIP estimates (gross) are summarised in Table A1. Inerts have been removed. SundaGas' Gross Contingent and Prospective Resources estimates, including Geological Chance of Success (COS) are summarised in Table A2.

Table A1 : SundaGas Discovered and Undiscovered GIIP estimates

Discovery	Discovered GIIP (Bscf)				Risk
	Low	Best	High	Mean	COS
Chuditch-1	1230	1628	2127	1659	100%

Prospects	Undiscovered GIIP (Bscf)				Risk
	Low	Best	High	Mean	COS
Chuditch NE	451	1246	1974	1234	34%
Chuditch SW*	613	1234	1802	1222	40%
Quokka	161	560	1039	586	26%

Notes

1. Gross GIIP and Contingent / Prospective Resources include volumes outside TL-SO-19-16 PSC.

* ERCE consider Chuditch SW as two separate prospects (Alpha and Beta).

Table A2: SundaGas Gross Contingent and Gross Prospective Resources estimates

Discovery	Gross Gas Contingent Resources (Bscf)				Gross Condensate Contingent Resources (MMstb)				Risk
	1C	2C	3C	Mean	1C	2C	3C	Mean	COS
Chuditch-1	829	1133	1533	1161	1.9	5.3	12.1	6.3	100%

Prospect	Gross Gas Prospective Resources (Bscf)				Gross Condensate Prospective Resources (MMstb)				Risk
	1U	2U	3U	Mean	1U	2U	3U	Mean	COS
Chuditch NE	311	860	1401	863	1.0	3.6	10.0	4.7	34%
Chuditch SW*	420	852	1284	855	1.2	3.7	9.5	4.6	40%
Quokka	110	388	733	410	0.4	1.6	4.9	2.2	26%

Notes

1. Gross GIIP and Contingent / Prospective Resources include volumes outside TL-SO-19-16 PSC.

* ERCE consider Chuditch SW as two separate prospects (Alpha and Beta).

ERCE's petrophysical parameter ranges used in its probabilistic volumetric calculations are similar to that of SundaGas.

ERCE's recovery factor range of 45% - 62.5% - 70% is based on the results of modelling that considers dominant water drive in the Low and Mid Case, and depletion drive in the High Case. SundaGas' adopt a higher recovery factor range of 60% - 70% - 80%.

SundaGas' and ERCE's COS estimates are similar. However, ERCE modifies certain risk elements for prospects based on our view of trap definition and hydrocarbon migration.

Appendix 2: Net Reservoir and Pay Statistics

Table A3: Net Pay Statistics based on ERCE's Interpretation (VSH ≤ 0.3, PHIT ≥ 0.05, SWT ≤ 0.75) in Chuditch Field

Well	Zone	Top MD	Bottom MD	Gross MD	Net Reservoir	Net Reservoir/ Gross	Net Pay	Net Pay/ Gross	Reservoir Porosity	Pay Porosity	Pay Sh
		m	m	m	mMD	%	mMD	%	%	%	%
CHUDITCH-1	Top Plover Fm Gas	2917.0	2941.0	24.0	20.0	83%	20.0	83%	12%	12%	88%
CHUDITCH-1	Top Plover Fm Water	2941.0	3020.0	79.0	59.4	75%	0.0	0%	9%	---	NA

Notes

1. Well Chuditch-1 reached TD in Plover Fm at 3035 mMD. Log data terminates 15 m short of the well TD.
2. A log derived GDT at 2,941 mMD (2,916 mTVDSS) and WUT at 2,948 mMD (2,923 mTVDSS) are observed in Well Chuditch-1. An FWL at 2,945 mMD (2920 mTVDSS) is estimated from MDT formation pressure measurements.

Appendix 3: Nomenclature

1P	Proved
2P	Proved + Probable
3P	Proved + Probable +Possible
ABEX	abandonment cost
ANPM	Autoridade Nacional do Petróleo e Minerais
API	American Petroleum Institute
Bg	gas formation volume factor, in scf/rcf
BHA	bottom hole assembly
Bo	oil formation volume factor, in rb/stb
Bscf	thousands of millions of standard cubic feet
C&P	cased and perforated
CGR	condensate gas ratio
CIIP	condensate initially in place
CO_2	carbon dioxide
CoP	cessation of production
CPI	computer processed interpretation
CPP	central processing platform
CVD	constant volume depletion
D-N	density-neutron
D&M	Degolyer & McNaughton
DCA	decline curve analysis
DST	drill stem test
Eg	gas expansion factor
EoS	equation of states
FBHP	flowing bottom hole pressure
FDP	field development plan
FEED	front end engineering design
FIT	formation interval test
FMB	flowing material balance
FPSO	floating production storage and offloading
FSO	floating storage and offloading
ft	feet

FTHP	flowing tubing head pressure
FVF	formation volume factor
FWL	free water level
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GOR	gas oil ratio
GR	gamma ray
GRV	gross rock volume
GSA	gas sales agreement
GWC	gas water contact
H_2S	hydrogen sulphide
HIIP	hydrocarbons initially in place
HLV	Heavy Lift Vessel
HPHT	high pressure, high temperature
ICV	interval control valve
JV	joint venture
JPDA	joint petroleum development area
kh	permeability thickness
km	kilometres
Kr	relative permeability
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTC	long term compression
m	metre
M MM	thousands and millions respectively
MBT	Maritime Border Treaty
MD	measured depth
md or mD	millidarcy
MDRKB	measured depth below Kelly Bushing
MDT	modular dynamic tester
MICP	Mercury Intrusion Capillary Porosimetry
MSL	mean sea level

mss	metres subsea
MW	mega watts
N_2	nitrogen
NAG	non-associated gas
NCS	net confining stress
NBP	National Balancing Point
NMR	nuclear magnetic resonance
NOC	national oil company
NPV xx	net present value at xx discount rate
NTG	net to gross ratio
NUI	normally unmanned installation
ODT	oil down to
OPEX	operating cost
OWC	oil water contact
P90	low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
P50	mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
P10	high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)
Pb	saturation, or bubble point, pressure
PHI	porosity
PHIE	effective porosity
PHIT	total porosity
PI	productivity index, in stb/d/psi for oil or MMscf/d/psi or Mscf/d/psi for gas
POD	plan of development
Possible	Possible, as defined in Appendix 4
PP	primary intergranular pores
Probable	Probable, as defined in Appendix 4
Proved	Proved, as defined in Appendix 4
PSA	production sharing agreement
PSC	production sharing contract
PSDM	post stack depth migration
PSTM	post stack time migration
PTA	pressure transient analysis
PVT	pressure volume temperature experiment

QO	quartz overgrowth
RAM	reliability, availability and maintainability
rb	reservoir barrels
RCA	routine core analysis
rcf	cubic feet at reservoir conditions
RESDEEP	resistivity deep
RESMED	resistivity medium
RESSHAL	resistivity shallow
RFT	repeat formation tester
Rs	solution gas oil ratio
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SITHP	shut-in tubing head pressures
SNA	sum of negative amplitudes
ss	sub-sea
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place
SURF	subsea, umbilicals, risers and flowlines
Sw	water saturation
Swc	connate water saturation
SWE	Effective water saturation
SWT	Total water saturation
TD	total depth
THP	tubing head pressure
TVD	true vertical depth
TVDBML	true vertical depth below mud line
TVDSS	true vertical depth sub-sea
TWT	two way time
U&O	Uncertainty and Optimisation
VSH	volume of shale
WGR	water gas ratio
WOR	water oil ratio
WUT	water up to
ZOC	zone of cooperation

Appendix 4: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

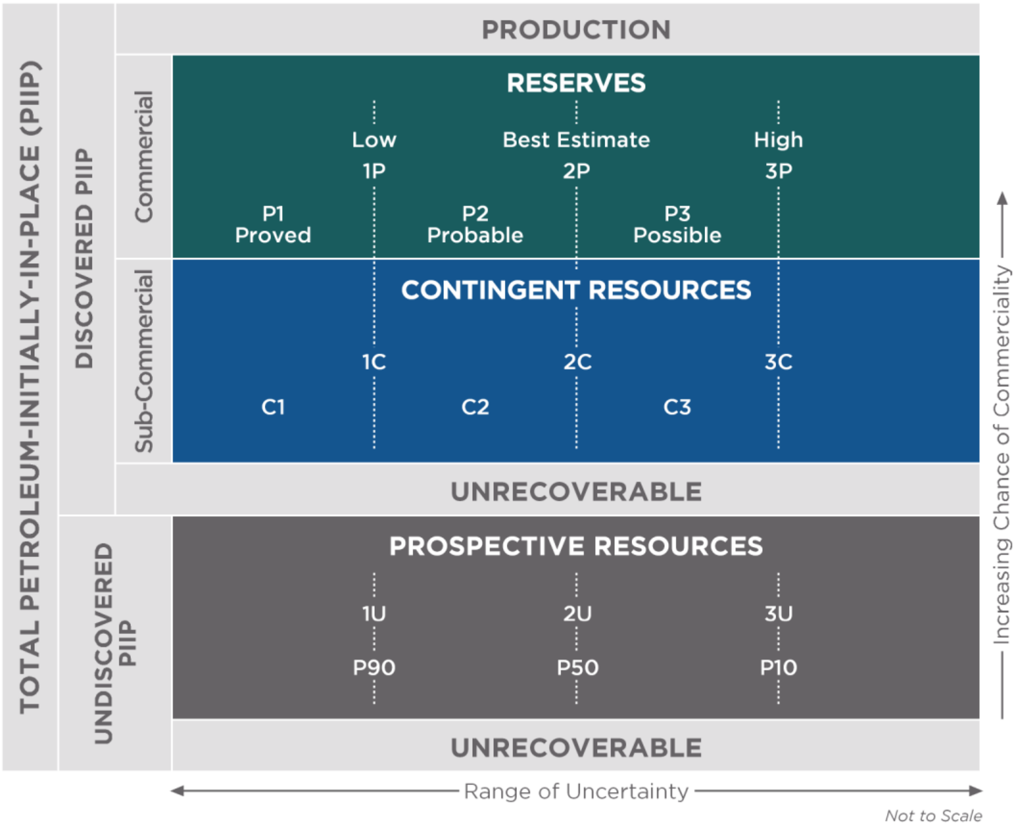

Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

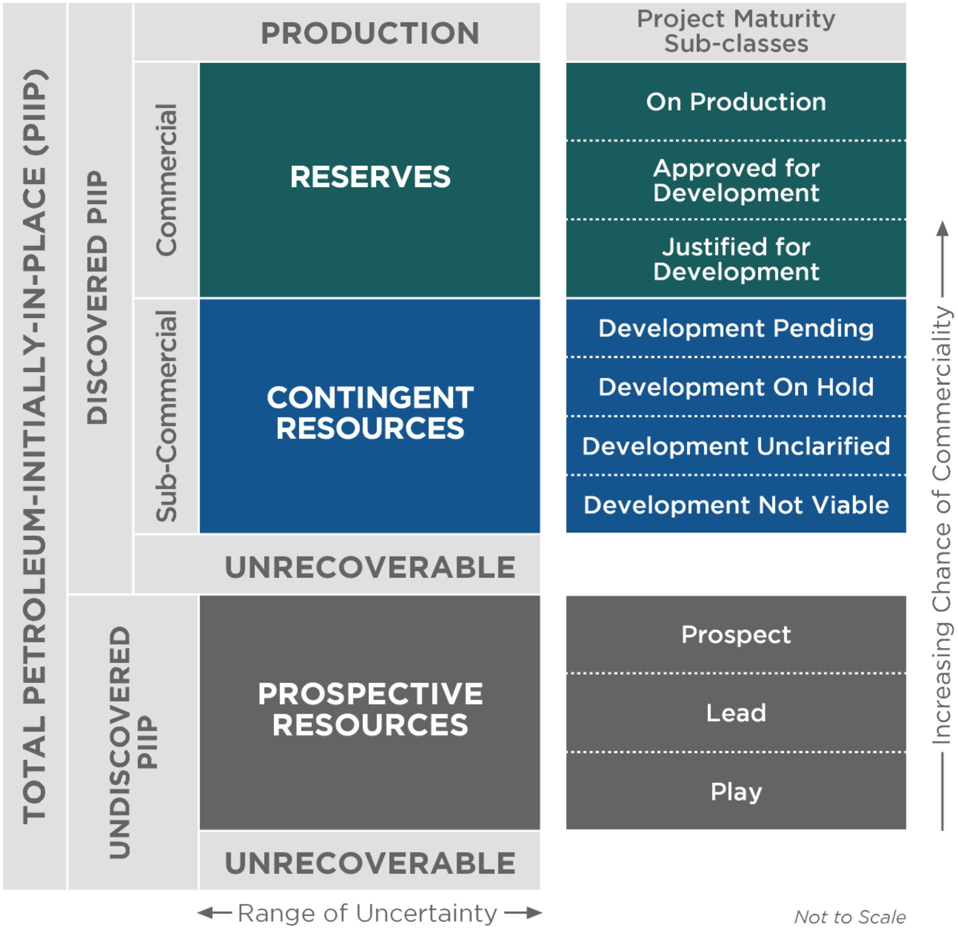

Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market- related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Classes/Sub-classes	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

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

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as “ADR net of salvage.”
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator’s assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.

Assessment	See Evaluation.
Associated Gas	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Basin-Centered Gas	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]

Commercial	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
Committed Project	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)
Completion	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Constant Case	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)

Contingency	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Continuous-Type Deposit	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.
Conventional Resources	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)

Deterministic Incremental Method	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non- Producing.
Developed Producing Reserves	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.

Discovered	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.
Economically Not Viable Contingent Resources	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the determination.
Effective Date	Resource estimates of remaining quantities are "as of the given date" (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date."
Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	Methods of recovery or processing that have proved to be successful in commercial applications.

Estimated Ultimate Recovery (EUR)	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).
Flow Test	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.

Gas Hydrates	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Gas/Oil Ratio	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, Rs ; produced gas/oil ratio, Rp ; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	See Gas Hydrates.
Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	An accumulation that has been discovered.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.

Learning Curve	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
Marketable Quantities	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	The sum of a set of numerical values divided by the number of values in the set.
Measurement	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).
Multi-Scenario Method	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.

Natural Bitumen	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non- hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.
Natural Gas Liquids (NGLs)	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
Non-Hydrocarbon Gas	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non- hydrocarbons.
Oil Sands	Sand deposits highly saturated with natural bitumen. Also called “tar sands.” Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)

On Production	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year- end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Penetration	The intersection of a wellbore with a reservoir.
Petroleum	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	An individual and separate accumulation of petroleum in a reservoir within a field.
Possible Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. 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), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)

Probabilistic Method	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production-Sharing Contract (PSC)	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
Project	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.

Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
Proved Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. 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 a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor’s reimbursement is fixed by the contract’s terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Qualified Reserves Evaluator	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Range of Uncertainty	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).

Reasonable Certainty	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.

Resources Classes	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Risk and Reward	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk Service Contract (RSC)	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.

Split Classification	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as “split classification.” If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as “split conditions.”
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
Sub-Commercial	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cut-off. (See also Technically Recoverable Resources).
Technical Uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.

Tight Gas	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility.Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	Those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	Those quantities of discovered or undiscovered PIIP that are assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Upgrader	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	An entity’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.