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Niels Arveschoug
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North Sea Natural Resources Ltd.
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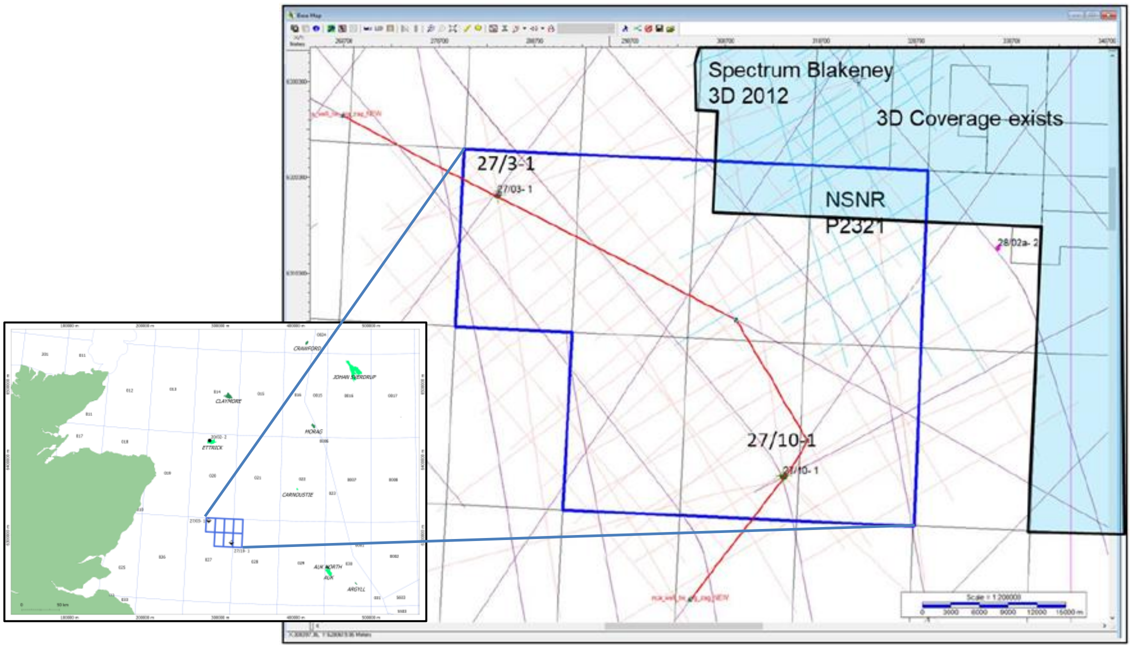
Dear Niels,

Independent Review of Prospective Resources for Devil's Hole Horst, UK Continental Shelf

Introduction

As part of the UKCS 29th Offshore Licensing Round, North Sea Natural Resources Ltd. (NSNRL) was awarded licence P2321 comprising seven blocks (27/3, 27/4, 27/5, 27/9, 27/10, 28/1 & 28/6) on the Mid North Sea High. NSNRL holds a 100% interest in the license. **Figure 1** shows the location of the two legacy wells located on the licence (27/3-1 (drilled in 1967) and 27/10-1 (drilled in 1970)).

Figure 1: P2321 Licence Location, Wells and Seismic Coverage



Source: NSNRL

Based on the existing well and seismic data, NSNRL has identified the Devil's Hole Horst prospect, which comprises several stacked reservoir targets (Leads) in multiple Zechstein dolomites, as well as in Jurassic and Devonian sandstones. At the request of NSNRL, Gaffney, Cline & Associates (GCA) has performed an independent review of the Prospective Resource estimates for the each of the Leads identified by NSNRL.

This review has considered all the subsurface elements that are required to make the volumetric estimates for each of the reservoir targets identified by NSNRL, and included a review of the seismic interpretation, mapping of the structure (in time and depth) and the methods used to estimate the range of gross-rock volumes used in the preparation of the resource estimates. A review was also conducted of the net reservoir parameters used in the calculations.

GCA conducted a review and discussion of the seismic interpretations, mapping and the parameters used in the estimates in a one (1) day workshop with the NSNRL interpreters. This was followed by an independent assessment of the range of volumetric estimates for each reservoir target and its associated Geological Chance of Success (GCoS).

The review relied on the seismic interpretations and resulting depth structure grids/maps provided by NSNRL to GCA. The review was conducted over a two-week timeframe. No independent interpretation of the seismic, time to depth conversion or depth mapping was performed. A petrophysical interpretation of the 27/10-1 well logs over the Zechstein interval was conducted by GCA in a previous study and a quicklook interpretation of the Zechstein interval in the 27-3-1 well was also conducted by GCA for this review. The results from these analyses have been used together with a review of the analyses conducted by NSNRL for other reservoir intervals to define the ranges of reservoir parameters applied in the resource volume estimates reported herein.

Resource estimates have been prepared in accordance with the SPE Petroleum Resource Management System (PRMS) Definitions and Guidelines (as updated in 2018).

This report relates specifically and solely to the subject matter as defined in the scope of work (SOW), as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

Summary and Conclusions

The Devil's Hole Horst is located in the P2321 licence and lies approximately 120 km offshore on the Mid North Sea High in the UK North Sea. The licence covers an area of approximately 1,750 km^2 in water depths of ~75 m.

NSNRL has mapped four structures in the block and estimated their Prospective Resources and associated GCoS. GCA has reviewed data and interpretations provided by NSNRL in order to provide an independent assessment of Prospective Resources and GCoS using an audit approach.

In its review GCA has determined the identified structures should be classified as Leads as interpretation refinement is ongoing and a new seismic survey is planned to be acquired as part of the work commitments on the block, and will be necessary before any drilling commitment is made.

It is GCA's opinion that the estimates of total recoverable hydrocarbon liquid volumes, as of 30th November 2019, summarised in **Table 1**, are reasonable, the Resources classification and categorization as Prospective Resources is appropriate and consistent with the definitions and guidelines for Resources.

Table 1: Gross Oil Prospective Resources for Licence P2321 (Devil's Hole Horst)

Lead/Reservoir	Oil Prospective Resources (MMstb)				GCoS
	Low	Best	High	Mean	
Jurassic	524	1,081	2,209	**1,259**	0.21
Zechstein Z3	6.0	24.7	73.0	**34**	0.49
Zechstein Z1/Z2	84	290	858	**408**	0.18
Devonian	4.3	10.2	24.3	**13**	0.13

Notes:

1. Gross Prospective Resources are 100% of the on-block volumes estimated to be recoverable from the Leads in the event that a discovery is made and subsequently developed.
2. The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery (GCoS) and a risk of development (chance of a commercial development). Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.
3. The volumes reported here are "Unrisked" in the sense that the GCoS factor has not been applied to the designated volumes within this assessment.
4. Leads are features that are not sufficiently well defined to be drillable, and need further work and/or data.
5. The GCoS reported here represents an indicative estimate of the probability that drilling the Lead would result in a discovery, which would warrant the re-classification of those volumes as a Contingent Resource.
6. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Lead and the potential dependencies between them.

Discussion

1 Database

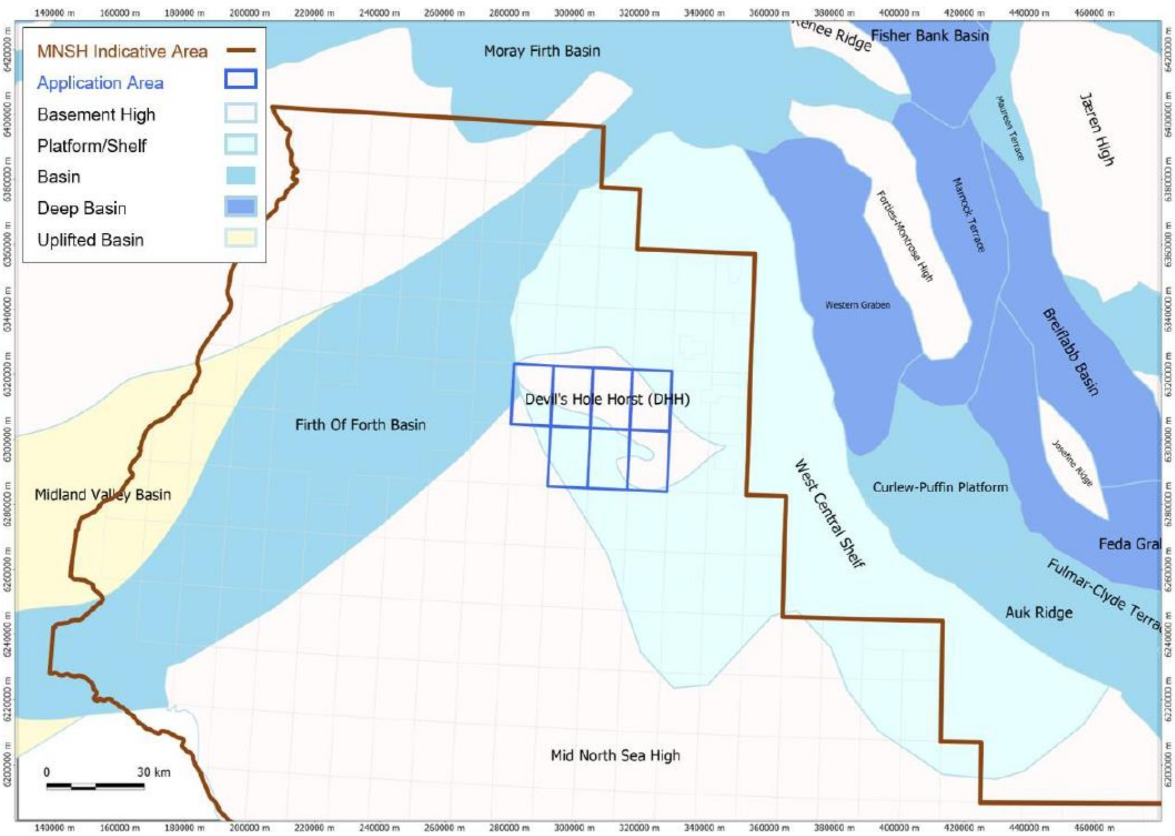
Seismic data over the P2321 license interpreted and mapped by NSNRL for this review includes over 3,000 km of 2D seismic including 2015/2016 WesternGeco seismic survey made available by the UK government OGA, supplemented with 2004 TGS spec data, 1990 Fina data, a 1988 BP survey, licensed 1980's WesternGeco data and the original 1960's Amoco data.

Well data available to NSNRL included logs, core and well reports from the two wells drilled within the licence area and from 8 other key OGA released wells from the surrounding area (20/20-2, 20/12-3, 26/4-1, 26/7-1, 26/8-1. 26/12-1, 26-14-1 and 28/12-1).

2 Regional Geology and Petroleum System

The licence area is situated on the Mid North Sea High (MNSH), some 70 km to the west of the prolific oil and gas province of the West Central Graben of the UKCS, and also some 30 km to the west of the West Central Shelf (**Figure 2**). The present day structural framework is a result of prolonged extension from the Carboniferous to the Early Cretaceous, coupled with thermal subsidence during the Cretaceous and Tertiary.

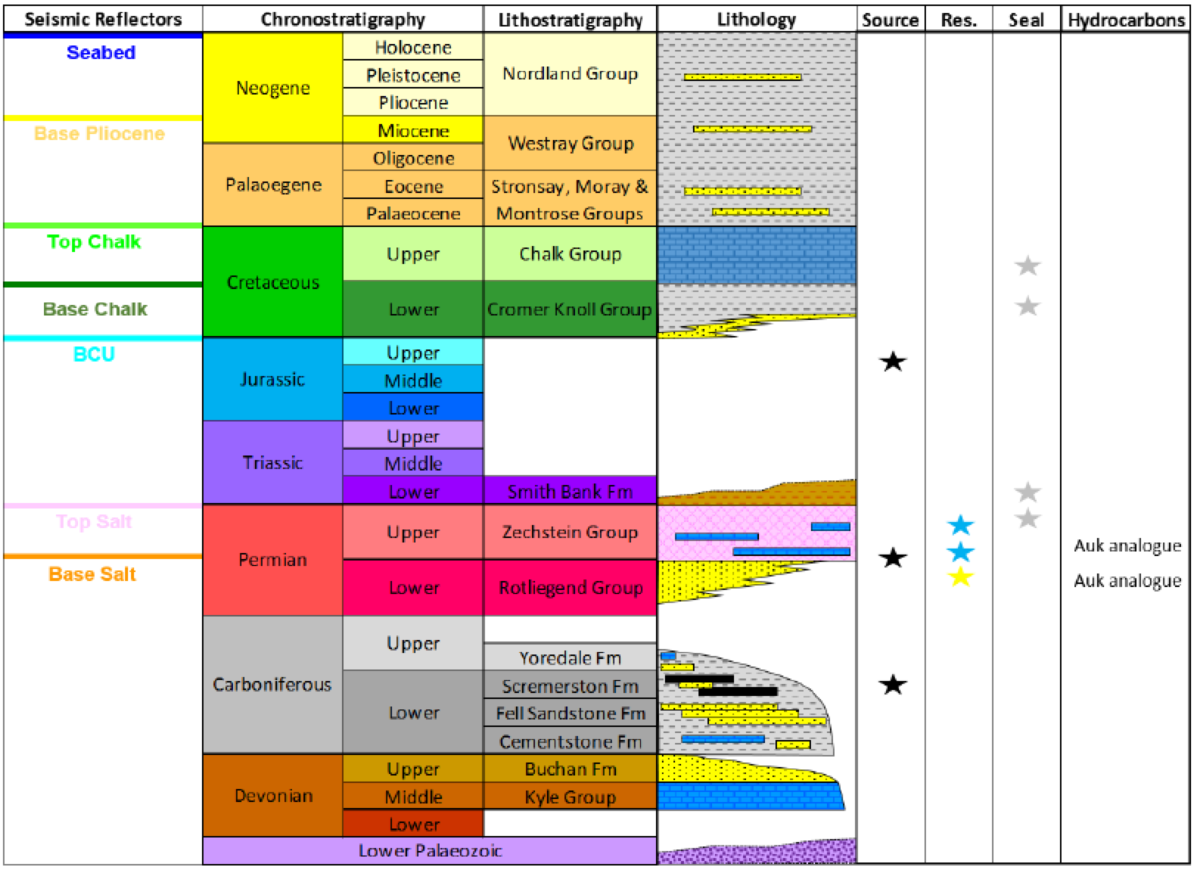
Figure 2: Devil's Hole Horst Structural Setting



Source: NSRL Licence Application

The Devil's Hole Horst is believed to have originated during the Variscan orogeny in the Late Carboniferous to Early Permian, at the time of general uplift of the MNSH. Lower Palaeozoic basement is penetrated in both wells beneath later Devonian clastic sediments and Permian Zechstein deposits. No Carboniferous sequences have been penetrated over the horst.

Figure 3: Stratigraphic Column for License Area showing Petroleum System Elements



Source: NSNRL License Application (GCA modified)

2.1 Source Rocks

Following the award of the P2321 license NSNRL has commissioned a Fluid Inclusion Stratigraphy (FIS) and regional petroleum geochemistry study (Integrated Geochemical Interpretation Ltd, 2019) to identify and type the hydrocarbon fluids in the DHH area. Cuttings and core samples from the two wells, 27/3-1 and 27/10-1, were analyzed for FIS screening for the potential presence of hydrocarbon fluids. Additionally, petroleum inclusions were extracted for biomarker analyses from one interval of the Zechstein Z2 Dolomite in 27/3-1 and from one interval from the Zechstein Z1 Dolomite in 27/10-1.

A regional petroleum geochemistry study of the area surrounding the DHH was performed based on full analysis of 23 oil and gas condensate samples from wells in the area in order to identify the main oil families in the region and for typing, by oil-oil correlation, of the DHH petroleum fluid inclusions.

In well 27/10-1, the FIS study identified a proximity to wet gas in the Permian Zechstein Z2 Dolomite and to liquid petroleum in the Z1 Dolomite interval. In well 27/3-1, the FIS study also found evidence of some amount of oil charge in the Permian Z2 Dolomite interval, and several intervals of proximity to wet gas were detected in Devonian sand formations, in which separate charges of thermogenic gas are suspected.

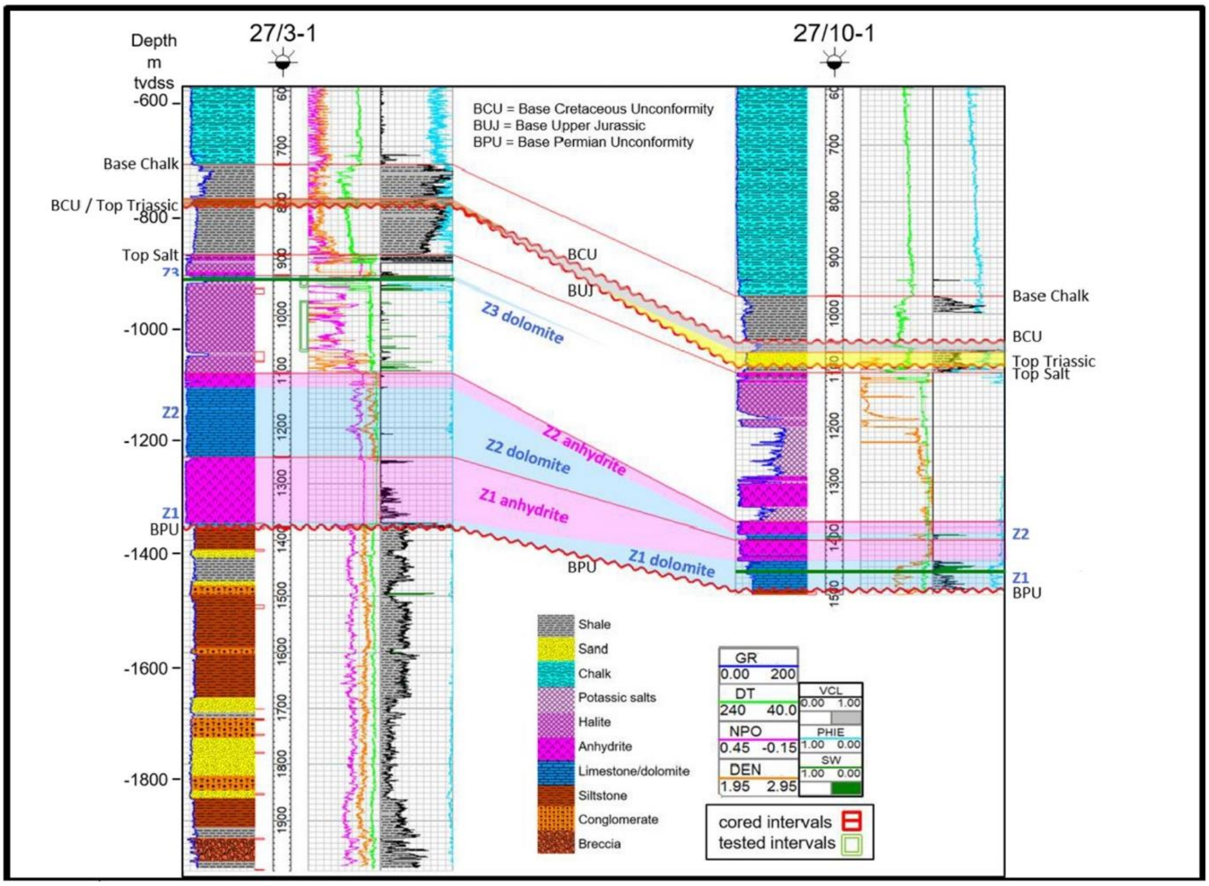
The regional petroleum geochemistry study identifies the petroleum encountered in Permian Dolomite intervals of the DHH to have been sourced from the Upper Jurassic Kimmeridge Clay Formation (KCF), with the kitchen probably located in the East Central Graben. However, the authors also hypothesize that the thermogenic gas in the Devonian sands in 27/3-1 might be charged from Carboniferous sources (presumed from the Forth Approaches Basin to the north)

In the Z1 Dolomite reservoir of well 27/10-1, the slightly more sulphur-rich character of the fluid suggests that it might contain some contributions from a more restricted facies in the KCF kitchen. The occurrence of hydrocarbon gases consistent with KCF sources in Z3 Permian Dolomite intervals of well 26/4-1, which is located west of the DHH in the Forth Approaches Basin, supports evidence for the occurrence of petroleum that has migrated laterally from Central Graben kitchens into Permian reservoirs of the DHH in the Mid North Sea High.

2.2 Reservoirs

The main reservoir targets consist of Z1 and Z2 carbonate, mainly dolomite, intervals within the Permian age Zechstein Group sequences and the shallower good quality Upper Jurassic age sands. Secondary targets are the thin Z3 dolomite and deeper Devonian age sandstones. These four target reservoirs are shown in a well correlation between the 27/3-1 and 27/10-1 wells (**Figure 4).**

Figure 4: DHH 27/3-1 and 27/10-1 Well Correlation



Source: NSNRL Information Memorandum

2.3 Seals

Regional seals are provided by the Lower Cretaceous and Upper Jurassic shales, which could act as seals for the Jurassic target structure. Zechstein evaporate sequences (Salt and Anhydrite) provide top and base seals for the Zechstein carbonates as well as providing potential seal for the deeper Lower Devonian sand target.

2.4 Traps

In the Upper Jurassic Lead the trapping mechanism is stratigraphic, the closure is dependent on up-dip thinning and pinch out of the reservoir. The Zechstein targets (Z3 and Z1/Z2) include combined structural and combined structural/stratigraphic traps with structural components comprising four-way dip closure as well as horst blocks, which rely on fault closure. Lateral facies changes in the Zechstein evaporates/carbonates provide the potential for stratigraphic trapping as demonstrated by the difficulty in correlating reservoir intervals between the 27/3-1 and 27/10-1 wells and in the variable quality in reservoir properties. In the Devonian a four-way dip closed structural trap is mapped sub-cropping the Base Permian Unconformity.

2.5 Charge/Timing

An Oil Migration study *"Modelling of the Petroleum Systems of the Devil's Hole Horst, Mid North Sea High (Quadrant 27, UKCS)"* (Integrated Geochemical Interpretation Ltd., 2019) commissioned by NSNRL has reported the following key findings:

- It postulates "..*that pre-Zechstein carrier beds have been charged with petroleum expelled from Upper Jurassic source intervals where they are juxtaposed at main rift-bounding faults."*
- It *"predicts that Upper Jurassic source intervals have only reached oil-window maturities in the West Central Graben areas, excluding the hypothesis that oil inclusions in Permian dolomites in wells 27/3-1 and 27/10-1 in the DHH could have been expelled from incipient local generation at any time."*
- Several simple migration scenarios assuming a strong top-seal of 500 m (for Zechstein evaporites) and a 20 m thick pre-Zechstein carrier bed are reported. The model predicted that…
    - *If minor migration losses of 5 mmboe km^{-2} are assumed, the model predicts an oil charge of over 11 Billion bbl in the DHH, which is forecasted to have been charged essentially since the late Cenozoic.*
    - *…the model still predicts a total oil charge of over 1.7 Billion bbl for unrealistically large migration losses of 80 mmboe km^{-2}*.

However, the report also identified two main risk factors for the DHH petroleum system:

- *"Charging of pre-Zechstein carrier beds with KCF petroleum at the graben-platform contact."*
- *"Non-interrupted migration of the hydrocarbon fluids towards the culminating DHH area".*

Although the study is encouraging, there are still a number of risk factors that would need to be addressed before the charge model for all the structures mapped over the DHH can be validated.

3 Devil's Hole Horst Resource Estimates

NSNRL has identified four Leads within the P2321 license, which comprise reservoir target intervals in Jurassic sands, Zechstein dolomites and Devonian sands.

The four structures have been mapped on the license by NSNRL using a relatively sparse grid (~ 3.5km spacing) of 2D data acquired in several surveys shot between the early 1960's and 2015. The data quality is variable and there are differences in acquisition and processing parameters between the surveys which, not unexpectedly, results in variations in reflector strength and difficulties in tying all the surveys and picking consistent reflectors. However, NSNRL has worked to adjust the seismic to minimise the mis-ties and the resulting dataset is considered reasonably robust.

None of the structures is considered to be 'Drill Ready' and NSNRL plans to acquire 3D seismic over the area to better define each target and reduce risks before any well is drilled. Based on PRMS definitions, all four targets are classified as Leads.

GCA was provided with estimates of in-place and recoverable volumes by NSNRL for each of the Leads. GCA has reviewed each of the structures and has estimated its own in-place and recoverable volumes for the Leads. In general, the GCA estimates are lower than those provided by NSNRL. However, GCA considers that its volumetric estimates are reasonable when considered in conjunction with the recent Oil Migration study commissioned by NSNRL, which estimated the range of hydrocarbon volumes that potentially, could have been expelled from the source rocks in the West Central Graben source kitchen and migrated into the Devil's Hole Horst area.

A Monte Carlo model was used to estimate the in-place and Prospective Resources for each of the Leads. Input to the Monte Carlo model was based on the reservoir maps provided by NSNRL with hydrocarbon extents revised by GCA in consideration of the structural and stratigraphic controls relating to each Lead. Maps and details of the limits used by GCA to estimate the Low and High case Gross Rock Volumes (GRVs) are provided in the description of each lead in the following sections. Reservoir parameters were based on those provided by NSNRL adjusted, where necessary to reflect GCA's review/interpretation of the well log data provided for the two wells on the license. Details of the input GRV and reservoir parameter distributions are provided for each Lead in **Appendix III**.

GCA has also estimated a GCoS for each Lead based on the chance of finding the estimated hydrocarbon volumes that can flow to surface. The calculation of the GCoS uses a matrix approach for each of five factors:

- Trap and Seal;;
- Reservoir presence and quality;
- Hydrocarbon source (presence, quality, maturity and migration);
- Geological timing; and
- Play factor.

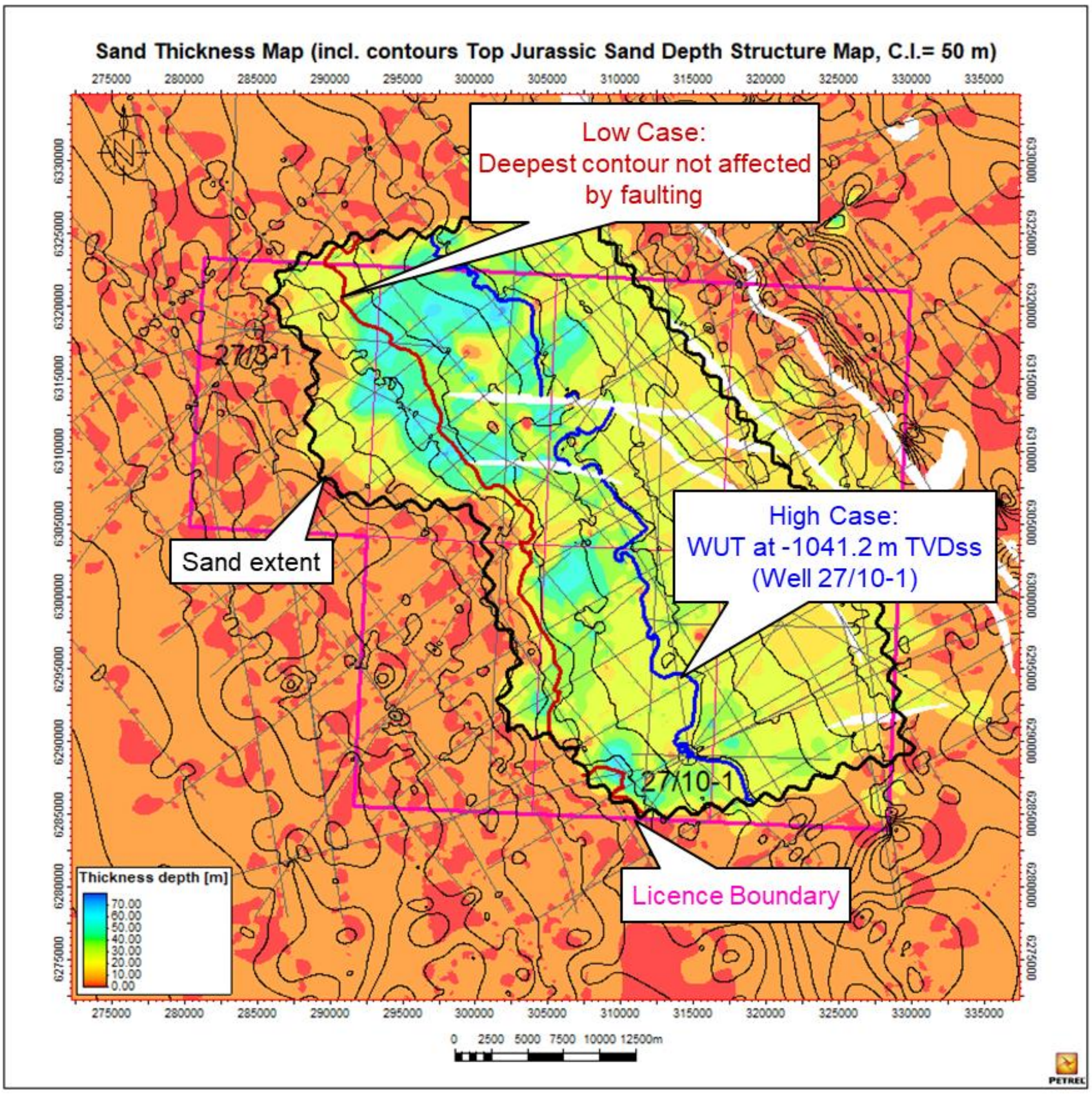
The overall GCoS is estimated by the multiplication of the specific values from each of the five factors. The GCoS estimate helps to provide a numerical ranking system for the leads and highlights the most significant risks associated with each lead. This allows for the identification of areas where more data, analysis or a better understanding may help to de-risk a lead. The Leads have all been assessed with a Moderate GCoS.

A summary description of each Lead is provided in the following sections.

3.1 Jurassic Sandstone Lead

The Jurassic Sandstone Lead is a combination trap, defined by sand pinch-out to the north, south, and west and a dip closure to the east/northeast. The crest of the structure is mapped at - 800 m TVDss. The reservoir is penetrated in the 27/10-1 well where the reservoir is water wet; the Jurassic sandstones is not present in the 27/3-1 well but can be mapped using the sparse seismic data as extending over much of the license area. The sands are mapped as pinching out in a south-westerly direction and also thinning in a north-easterly direction towards the source kitchen **(Figure 5**). Sand thickness, where present, varies over the licence with a thickness up to a maximum of about 70m.

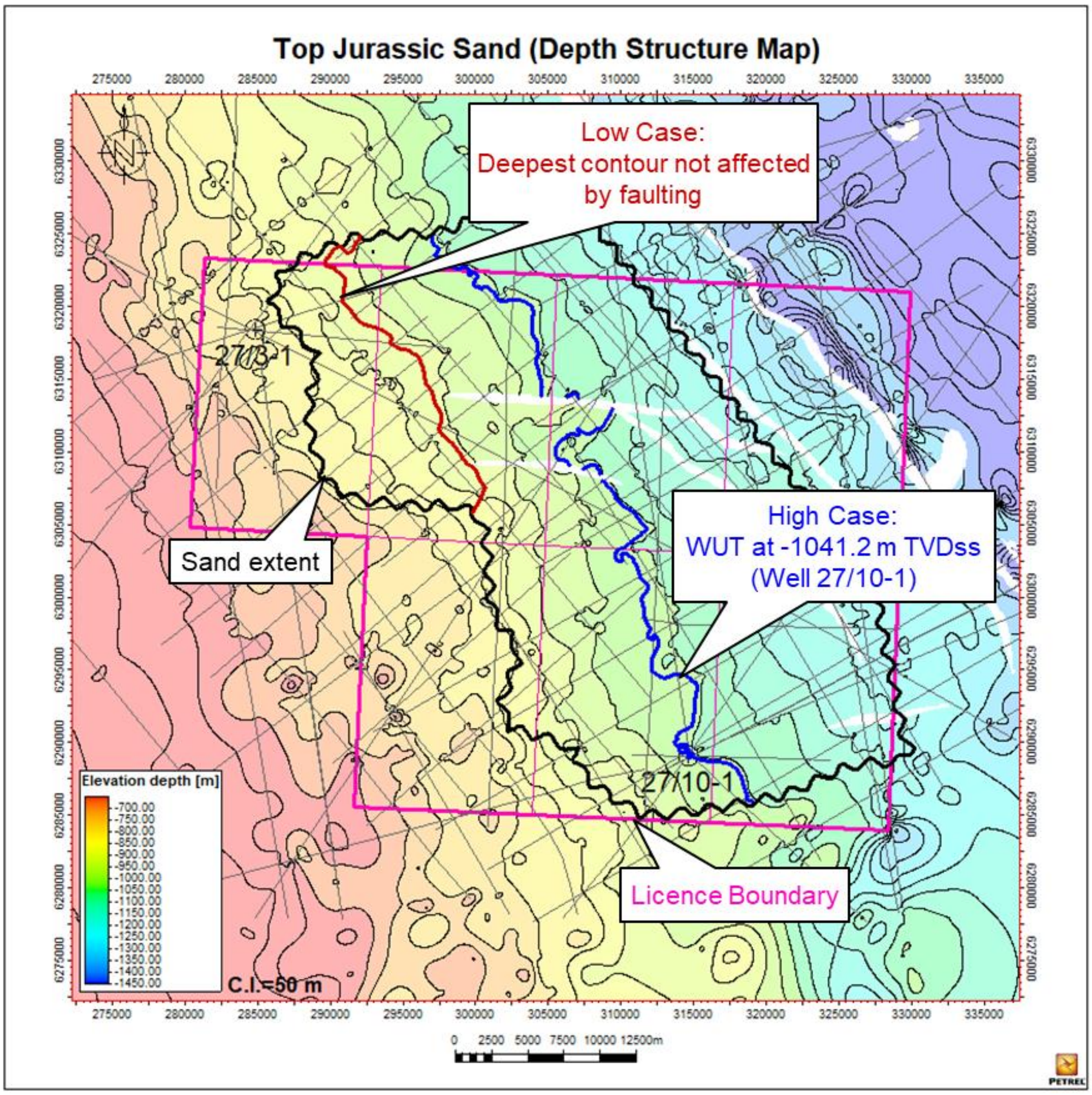
Figure 5: Jurassic Lead Mapped Reservoir Thickness



Source: GCA based on digital data provided by NSNRL

The water-up-to (WUT) depth in Well 27/10-1 at -1,041.2 m TVDss was used to define the maximum closure area. The low case closure area was selected as the lowest up-dip closing contour that is not intersected by faults. **Figure 6** presents a depth structure map of the top Jurassic Sandstone, showing interpreted sand extent, as well as the depth contours used to define the Low and High Case GRV estimates.

Figure 6: Top Jurassic Sand Depth Structure Map



Source: GCA based on digital data provided by NSNRL

GCA's estimates of oil in place for the Jurassic Lead are summarised in **Table 2**, detailed parameters used as input to the Monte Carlo model are given in **Appendix III**.

Table 2: GCA Estimate of Oil In-Place Volumes for Jurassic Lead

	Oil In-Place (MMstb)		
Lead/Reservoir	**P90**	**P50**	**P10**
Jurassic	1,332	2,714	5,485

The main subsurface risks are summarised below:

- Trap – pinch-out effectiveness and leakage along fault planes are key risks. The stratigraphic trap has been mapped by NSNRL on relatively wide spaced 2D seismic data and consequently the definition of the up-dip pinch out and the extent and mapping of faults carries a significant risk. As such, GCA has limited the Low Case extent of the structure to the deepest closing contour, not affected by major faulting.

- Other risks are sand distribution and charge. Sand thickness is mapped as being variable and thinning both towards up-dip pinch-out and towards the source graben. The latter, therefore, has the potential to restrict migration pathways from the source kitchen, which assumes that the reservoirs act as a carrier bed providing the means for petroleum accumulation into the structure.

Table 3: GCA Estimate of GCOS for Jurassic Sandstone Lead

Migration	Reservoir	Trap	Seal	Play	GCoS
0.65	0.65	0.65	0.75	1.0	0.21

3.2 Permian (Z3) Dolomite Lead

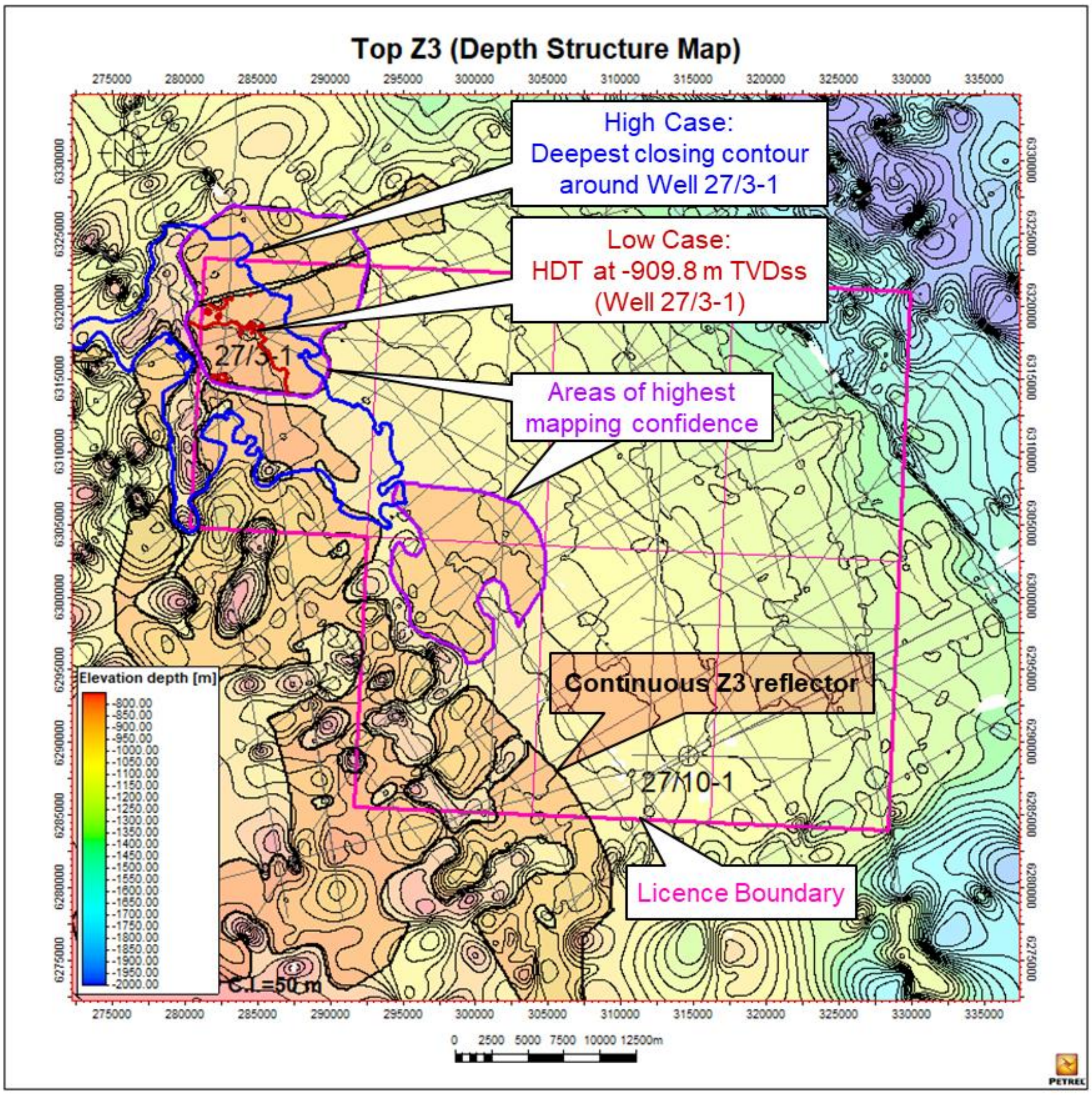
The Permian Z3 Dolomite Lead is a structural trap, with 4-way dip closure. The crest of the structure is located at - 860 m TVDss. The Z3 Dolomite Lead consists of a thin (~5m) dolomite layer, encased within evaporite deposits, which may not be continuous over the whole structure. The interval is interpreted to be oil bearing on logs, but did not flow when tested. The Permian Z3 reservoir was not encountered by Well 27/10-1.

Log analysis of the Z3 interval in well 27/3-1 shows average porosity of around 24% with average water saturation of 23%. Elevated gas readings and live oil trace fluorescence are recorded on the mudlog immediately below the zone. Separation between the Density and Neutron logs and cross-plots of all three porosity logs (Density, Neutron and Sonic) suggest that the hydrocarbons present are more likely to be gas than oil. The hydrocarbon-down-to (HDT) depth in the well at - 909.8 m TVDss. defines the minimum extent of the closure area.

Two open-hole DSTs were performed over the interval 930.9 to 951.3 m MD, which includes the Z3 reservoir section, but no flow of oil or gas is reported in the end of well report. Log data, mudlog readings and results of the fluid inclusion study support a working petroleum system. There are also similarities with nearby proven Zechstein reservoirs (e.g. Auk, Ettrick (Jarvis) and Argyll). However, based on the considerable uncertainty in the information presented, GCA does not consider that there is sufficient justification to classify the Z3 interval in the 27/3-1 well as a discovery.

Figure 7 is a depth structure map of the top Z3 interval, showing the limits used by GCA to estimate the Low and High Case GRV estimates. Reservoir properties used in the Monte Carlo model were based on results from GCA's review of the 27/3-1 well logs. GCA's estimates of oil in place for the Z3 Lead are summarised in **Table 5**, detailed parameters used as input to the Monte Carlo model are given in **Appendix III**.

Figure 7: Top Z3 Depth Structure Map



Source: GCA based on digital data provided by NSNRL

Table 4: GCA Estimate of Oil In-Place Volumes for Zechstein Z3 Lead

	Oil In-Place (MMstb)		
Lead/Reservoir	**P90**	**P50**	**P10**
Zechstein Z3	75	180	435

The key subsurface risks are hydrocarbon type, reservoir presence and quality. The reservoir interval is thin (~5m) and its extent cannot be accurately mapped using the available 2D seismic data. This presents a risk in trap integrity away from the immediate vicinity of the 27/10-1 well. Reservoir quality within the Zechstein has been demonstrated to be variable and although hydrocarbons have been identified on logs, the interval did not flow on test and although this may have been due to plugging of the formation with cement, reservoir deliverability is unknown.

GCA’s estimate of GCoS is provided in **Table 5**.

Table 5: GCA Estimate of GCoS for Z3 Dolomite Lead

Migration	Reservoir	Trap	Seal	Play	GCoS
1.0	0.65	0.75	1.0	1.0	0.49

3.3 Permian (Z1/Z2) Dolomite Lead

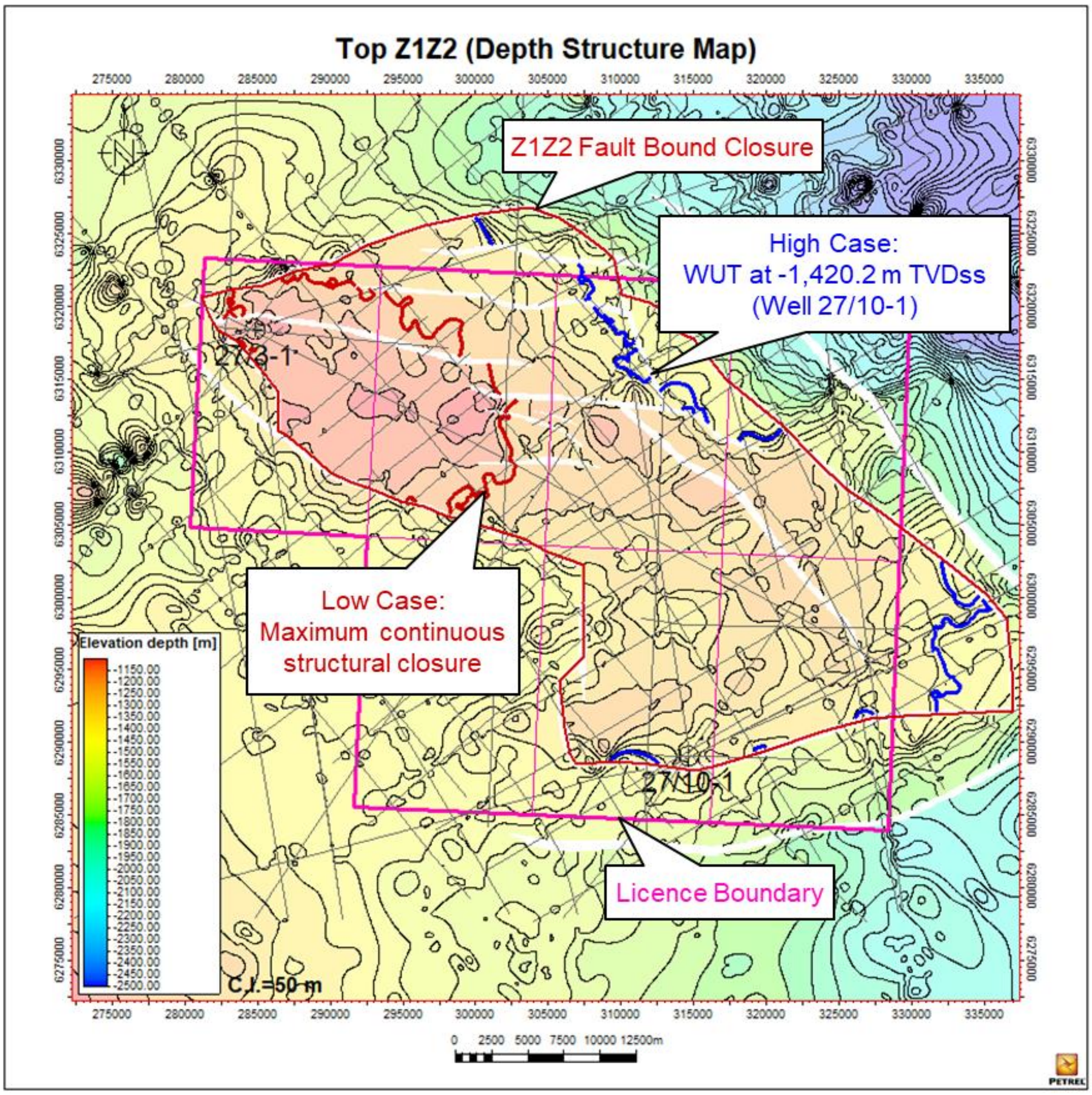
The Permian Z1/Z2 Dolomite Lead is a structural trap, combining 3-way dip and fault closure. The crest of the structure is located at -1,060 m TVDss. The Z1 dolomite is present in 27/10-1 where it is ~170 metres thick with a high Net/Gross (~88%) and has good reservoir porosity (~15%) but is water wet; Z1 is not present in the up-dip 27/3-1 well. The Z2 interval is some 60 metres thick in 27/3-1 but is tight with very low porosity (<5%). It is correlated between the two wells but thins to the east to a net thickness of only about 11 metres in the 27/10-1 well. Reservoir properties are better in this well with average porosity of about 10%. Analysis of the well logs suggests that the interval is water filled.

The individual dolomite intervals cannot be reliably mapped using the 2D seismic data. To define the Lead, NSNRL has used the combined interval from the top of the Z2 Anhydrite to the base of the Zechstein, which is co-incident with the Base Permian Unconformity (see **Figure 4**). The interval comprises a thick sequence of Zechstein Salt, Anhydrite and carbonates with the dolomite intervals (representing 15 – 51% of the interval) interspersed within the mainly salt facies providing the main reservoirs. Net/Gross of the unit is consequently low (~15%) and individual dolomite intervals may not be laterally continuous.

The water-up-to (WUT) depth in well 27/10-1 at - 1,420.2 m TVDss was used to define the maximum closure to the northwest of the structure; closure in the south, north and west is provided by faults. The low case closure was limited to the area around the crest of the structure in the northwest of the license that is approximately defined by the mid-point depth between the crest of the structure and the WUT depth (**Figure 8**).

A depth structure map of the top Z1/Z2 interval, including extent of the tilted fault block, as well as the limits used for the Low and High Case GRV estimates, is shown in **Figure 8**. Reservoir properties used in the Monte Carlo model were based on results from GCA’s review of the 27/3-1 well logs. GCA’s estimates of oil in place for the Z1/Z2 Lead are summarised in **Table 7**Table 5, detailed parameters used as input to the Monte Carlo model are given in **Appendix III**.

Figure 8: Top Z1/Z2 Depth Structure Map



Source: GCA based on digital data provided by NSNRL

Table 6: GCA Estimate of Oil In-Place Volumes for Zechstein Z1/Z2 Lead

	Oil In-Place (MMstb)		
Lead/Reservoir	**P90**	**P50**	**P10**
Zechstein Z1/Z2	591	1,759	4,662

The crestal Well 27/3-1 encountered a tight Z1/Z2 interval. As such, the main subsurface risks are reservoir quality as well as continuity. Another key risk is trap effectiveness and leakage along fault planes.

GCA's estimate of GCoS is provided in **Table 7**.

Table 7: GCA Estimate of GCOS for Z1/Z2 Dolomite Lead

Migration	Reservoir	Trap	Seal	Play	GCoS
0.75	0.50	0.75	0.65	1.0	0.18

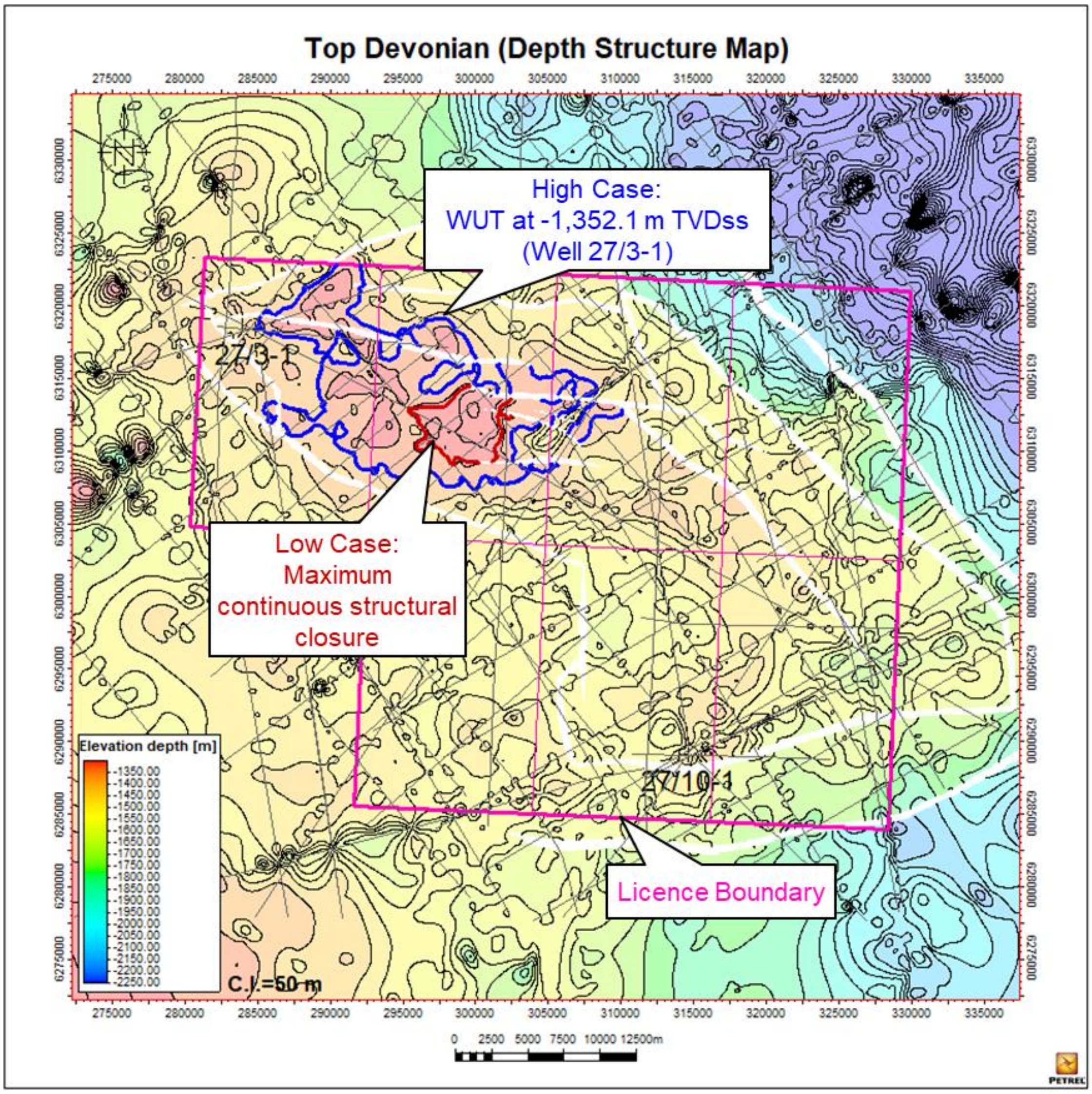
3.4 Lower Devonian Sandstone Lead

The Lower Devonian Sandstone Lead is defined by a structural (4-way dip) closure, sub-cropping the Base of the Zechstein Salt (Base Permian Unconformity). The crest of the structure is located at -1,200 m TVDss. Neither well 27/3-1, nor well 27/10-1 recorded hydrocarbons at this level, based on the End of Well Reports (EOWR). As such, the water-up-to (WUT) depth is defined by Well 27/3-1 at -1,352.1 m TVDss. This has been used to define the maximum closure area for estimating resource volumes. The low case closure has been limited to the maximum continuous structural closure that is not affected by faulting.

The reservoir interval encountered in 27/3-1 is has very low porosity (<4%). No shows have been recorded in the Devonian interval considered as the target reservoir.

Figure 9 presents a depth structure map of the top Devonian, including depth contours for the Low and High Case estimate. Reservoir properties used in the Monte Carlo model were based on results from GCA's review of the 27/3-1 well logs. GCA's estimates of oil in place for the Devonian Lead are summarised in **Table 8**Table 5, detailed parameters used as input to the Monte Carlo model are given in **Appendix III**.

Figure 9: Top Devonian Depth Structure Map



Source: GCA based on digital data provided by NSNRL

Table 8: GCA Estimate of Oil In-Place Volumes for Zechstein Lower Devonian Lead

	Oil In-Place (MMstb)		
Lead/Reservoir	**P90**	**P50**	**P10**
Lower Devonian Sand	18	41	96

The Key subsurface risks are migration and reservoir presence and quality. Secondary risks include seal and hydrocarbon type.

GCA's estimate of GCoS is shown in **Table 9**.

Table 9: GCA Estimate of GCOS for Lower Devonian Sandstone Lead

Migration	Reservoir	Trap	Seal	Play	GCoS
0.55	0.50	0.65	0.75	1.0	0.13

3.5 Prospective Resources

GCA has performed an independent volumetric estimate of the Prospective Resources and assessed the Geological Chance of Success (GCoS) of four leads identified by NSNRL in the offshore UK North Sea license P2321.

GCA has reviewed data and interpretations provided by NSNRL in order to provide an independent assessment of Prospective Resources and GCoS using an audit approach.

In its review GCA has determined the identified structures should be classified as Leads as interpretation refinement is ongoing and a new 3D seismic survey is planned to be shot as part of the work commitments on the block before any drilling commitment is progressed.

It is GCA's opinion that the estimates of total recoverable hydrocarbon liquid volumes, as of 30th November 2019, are as summarised in **Table 10**.

Table 10: GCA Estimate of Prospective Resources for for License P2321 (Devil's Hole Horst)

Lead/Reservoir	Oil Prospective Resources (MMstb)				GCoS
	Low	Best	High	Mean	
Jurassic	524	1,081	2,209	**1,259**	0.21
Z3 Dolomite	6.0	24.7	73.0	**34**	0.49
Z1/Z2 Dolomite	84	290	858	**408**	0.18
Devonian	4.3	10.2	24.3	**13**	0.13

Notes:

1. Gross Prospective Resources are 100% of the on-block volumes estimated to be recoverable from the Leads in the event that a discovery is made and subsequently developed.
2. The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery (GCoS) and a risk of development (chance of a commercial development). Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.
3. The volumes reported here are "Unrisked" in the sense that the GCoS factor has not been applied to the designated volumes within this assessment.
4. Leads are features that are not sufficiently well defined to be drillable, and need further work and/or data.
5. The GCoS reported here represents an indicative estimate of the probability that drilling the Lead would result in a discovery, which would warrant the re-classification of those volumes as a Contingent Resource.
6. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Lead and the potential dependencies between them.

Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, the Client, and/or obtained from other sources (e.g., public domain), and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GCA has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 (see Appendix II).

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMstb). Standard conditions are defined as 14.7 psia and 60°F.

GCA's review involved reviewing pertinent facts, interpretations and assumptions made by NSNRL or others in preparing estimates of resources. GCA performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the resources estimation process, classification and categorization of resources appropriate to the relevant definitions used, and reasonableness of the estimates.

GCA prepared an independent assessment of the resources based on data and interpretations provided by NSNRL.

Definition of Reserves and Resources

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any net present value (NPV) analysis.

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

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the “chance of development” (per PRMS).

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

There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resource volumes are presented as unrisked.

This report has been prepared based on GCA’s understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Qualifications

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA’s remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with NSNRL. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

Notice

This document is confidential and has been prepared for the exclusive use of the Client or parties named herein. It may not be distributed or made available, in whole or in part, to any other company or person without the prior knowledge and written consent of GCA. No person or company other than those for whom it is intended may directly or indirectly rely upon its contents. GCA is acting in an advisory capacity only and, to the fullest extent permitted by law, disclaims all liability for actions or losses derived from any actual or purported reliance on this document (or any other statements or opinions of GCA) by the Client or by any other person or entity.

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It has been a pleasure preparing this Independent Prospective Resources Review of the Devil's Hole Horst, UK Continental Shelf for North Sea Natural Resources Ltd.. Please contact the undersigned if you have any questions.

Yours sincerely,

Gaffney, Cline & Associates

Stephen Lane

Project Manager
Stephen Lane, Technical Director

Stephen C Wright.

Reviewed by
Stephen Wright, Technical Director

Appendices

Appendix I	Glossary
Appendix II	PRMS Reserves Definitions
Appendix III	Monte Carlo Volumetric Estimation Input Parameters and Results

References

Integrated Geochemical Interpretation Ltd. (2019). *GEOCHEMISTRY OF THE DEVIL'S HOLE HORST PROSPECT, MID NORTH SEA HIGH (QUADRANT 27, UKCS).*

Integrated Geochemical Interpretation Ltd. (2019). *MODELLING OF THE PETROLEUM SYSTEMS OF THE DEVIL'S HOLE HORST, MID NORTH SEA HIGH (QUADRANT 27, UKCS).*

Appendix I
Glossary

GLOSSARY

Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
ACQ	Annual contract quantity
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus offset
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow out preventer
bopd	Barrels oil per day
bpd	Barrels per day
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
CBM	Coal bed methane
cf	Standard cubic feet
cfd	Standard cubic feet per day
CIIP	Condensate initially in place
CGR	Condensate to gas ratio
cm	Centimetres
CMM	Coal mine methane
CO_2	Carbon dioxide
cP	Centipoise (a measure of viscosity)
CSG	Coal seam gas
CT	Corporation tax
DCQ	Daily contract quantity
Dev	Developed
DHI	Direct hydrocarbon indicator
DST	Drill stem test
E&A	Exploration & appraisal

E&P	Exploration and production
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement interest
EIA	Environmental impact assessment
ELT	Economic limit test
EMV	Expected monetary value
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FPSO	Floating production, storage and offloading vessel
FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GTL	Gas to liquids
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas

LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact

p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Post stack depth migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved undeveloped
PVT	Pressure volume temperature
P10	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RUB	Russian Rouble
R_w	Resistivity of water
SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water saturation
t	Tonnes
TD	Total depth
te	Tonnes equivalent
THP	Tubing head pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical committee meeting
TOC	Total organic carbon
TOP	Take or pay

tpd	Tonnes per day
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)

Appendix II
PRMS Reserves Definitions

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: 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.

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guideline s
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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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—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—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.

Category	Definition	**Guidelines**
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.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

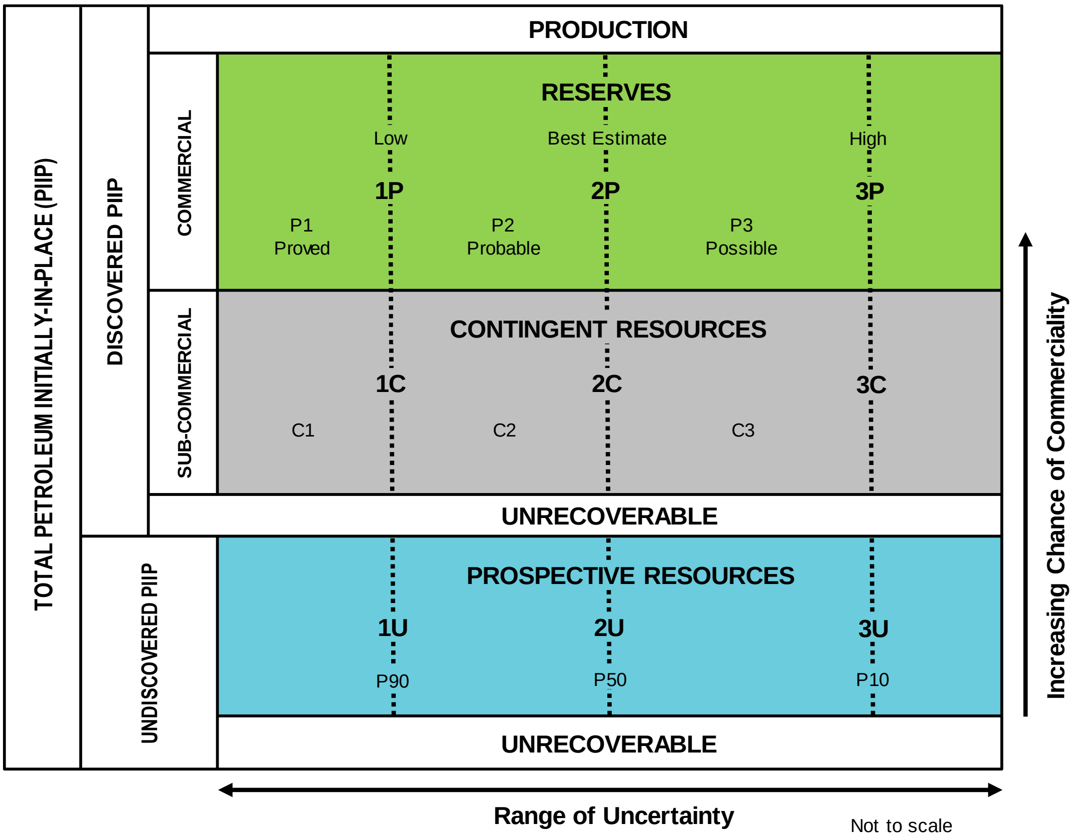
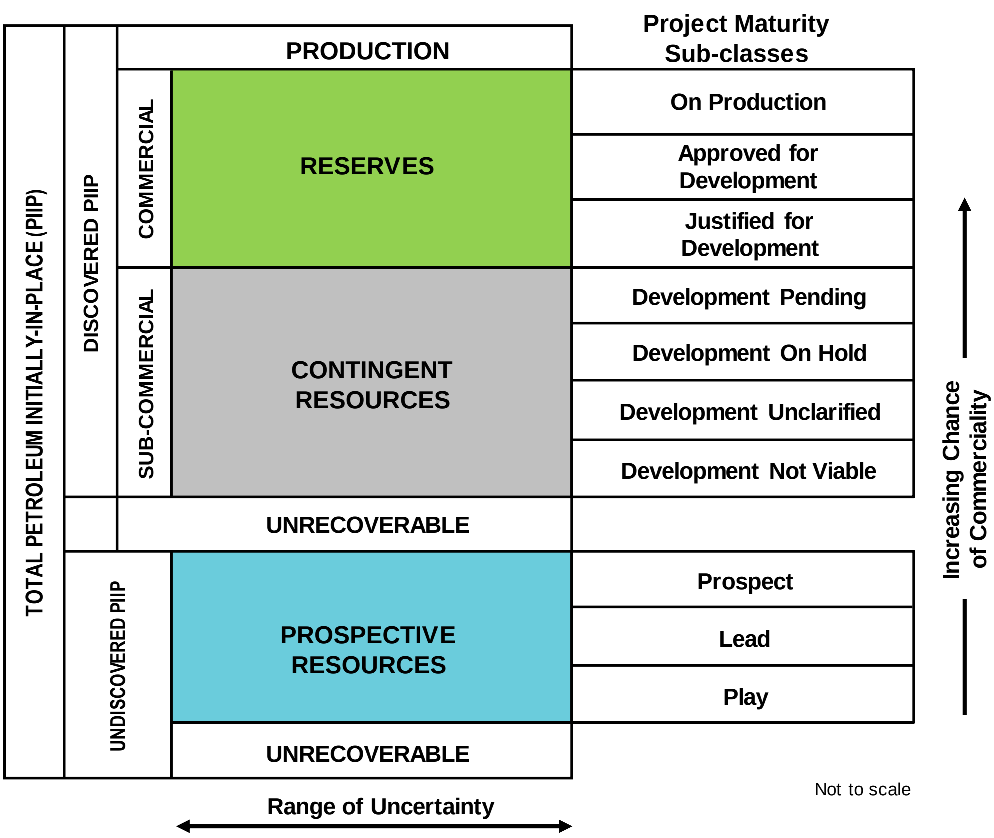


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix III
Monte Carlo Volumetric Estimation Input Parameters and Results

Jurassic Lead
Monte Carlo Volumetric Estimation

Parameter	Units	Low	Mid	High	Distribution
Area					
Gross Thickness					
Gross Rock Volume	MMm3	2,280.3	4,296.9	13,572.1	Lognormal
Net to Gross		0.731	0.860	0.989	Normal
Porosity		0.170	0.220	0.270	Normal
Hydrocarbon Saturation		0.570	0.670	0.771	Normal
Fill Factor		0.864	0.909	0.955	Triangular
Gas Expansion Factor		0.850	0.900	0.950	Triangular
Recovery Factor		0.35	0.40	0.45	Normal
Probabilistic Results		**P90**	**P50**	**P10**	**Mean**
IN-PLACE VOLUME	MMbbl	1,332	2,714	5,485	**3,149**
ESTIMATED ULTIMATE RECOVERY	MMbbl	524	1,081	2,209	**1,259**

Zechstein Z3 Lead
Monte Carlo Volumetric Estimation

Parameter	Units	Low	Mid	High	Distribution
Area					
Gross Thickness					
Gross Rock Volume	MMm3	108.6	484.5	1,117.0	Lognormal
Net to Gross		0.75	0.88	0.99	Normal
Porosity		0.20	0.25	0.30	Normal
Hydrocarbon Saturation		0.570	0.670	0.771	Normal
Formation Volume Factor		0.864	0.909	0.955	Triangular
Fill Factor		0.850	0.900	0.950	Triangular
Recovery Factor		0.05	0.15	0.20	Normal
Probabilistic Results		**P90**	**P50**	**P10**	**Mean**
IN-PLACE VOLUME	MMbbl	75	180	435	**228**
ESTIMATED ULTIMATE RECOVERY	MMbbl	6.0	24.7	73.0	**34**

Zechstein Z1/Z2 Lead
Monte Carlo Volumetric Estimation

Parameter	Units	Low	Mid	High	Distribution
Area					
Gross Thickness					
Gross Rock Volume	MM m3	12,127	27,791	125,216	Lognormal
Net to Gross		0.213	0.250	0.288	Normal
Porosity		0.050	0.100	0.150	Normal
Hydrocarbon Saturation		0.451	0.530	0.610	Normal
Formation Volume Factor		0.864	0.909	0.955	Triangular
Fill Factor		0.85	0.90	0.95	Triangular
Recovery Factor		0.10	0.20	0.25	Normal
Probabilistic Results		**P90**	**P50**	**P10**	**Mean**
IN-PLACE VOLUME	MMbbl	591	1,759	4,662	**2,327**
ESTIMATED ULTIMATE RECOVERY	MMbbl	84.0	290.0	857.5	**408**

Devonian Lead
Monte Carlo Volumetric Estimation

Parameter	Units	Low	Mid	High	Distribution
Area					
Gross Thickness					
Gross Rock Volume	MM m3	746.6	1,651.7	6,979.7	Lognormal
Net to Gross		0.213	0.250	0.288	Normal
Porosity		0.040	0.050	0.060	Normal
Hydrocarbon Saturation		0.340	0.400	0.460	Normal
Formation Volume Factor		0.864	0.909	0.955	Triangular
Fill Factor		0.85	0.90	0.95	Triangular
Recovery Factor		0.20	0.25	0.30	Normal
Probabilistic Results		**P90**	**P50**	**P10**	**Mean**
IN-PLACE VOLUME	MMbbl	18	41	96	**51**
ESTIMATED ULTIMATE RECOVERY	MMbbl	4.3	10.2	24.3	**13**