Prospective Resources Audit, Walton-Morant Licence, Jamaica

Prepared for

United Oil & Gas plc

4 December 2020

Gaffney Cline

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Approved by Gaffney, Cline & Associates Limited

Project Manager: Stephen C Wright — 4 December 2020

Stephen Wright, Technical Director

Reviewed by: N.J. Stott — 4 December 2020

Nick Stronach, Senior Advisor

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Introduction

At the request of United Oil & Gas plc (UOG), Gaffney, Cline & Associates Limited (GaffneyCline) has performed an Independent review of the Prospective Resource estimates associated with the Walton-Morant Block offshore Jamaica.

The Walton-Morant Block is located to the south of the Jamaica (Figure 1). The Block covers an area of 22,400 km^2 and water depth varies from less than 50 m to more than 2,000 m.

UOG holds a 100% working interest in the Block through a Production Sharing Agreement (PSA) following the withdrawal of Tullow Oil. The Block is held under an exploration permit which has been extended for an 18 month period at the beginning of August 2020. During this extension UOG plan to build on the work undertaken by the previous operator to de-risk the identified prospects and leads.

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.

Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client and/or obtained from other sources (e.g., public domain), 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. GaffneyCline 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. GaffneyCline 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, GaffneyCline 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, Version 1.01 (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 resources 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, resources 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). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf). Standard conditions are defined as 14.7 psia and 60°F.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions made by UOG or others in preparing estimates of reserves and resources. GaffneyCline 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 reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

GaffneyCline prepared an independent assessment of the prospective resources based on data and interpretations provided by UOG.

Definition of Prospective Resources

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. 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 analogue developments in the earlier phases of exploration.

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. The Geological Chance of Success (Pg) is reported separately for each Prospect and Lead evaluated. Leads are less defined than prospects, and further evaluation designed to confirm whether or not the lead can be matured into a prospect is required. Such evaluations included the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

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

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with UOG. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or are 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.

Conclusions

1. The Walton-Morant Block is a very large offshore block located to the south of the island of Jamaica. No exploration drilling has occurred on the block to allow local calibration, and the area can be characterised as a frontier block.
2. Exploration activity to date has involved the reprocessing of legacy 2D seismic data, and the acquisition of additional 2D seismic and a 3D seismic survey. These data along with geological studies (including extensive onshore field work in Jamaica) has allowed UOG to develop a geological model for the Walton-Morant Block.
3. The Walton-Morant Block contains two sedimentary basins, the Walton Basin and Morant Basin. The geological evolution of these basins is similar, but there are material differences reflecting the timing of, and different tectonic forces acting on these basins. The Walton Basin is interpreted to be slightly older, commencing in the Mid Cretaceous and to be dominated by carbonate reservoirs. The Morant Basin is slightly younger, and the main reservoirs are interpreted to be sandstones derived from the north (Jamaica).
4. In the Walton Basin within the area covered by 3D seismic UOG has identified five (5) prospects. The principal prospect, Colibri is interpreted as a carbonate prospect located on a ridge in the central part of the basin. Additional prospectivity is provided by seismic amplitude supported stratigraphic traps and basin margin prospects.
5. Basin modelling indicates that if a syn-rift source rock is present in the Walton Basin that it should be capable of generating and expelling a light oil. This is supported by seeps seen in onshore wells and also by the presence of offshore oil slicks and seeps.
6. The Morant Basin is located to the east of the Walton Basin and is constrained by considerably fewer seismic data than the Walton Basin. These data consist of a widely spaced grid of 2D seismic that allows the structure of the basin to be defined. In addition six (6) leads have been mapped on this grid. These leads are all interpreted to be structural leads with sandstone reservoirs. Additional data will have to be acquired before any of these leads can be upgraded to prospects, and they remain high-risk opportunities.
7. The Walton-Morant Block offers the potential to explore two related exploration plays; a variety of traps and reservoirs types in carbonate sediments in the under explored Walton Basin.
8. The Morant Basin is less well calibrated that the adjacent Walton Basin, and the petroleum system is interpreted to be dominated by clastic (sandstone) reservoirs in structural traps. Both basins offer the possibility of finding oil.

Prospective Resource estimates and Geological Chance of Success (Pg) are shown in Table 1.

Table 1: Prospective Resource Estimates for the Walton-Morant Block

Basin	Name	Prospect / Lead	Prospective Resources (MMBbl)				
			U1	U2	U3	Mean	Pg
Walton	Colibri	P	33.4	223	966	406	0.19
	Oriole	P	44.7	172	453	220	0.13
	Streamertail	P	35.6	160	480	221	0.13
	Tody	P	9.4	39.8	113	53.2	0.14
	Euphonia	P	6.5	28.8	81.0	38.3	0.14
Morant	Thunderball	L	76.3	417	1,356	603	0.10
	Moonraker	L	44.9	225	718	323	0.10
	Moneypenny	L	30.8	128	370	173	0.10
	Blofeld	L	29.9	129	361	171	0.08
	Goldeneye	L	41.1	140	346	174	0.10
	Jaws	L	6.7	28.3	82.4	38.5	0.08

Notes:

1. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the prospect(s)/lead(s) in the event that a discovery is made and subsequently developed.
2. The Chance of Geologic Discovery (Pg) reported here represents an indicative estimate of the probability that drilling the prospect(s)/lead(s) would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed (i.e., it does not include a Chance of Development (Pd)).
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
4. Prospective Resources in this table are UOG's working interest fraction of the gross Prospective Resources; they do not represent UOG's actual Net Entitlement under the terms of the PSA that governs the asset, which would be lower.
5. Identification of Prospective Resources associated with a prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
6. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.
7. U1 is the low (P90) estimate, U2 is the best (P50) estimate and U3 is high (P10) estimate.
8. Mean volumes are reported at the request of UOG management.

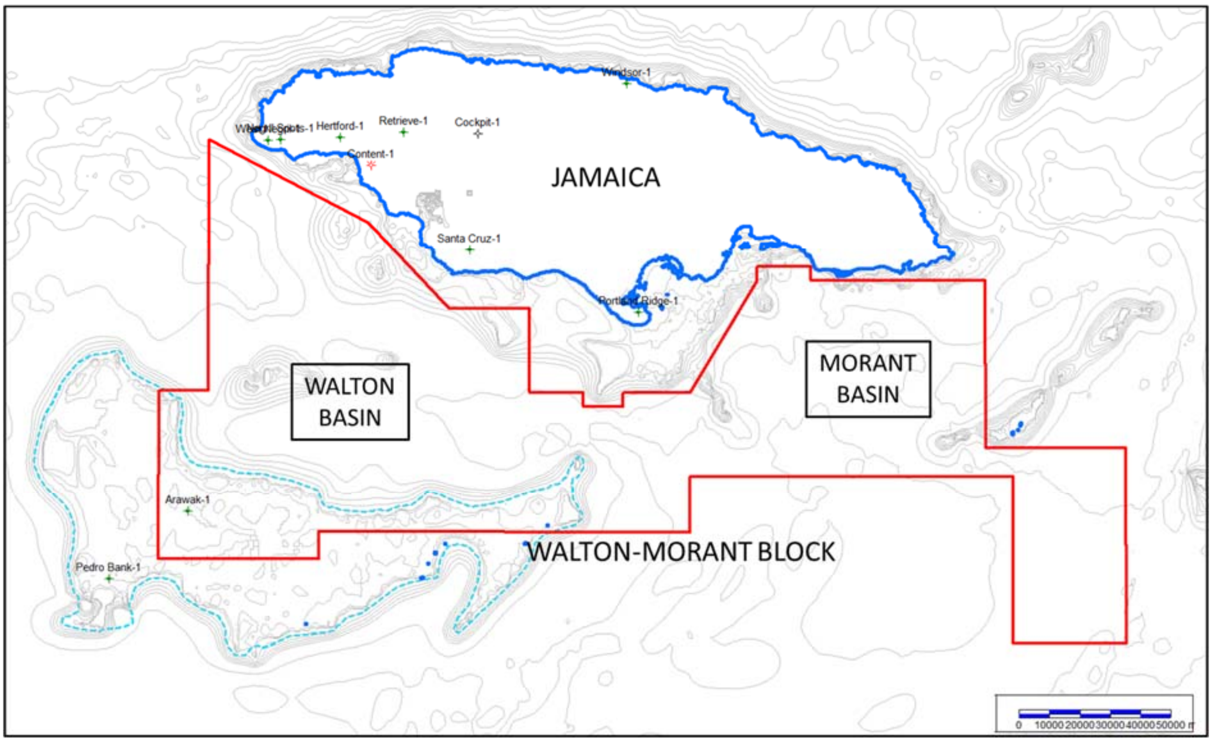
Discussion

1 Regional Setting of the Walton-Morant Licence

1.1 Location of the Basin

The Walton-Morant Licence (Block) is located to the south of the island of Jamaica (Figure 1). It covers an area of 22,400 km^2 and has water depths ranging from <50 to > 2,000 m. Geophysical surveying (gravity, magnetic and seismic) has identified two sedimentary basins within the Block, the Walton Basin and the Morant Basin.

Figure 1: Location of the Walton-Morant Block



Source: GaffneyCline from UOG database

1.2 Geological Evolution

The geological evolution of the island of Jamaica is complex and there are at least two tectonic models to explain its evolution, the Pacific Plate Model, and the other advocates that the island was formed by the separation of the North American and South American tectonic plates. Palaeo-reconstructions in the Pacific Plate Model indicate that during the Late Cretaceous to Mid Miocene that the Jamaica area was juxtaposed to the Yucatan Block of North America. This area was a potential source area for clastic sediments that could be deposited in extensional basins to the south of the current island of Jamaica (e.g. the Walton and Morant Basins).

The Pacific Plate Model is preferred by UOG. The different models are not considered to have a material impact on the prospectivity of the Walton-Morant Block, and are not discussed futher.

Tectonic Evolution:

Following the collapse of the pre-Cretaceous island arc, the basal rocks of Jamaica are overlain by a sequence of sediments that are interpreted to have been deposited in syn-rift extensional basins. These basins are interpreted to have developed as a consequence of the continued movement of the Caribbean tectonic plate to the east. Strike-slip motion is a critical element in the development of the Jamaican areas and sinistral motion is common in the area. The whole of the area is neotectonic and several major earthquakes have occurred in Jamaica in historical times. Review of the offshore seismic data indicates that neotectonic activity is occurring in the Morant Basin area, and that whilst not a major feature is also likely to be occurring in the Walton Basin. This recent tectonic activity will have an effect on the timing of trap generation and potentially trap modification.

Stratigraphy:

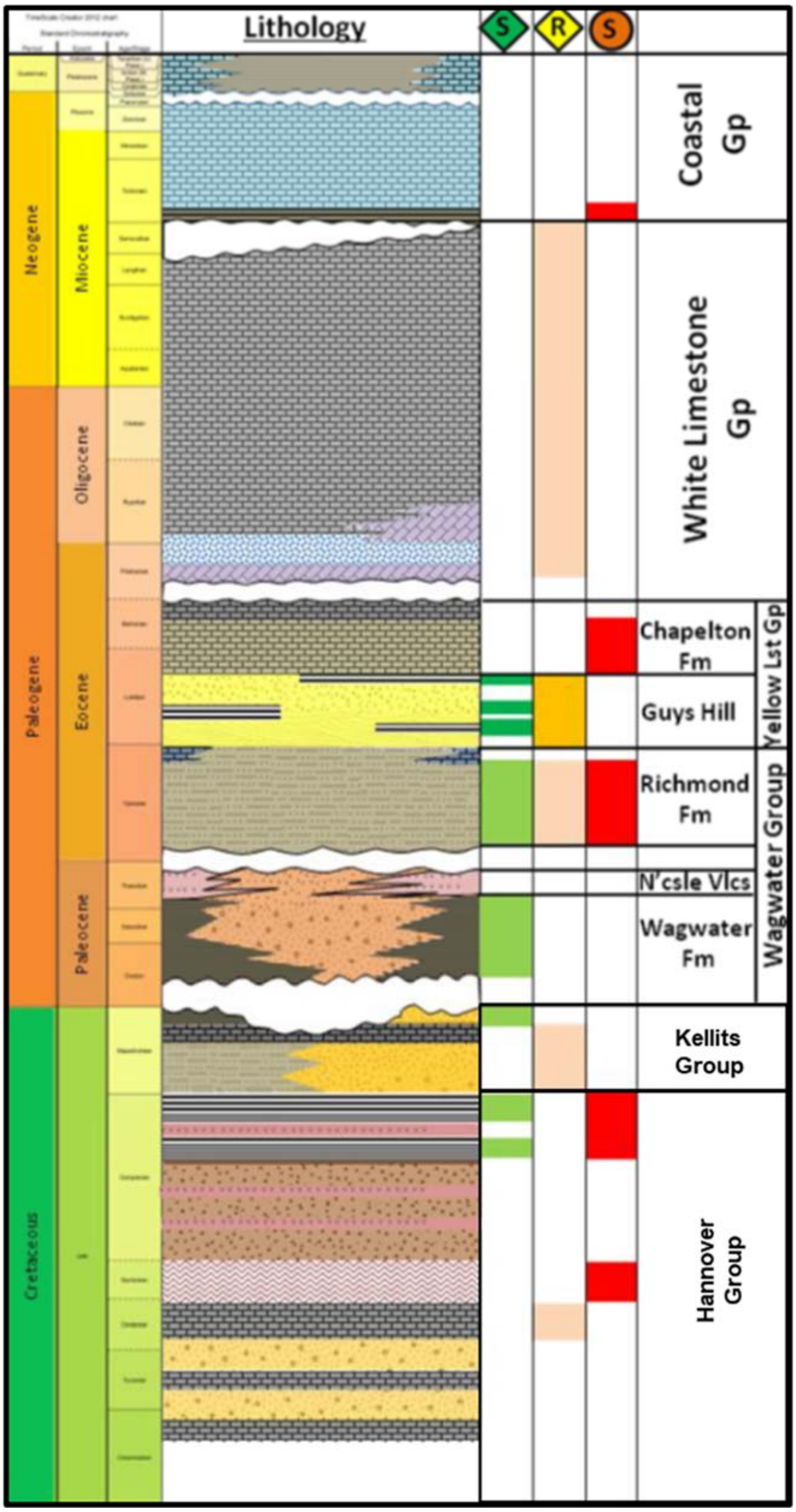
No sediments crop out within the area of the Walton-Morant Block, and all stratigraphic assessment is based on correlation with outcrops on the island of Jamaica or the wells on Pedro Bank (Figure 2). The oldest rocks are poorly dated but believed to be of Early Cretaceous age and constitute an island arc complex. These rocks are overlain by Upper Cretaceous clastic (sandstones and shales) of the Hannover Group. It is interpreted that offshore these sediments pass upwards and laterally into carbonate sediments. This package of sediments is considered the syn-rift sequence and is interpreted to contain the potential source rocks of the Walton and Morant Basins.

The onshore stratigraphy and by analogy the stratigraphy of the Walton Basin is shown in Figure 2. This shows that the earliest sediments are dominated by a clastic sequence consisting of interbedded sandstone and shale with volcanoclastic sediments. This sequence is unconformably overlain by a mixed clastic and carbonate sequence of Late Cretaceous age, referred to the Kellits Group.

The Kellits Group is unconformably overlain by the Wagwater Group, a clastic-dominated syn-rift sequence, and the Yellow Limestone Group. The latter comprises a heterogeneous mixture of clastic (sandstones and shales) and carbonate sediments. These sediments are overlain by the carbonates of the White Limestone Group and Coastal Group.

The offshore sequence is less well calibrated. The Pedro Bank-1 and Arawak-1 wells provide correlation in the shallower part of the stratigraphic column, however, the deeper syn-rift sequence identified on the seismic data has not been penetrated. This sequence is interpreted to contain both potential source rocks and reservoir intervals in the Walton and Morant Basins.

Figure 2: Generalised Stratigraphic Column



Source: modified after Tullow

2 Database

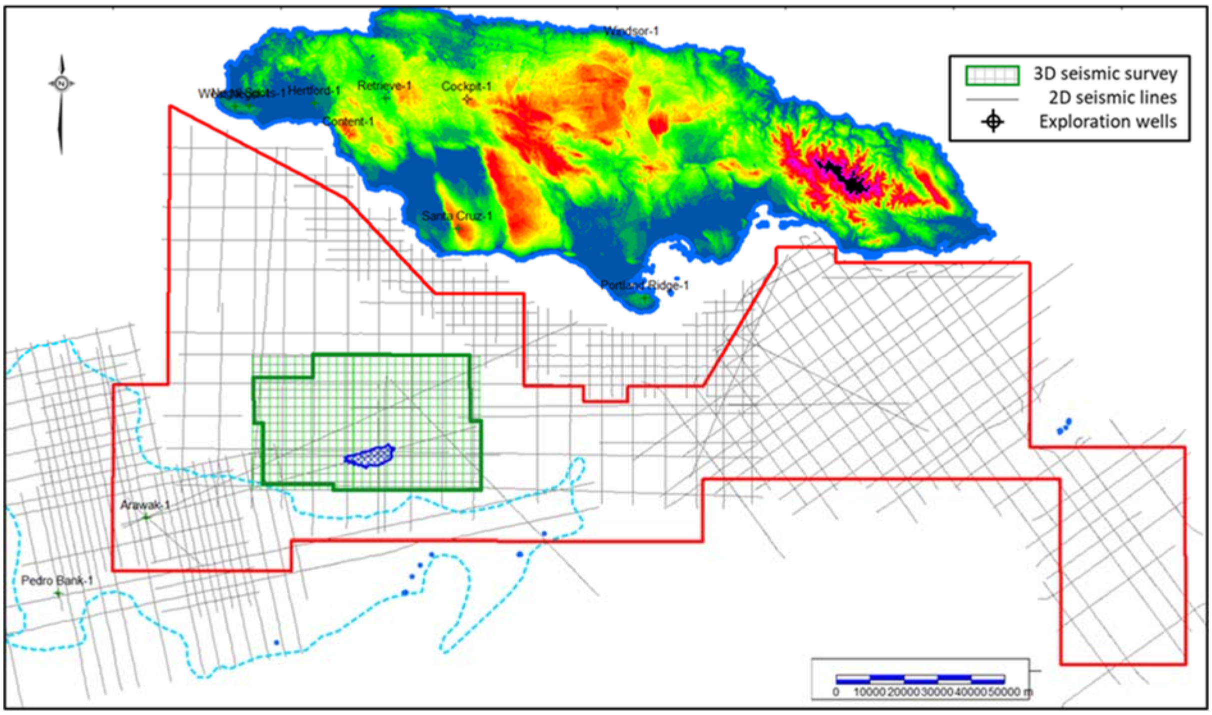
2.1 Seismic Data

Seismic data in the Walton-Morant Block consists of both 2D and 3D seismic data. In their evaluation. UOG has considered 3,650 line km of 2D seismic data (WAMT16 and WAMT17 surveys) acquired by Tullow in 2016 and 2017 respectively. These surveys provide a grid of data across the block and importantly provide tie-lines to the Pedro Bank-1 and Arawak-1 exploration wells.

Additional legacy 2D seismic data occurs within the area of the block but these data are not available to UOG.

The 3D seismic data was acquired in the Walton Basin in 2018. A 2,250 km^2 3D seismic survey (WAMT18) was shot over the area of the block containing the Colibri Prospect and several other prospects. These seismic data have undergone extensive processing including Pre-STM and anisotropic PreSDM processing. The location of these data are shown in Figure 3.

Figure 3: Seismic and Well Database



Source: GaffneyCline from UOG database

2.2 Well Data

11 oil and gas exploration wells have been drilled in Jamaica between 1955 and 1982. Of these wells only 2, Pedro Bank-1 (1970) and Arawak-1 (1982) were drilled offshore. Both of these wells are located on the Pedro Bank to the southwest of the Walton-Morant Basin (Figure 3).

2.3 Other Data

In addition to well and seismic data a large amount of supporting data and information has been evaluated by UOG in the preparation of the Prospective Resource estimates. These data include:

- Marine gravity and magnetic surveys that were acquired with the WAMT16 and WANT17 seismic surveys.
- Bathymetric, drop core and heatflow data
- Field studies onshore Jamaica – onshore analogues for the Walton-Morant Basins.
- Slick and seep data – to confirm the presence of a mature and generating source rock in the area of the Walton-Morant Block.
- Source rock and oil stain geochemical analysis from field outcrop, core and cuttings samples.
- Basin modelling study to constrain the petroleum system of the Walton-Morant Block.

3 Prospectivity Evaluation

There are currently no potentially commercial oil or gas discoveries on Jamaica or in the offshore waters of Jamaica. Eleven exploration wells have been drilled in Jamaican territory (only 2 offshore) and none has resulted in a potentially commercial discovery. However, these wells and onshore mapping and fieldwork have demonstrated the presence of the key elements for a working petroleum system.

The stratigraphy encountered onshore Jamaica and in the offshore boreholes provides evidence for the presence of potential clastic and carbonate reservoirs, seals and source rocks. Seismic data has been interpreted to show the presence of potential traps. Therefore the possibility of all of the key elements are demonstrated. However, to date no potentially commercial accumulation has been discovered. Therefore whilst the essential elements have been identified no success has been achieved. The new (seismic) data and the interpretation of these data using regional knowledge and analogues means that the Walton-Morant Basin is in effect a frontier basin in which the essential elements of the petroleum system have been indicated but not demonstrated.

3.1 Prospectivity of the Walton Basin

The Walton Basin sedimentary fill consists of syn-rift sediments overlying basement rocks. These syn-rift sediments are interpreted to consist of sandstones, shales and possibly volcanic derived sediments that pass upwards into carbonate dominated lithologies. These carbonates include rudist limestones and in places resedimented platform carbonates into deeper water sediments are age equivalent to similar lithologies seen onshore. These carbonate sediments are interpreted to be the principal reservoir for the Walton Basin. In the Colibri Prospect they are represented by in-situ carbonates that may include rudist bioherms and to have potentially undergone karstic processes prior to the deposition of the overlying sediments. In the Oriole and Streamertail prospects these sediments are interpreted to be reworked carbonate shed from the platform margin on the north of the basin into deepwater sediments.

It is interpreted that the shales in the syn-rift sequence could include potential source rocks and that these may be the origin of the seeps and shows identified in the region. The main play elements are discussed below:

<u>Reservoirs</u>

In the Walton Basin there is the potential for both siliciclastic and carbonate reservoirs. However, the prospects currently identified are interpreted to have carbonate reservoirs. These carbonate reservoir range from in-situ shallow water shoals and platforms (including rudist biostromes) to resedimented shallow water carbonates deposited in deeper water. There is little or no calibration of reservoir quality and reservoir parameters are taken from appropriate onshore and global analogues.

<u>Source rocks</u>

The interpretation of source rocks in the offshore of Jamaica relies on the presence of Cretaceous age organic rich shales onshore of Cenomania-Turonian age with TOC of up to 8% in what are interpreted to be correlatives of the offshore (Figure 2) and the presence of oil shows in 10 of the 11 of the exploration wells. This is further supported by the presence of maritime slicks that are interpreted to be derived from seeps within the offshore basins (e.g. Blowers Reef seep in the Walton Basin). The analysis of oil seep samples onshore and offshore indicates that thermogenic hydrocarbons have been generated and that expulsion has occurred. However, it does not provide any data on the thickness, richness or maturity of any of the candidate source rocks.

Seals

Sealing intervals are interpreted to occur within the syn-rift and the post-rift section that would provide top seals to potential accumulations within the Walton Basin.

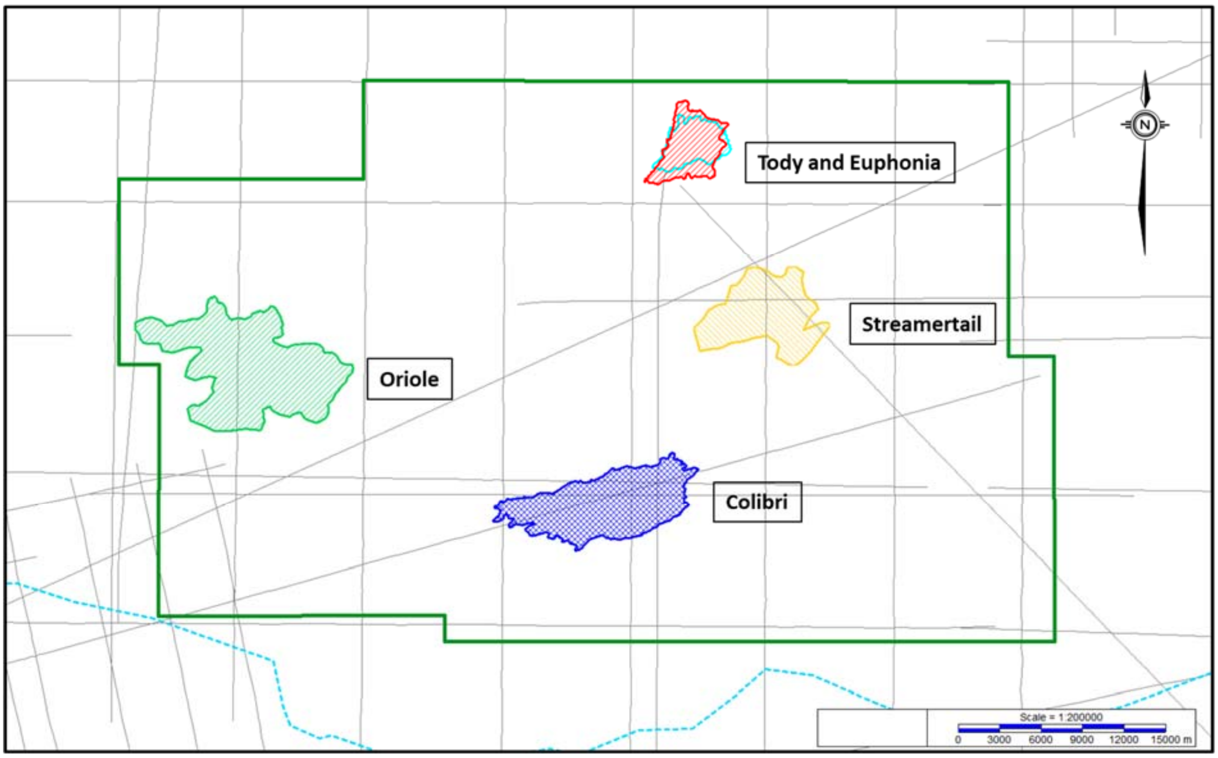
Hydrocarbon Generation and Migration

There is little information to constrain hydrocarbon generation and migration in the Walton Basin. Basin modelling studies have been performed by Tullow (then Operator) considering both syn-rift and post-rift source rocks. Sensitivities for these models have included kerogen composition, and heat flow. The results of these models indicate that depending on the source rock interval selected and the heat flow that oil and gas been generated in all or some of the source rocks. Migration studies (based on mapping of the 3D seismic data) indicate that all of the prospects as mapped are on potential migration routes. Migration losses have also been considered which reduces the volumes migrating to the traps. All of these results are very dependent on the inputs and assumptions used in the modelling. They however, show that hydrocarbon generation and migration is likely in the Walton Basin, as supported by hydrocarbon seeps. However, the models are essentially un-calibrated and hydrocarbon generation and migration remains a significant risk.

Prospects and Leads

Five (5) prospects have been identified by UOG based on work initially undertaken by Tullow when they were the Operator of the Block (Figure 4). All of the prospects lie within the area of the Walton Basin covered by the 3D seismic data and range from structural traps (Colibri Prospect) through combination structural / stratigraphic traps (Tody / Euphonia) to solely stratigraphic traps (Oriole and Streamertail). In addition to these prospects a number of leads have been identified outside of the 3D seismic area, these have not been assessed in the preparation of this report.

Figure 4: Walton Basin, Prospects within 3D Seismic Survey



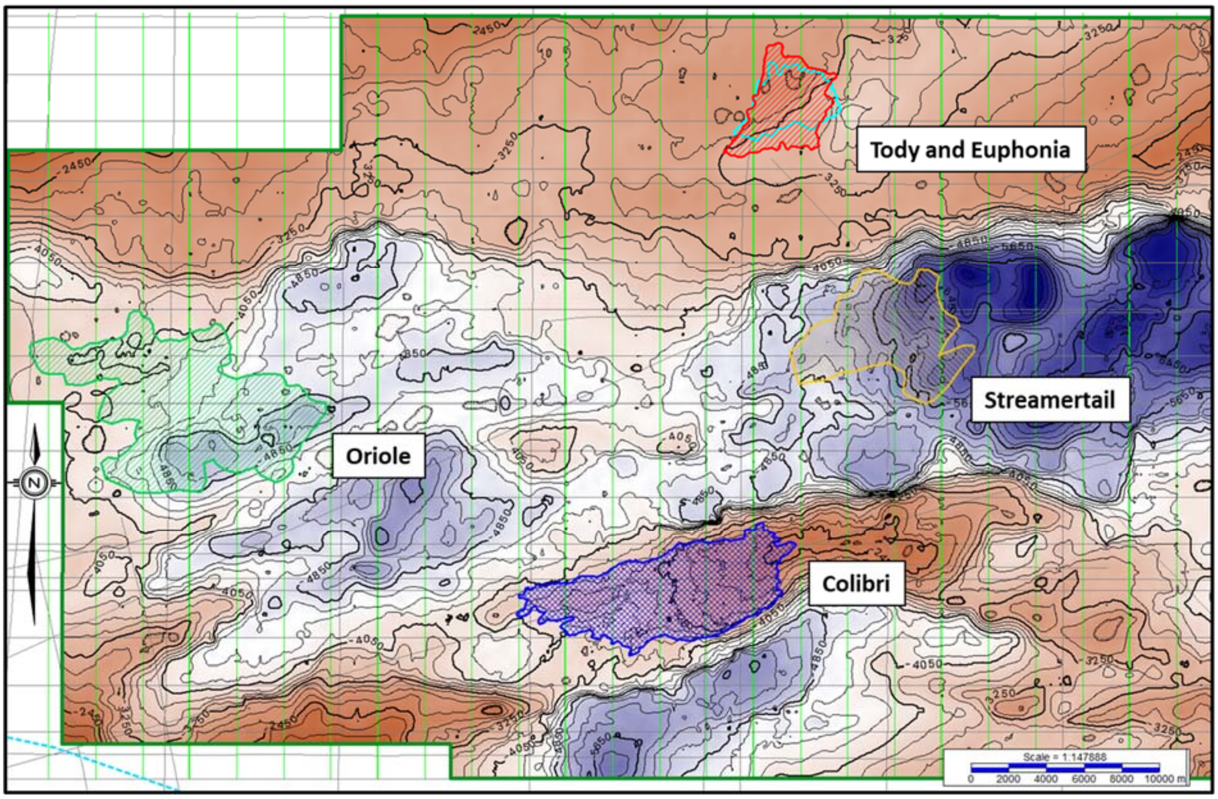
Source: GaffneyCline from UOG database

Colibri Prospect

The Colibri Prospect lies on an east-west oriented high in the centre of the Walton Basin (Figure 5). This high forms a ridge within the syn-rift section. The reservoir for the Colibri Prospect is interpreted to be a carbonate platform eroded remnant that developed on the synrift high. Analogues, and indications from the internal seismic structure suggest that this interval could be composed on platform carbonates with rudist build-ups or biostromes.

The Prospect consists of a fault bounded east-west ridge that dips gently to the west (Figure 6). Top seal is provided by sediments in the overlying post-rift sequence and there is an angular unconformity beneath these younger sediments. Beneath the unconformity the proposed reservoir interval is truncated with progressively more of the sequence being removed towards the crest of the closure (Figure 7). This unconformity surface may indicate subaerial exposure before the deposition of the overlying sediments. The exposure of the carbonate sediments in the proposed reservoir section would have allowed diagenetic processes including the development of karst to have occurred. These processes potentially have significant impact on improving reservoir quality at the Colibri Prospect.

Figure 5: Walton Basin Prospects Base Rift Depth Structure



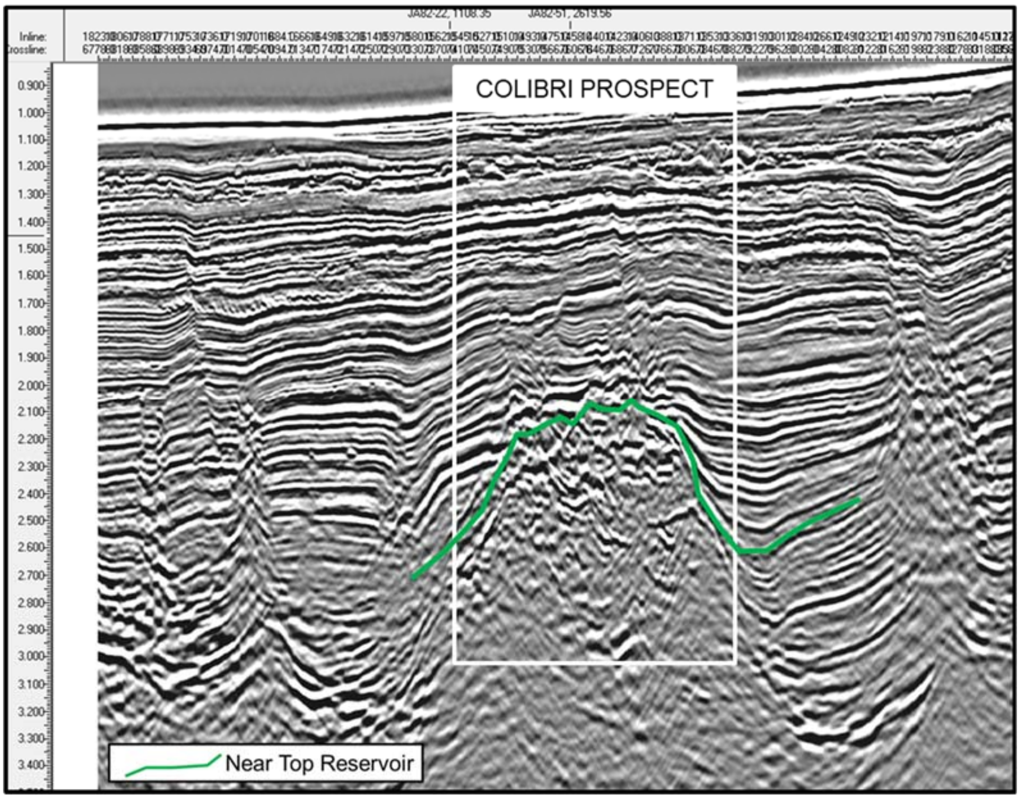
Source: GaffneyCline from UOG database

Lateral seal to the Colibri Prospect is provided by sediments within the post-rift sequence (Figure 6). These are interpreted to be marine (possibly deep marine) sediments. However, there is no local calibration by well data. The geometry of these sediments on the southern side of the Colibri Prospect provide a potential thief zone, this has been factored into the volumetric estimates for the prospect.

Charge to the prospect has been modelled, the geometry of the potential feeder beds means that a limited part of the Walton Basin is available. The absence of any seismic attribute that could indicate the presence of hydrocarbons in the Colibri Prospect is not unexpected and is not considered to be detrimental to the prospect. Basin modelling has also been used to constrain the composition of the hydrocarbons potentially trapped in the prospect.

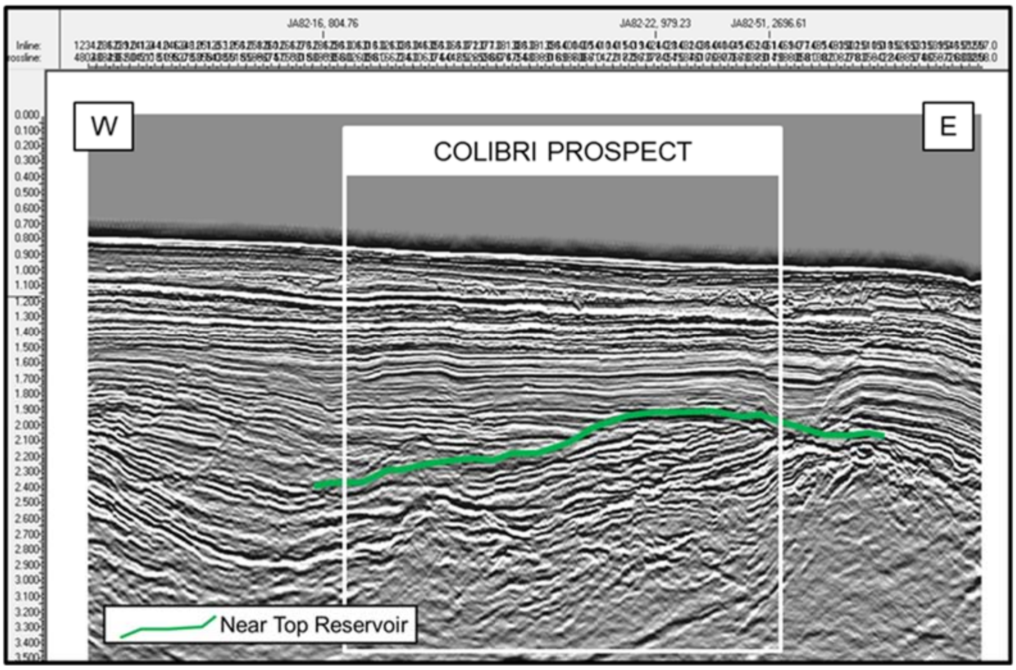
The mapping of the Colibri Prospect using the 3D data has been reviewed and Prospective Resource estimates and a Geological Chance of Success (Pg) estimate have been generated. The principal risk associated with the Colibri Prospect is trap and seal. The geometry of the prospect is reasonably well imaged on the 3D seismic data, but the trap requires the truncation of the carbonate reservoir below the overlying seal, and there is no independent closure at the reservoir level. Satellite slicks have been mapped in the area (Figure 8). These slicks are interpreted to be caused by oil seeps and repeat data increases their reliability. However, the presence of these possible seeps to the east Colibri Prospect indicates that the seal of the prospect may be leaking in this area. The results are summarised in Table 1, and the input parameters provided in Appendix I.

Figure 6: Seismic Inline across Colibri Prospect



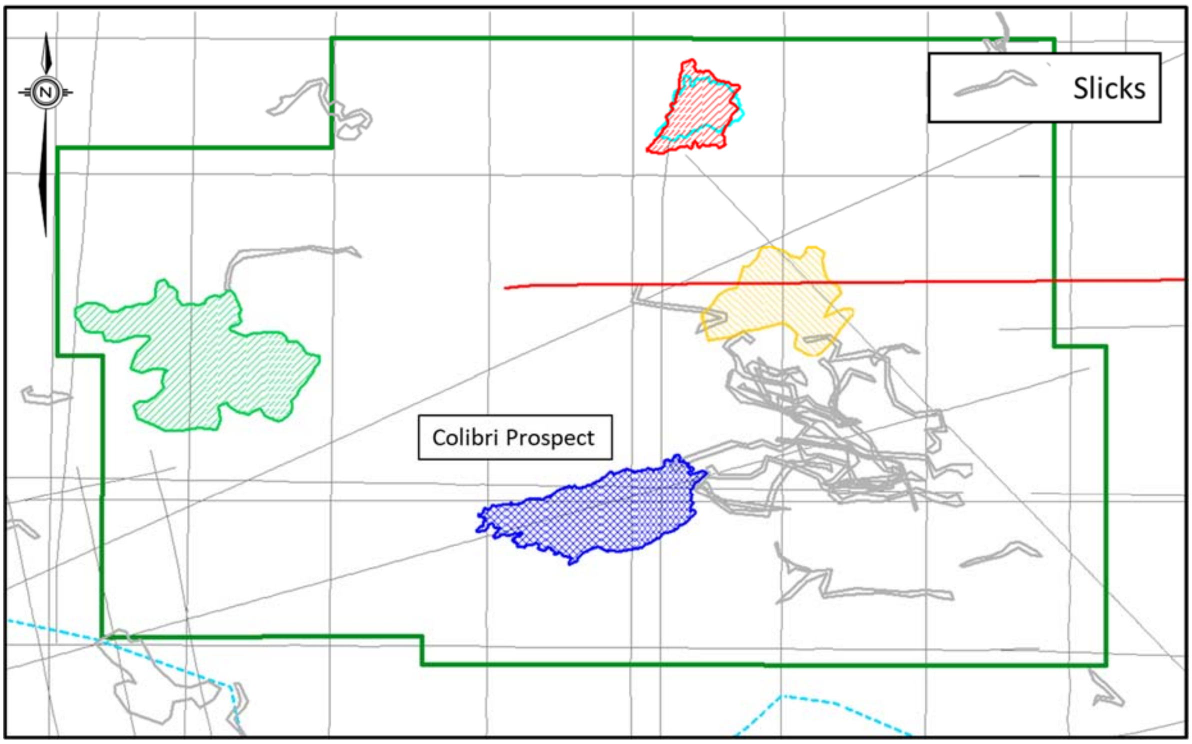
Source: GaffneyCline from UOG database

Figure 7: Colibri Prospect – East-West Seismic Line



Source: GaffneyCline from UOG database

Figure 8: Colibri Prospect and Surface Slick Traces



Source: GaffneyCline from UOG database

Oriole Prospect

The Oriole Prospect is located to the north of the Colibri Prospect (Figures 4 and 5) and is a stratigraphic trap interpreted to have developed by the deposition of shallow water carbonate sediments (grainstones and possibly larger clasts) into a deep water setting forming a fan shaped geometry that is defined on the 3D seismic data (Figure 9). There is no structural element to the trap and the area of closure is defined by different seismic amplitudes associated with the single seismic “loop” that defines the prospect. Different amplitude cut-offs have been used by UOG to define the size of the trap, these variations may reflect variations in lithology (channel dominated versus fan dominated deposition). There is no evidence for a down-dip cut-off of any amplitude in the anomaly as mapped indicating that the trap is either full, or that no fluid response is seen in the 3D seismic data.

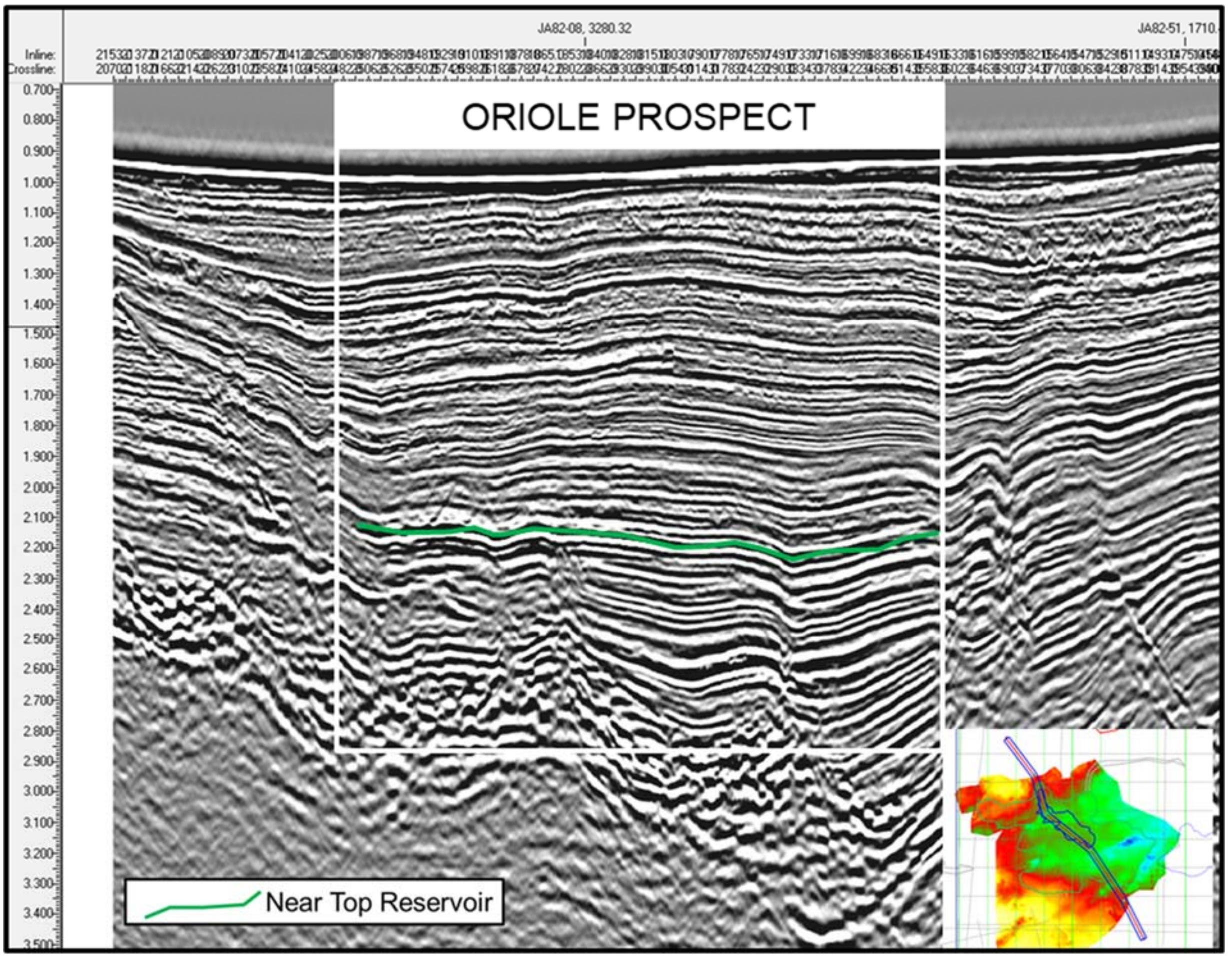
The trap is mapped as a single “loop” seismic and seal is expected to be provided by overlying and underlying fine grained deepwater sediments.

Basin modelling indicates that the prospect is well located to receive any hydrocarbons migrating from deeper source rocks located in the Walton Basin. Basin modelling has also been used to constrain the composition of the hydrocarbons potentially trapped in the prospect.

The principal risk for the prospect is that the seismic attribute as mapped is a lithological marker and that there is no effective reservoir within the area of the prospect. No down-dip amplitude cut-off has been observed that could have indicated the presence of hydrocarbons.

The mapping of the Oriole Prospect using the 3D data has been reviewed and Prospective Resource estimates and a Geological Chance of Success (Pg) estimate have been generated. The results are summarised in Table 1, and the input parameters provided in Appendix I.

Figure 9: Oriole Prospect – Random Seismic Section



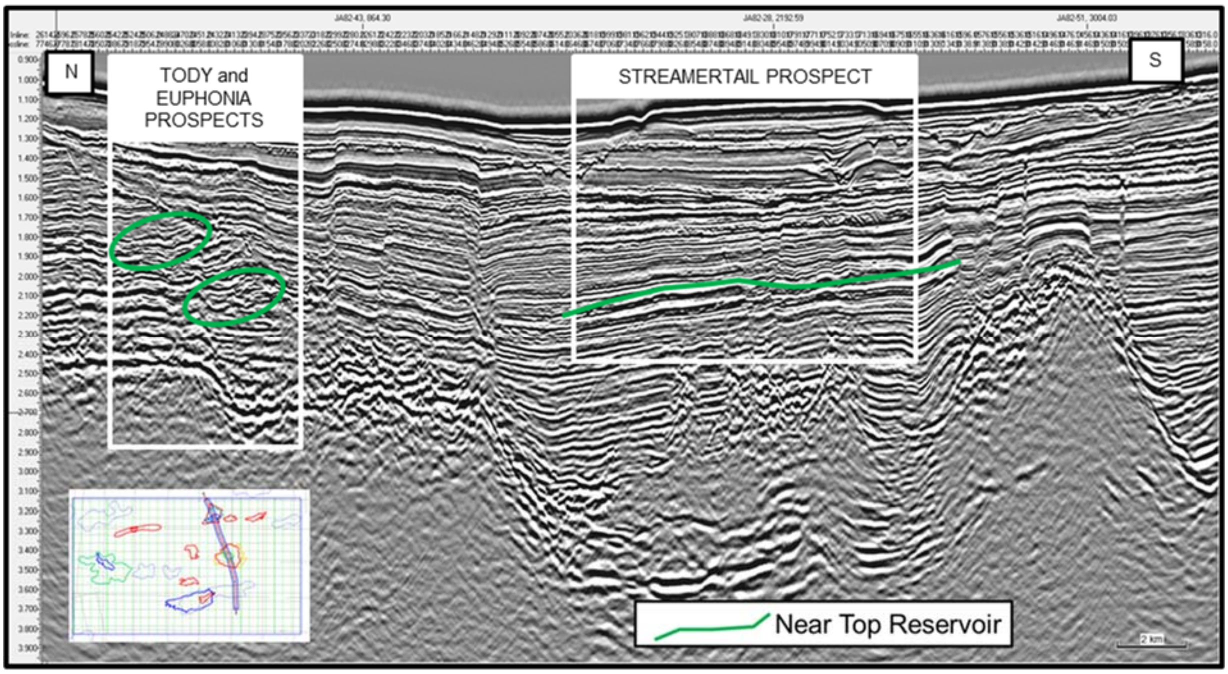
Source: GaffneyCline from UOG database

Streamertail Prospect

Streamertail Prospect is an assemblage of clustered seismic amplitude anomalies located at a similar stratigraphic level to the amplitude at the Oriole Prospect (Figure 10). All of the essential aspects of the prospect are similar to those at the Oriole Prospect. Streamertail is interpreted to have updip pinch-out onto the Colibri and Walton Bank highs and downdip thinning. Charge is modelled to be similar to the Oriole Prospect charge. No down-dip amplitude cut-off has been observed.

The seismic mapping of the Streamertail Prospect using the 3D data has been reviewed, and the presence of the seismic amplitude confirmed. Prospective Resource estimates and a Geological Chance of Success (Pg) estimate for the prospect have been generated. The results are summarised in Table 1, and the input parameters provided in Appendix I.

Figure 10: Streamertail, Euphonia and Tody Prospects: Random Seismic Line



Source: GaffneyCline from UOG database

Tody / Euphonia Prospects

The Tody and Euphonia Prospects are linked prospects. They are interpreted as stacked carbonate shoals (Eocene-Oligocene age) located in an overall four-way dip closure on the northern margin of the Walton Basin (Figure 5). The shoals (reservoirs) are interpreted to be interbedded with tight limestones and pelagic marls. The target horizons overlie each other and it may be possible to test both reservoir intervals with a single exploration well. The most-likely charge kitchen is from the Walton Basin depocentre to the south of the prospects, although a kitchen within the Walton Bank is possible.

The mapping of the Tody / Euphonia Prospects using the 3D data has been reviewed. The trap geometry requires both dip and stratigraphic elements. This increases the risks associated with these prospects. Prospective Resource estimates and a Geological Chance of Success (Pg) estimate have been generated. The results are summarised in Table 1, and the input parameters provided in Appendix I.

3.2 Prospectivity of the Morant Basin

The Morant Basin lies to the east of the Walton Basin (Figure 1), and the interpretation of the hydrocarbon prospectivity is less well constrained than in the Walton Basin as the interpretation relies on a broadly (~5 km line interval) spaced 2D seismic dataset (Figure 3).

The Morant Basin has a different stratigraphic and tectonic history than the adjacent Walton Basin. The onset of synrift deposition is interpreted to be later than in the Walton Basin. The main difference appears to be that the area is still undergoing structural deformation. This active tectonism also allows clastic sediments (sandstones and shales) to be deposited in the basin when only carbonates are interpreted to have been accumulating in the Walton Basin.

This reflects the regional tectonics and the proximity to the restraining bend that also leads to active deformation in the Blue Mountains of Jamaica.

The stratigraphy of the Morant Basin is essentially uncalibrated as no exploration wells have been drilled in the basin and all correlation requires long distance "jump" correlation to the nearest wells onshore Jamaica or on Pedro Bank. A Cretaceous pre-rift sequence (basement) is interpreted to be overlain a Latest Cretaceous to Paleogene extensional syn-rift sequence. This is unconformably overlain by Miocene to Recent sediments deposited in a transtensional basin.

Reservoirs

In comparison to the adjacent Walton Basin the reservoirs of the Morant Basin are interpreted to be predominantly clastic (sandstone) reservoirs of Eocene age (Figure 11). The sediments are expected to be the deepwater equivalents of the fluvial to shallow marine sandstones seen in outcrop onshore Jamaica.

Source Rocks

Source rocks of Cretaceous to Eocene age are interpreted to be present by analogy with the adjacent Morant Basin and onshore sedimentary sections. As no wells have been drilled presence, thickness and quality of any potential source rock is uncertain. Modelling of potential source rock intervals indicates that source rocks are thermally mature for the generation and expulsion of oil. The results of this basin modelling have been used to constrain the inputs (FVF, GOR etc.) into the volumetric estimates.

Seals

Seals are anticipated to be developed interbedded with the reservoir intervals and also in the overlying post-rift sections.

Seismic Database

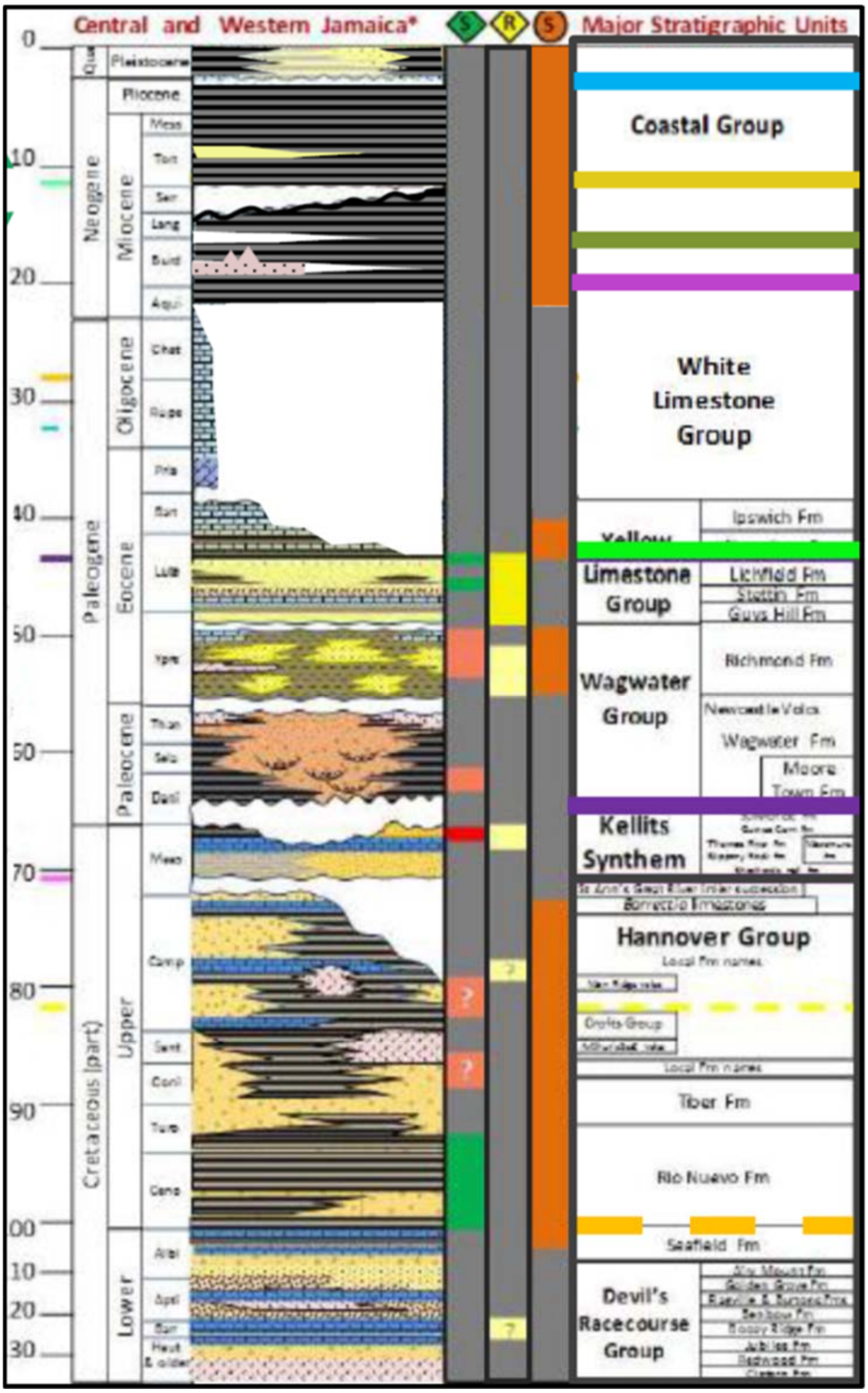
Seismic data in the Morant Basin comprises relatively widely spaced reconnaissance 2D seismic lines (Figure 3). Average line spacing is 3 to 8 km allowing a regional understanding of the basin to be developed, but making mapping of structures challenging.

Prospects and Leads

No prospects have been identified, UOG has identified six leads in the Morant Basin (Figure 12). These are all structural leads and are clustered in the northern basin. All of the structures currently identified are considered leads as additional seismic data will be required before a drill decision could be made. This may require additional infill by 2D seismic data, or more likely a 3D seismic survey similar to that shot in the adjacent Wilton Basin.

All of the leads have similar play elements, they have the reservoir developed in the same stratigraphic level, rely on a common petroleum source rock system (although with slightly different migration routes) and traps have developed in a similar fashion.

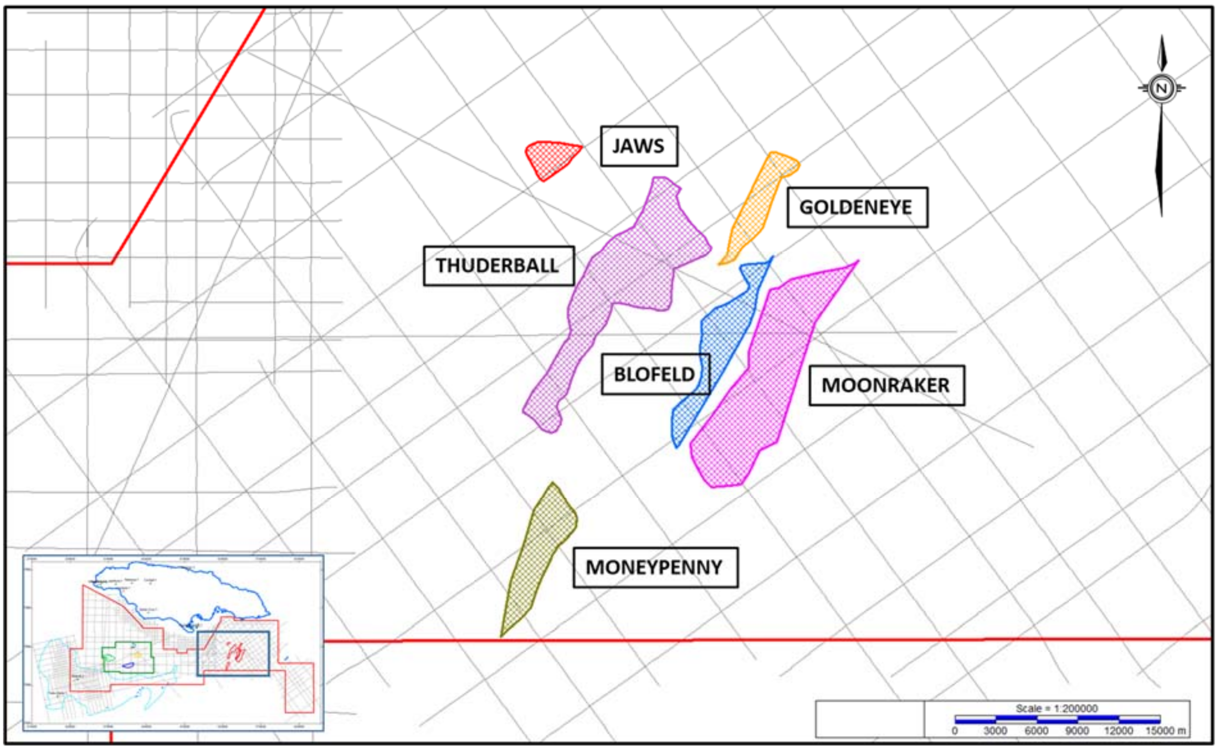
Figure 11: Morant Basin: Stratigraphic Column



Source: modified by GaffneyCline from UOG database

The following leads have been identified:

Figure 12: Morant Basin, Leads



Source: GaffneyCline from UOG database

Thunderball Lead

The Thunderball lead is a large rotated fault block with three-way dip closure lying in the centre of the Morant Basin (Figure 13). Mapping of the structure is constrained by 7 2D seismic lines. Thunderball is a large rotated fault block with the sandstone reservoir anticipated in the Early Cenozoic syn-rift package. Miocene sediments are interpreted to onlap the high with the Mid Miocene Unconformity (1) possible truncating the crest of the structure.

Moonraker Lead

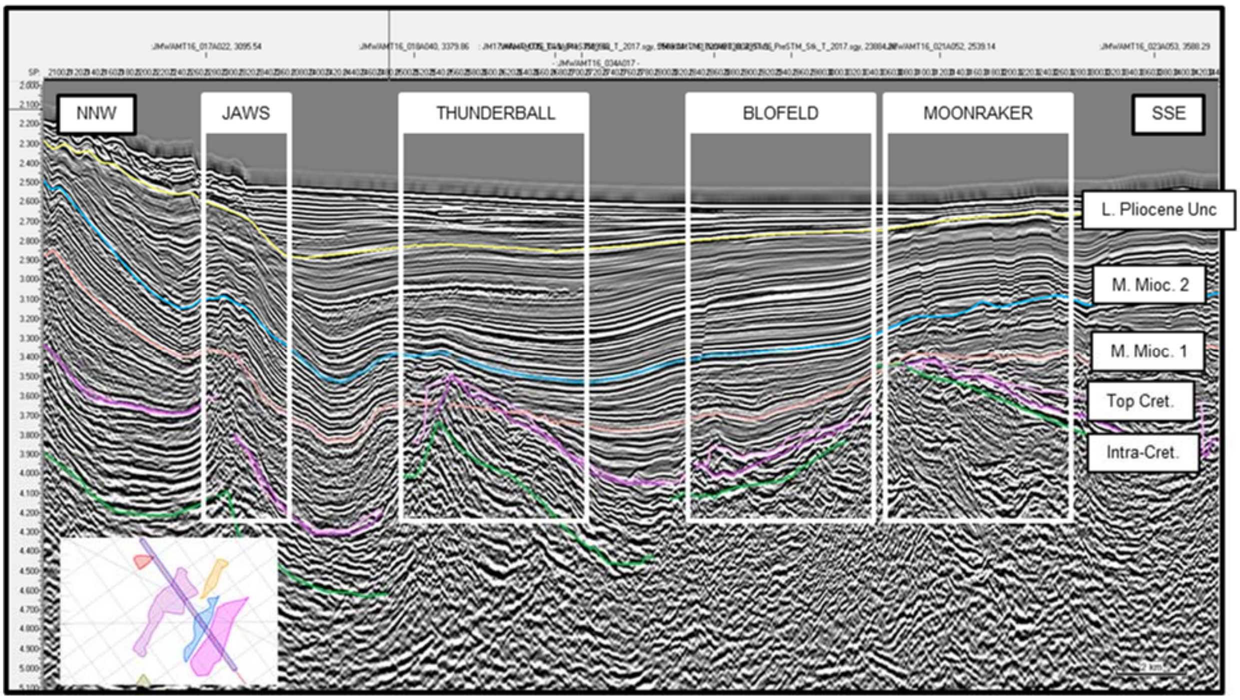
The Moonraker lead lies to the east of the Thunderball lead (Figure 13) and is a rotated fault block downthrown to a high to the east, closure in the best and upside require fault seal between the Moonraker structure and the adjacent upthrown block. The Moonraker lead is constrained by up to 7 2D seismic lines. As with the Thunderball lead, the reservoir is interpreted to be developed in the Early Cenozoic syn-rift package and top seal is provided by the overlying Miocene sequence which has in places been interpreted to contain volcanoclastic rocks which may have a negative impact on seal integrity.

Moneypenny Lead:

The Moneypenny lead is a smaller three-way dip and fault closed rotated fault block (Figure 14). The mapping is constrained by 3 2D seismic lines (Figure 13), as with the Moonraker lead, the reservoir is interpreted to be developed in the Early Cenozoic interval.

Top seal is provided by the overlying Miocene sequence which is interpreted to contain volcanoclastic rocks that might compromise the top seal.

Figure 13: Jaws, Thunderball, Blofeld and Moonraker Leads



Source: GaffneyCline from UOG database

<u>Blofeld Lead</u>

Is a downthrown structure mapped to the west of the Moonraker lead, constrained by some 5 2D seismic lines (Figure 13). Fault seal between Blofeld and Moonraker is required for the Blofeld trap to be effective. The fault is mapped to bring the Early Cenozoic reservoir interval into fault juxtaposition with older rocks that are believed to be impermeable deepwater shales and limestones.

<u>Goldeneye Lead</u>

The Goldeneye lead is located in the centre of the Morant Basin and the structure is mapped on 3 2D seismic lines. The lead is mapped as a rotated fault block, (Figure 14) but due to the limited number of seismic lines there is a risk of significant fault aliasing and the structural configuration is poorly constrained. As with all of the other leads the Goldeneye lead is anticipated to have reservoir within the Early Cenozoic package.

<u>Jaws Lead</u>

The Jaws lead is mapped as a rotated fault block with three-way dip closure (Figure 13). The lead is only mapped on two (2) 2D seismic lines which show significant different structural styles. The Jaws lead is the only lead in the Morant Basin that has a significant seabed expression (Figure 15), this and the onlapping nature of the shallower sediments on the high indicate that this may be neotectonic and the structure has undergone recent deformation.

The available seismic data does not indicate any faults passing from the reservoir level to the surface, however structural integrity is an identified risk.

Figure 14: Goldeneye Lead

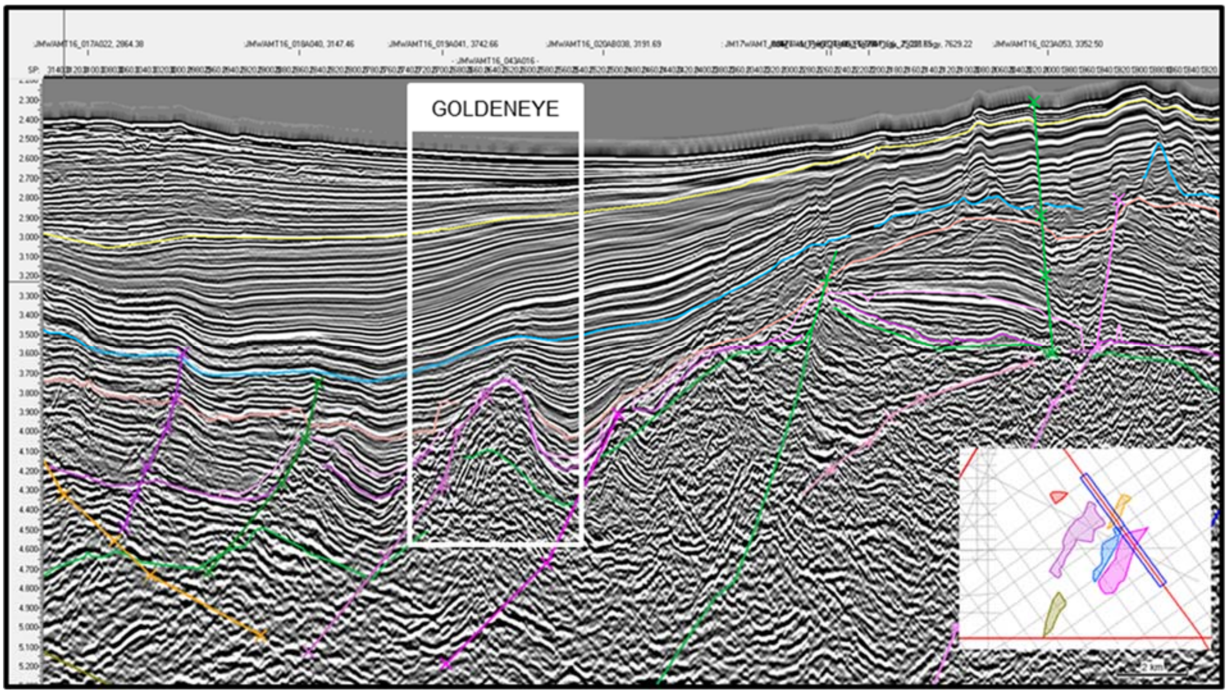
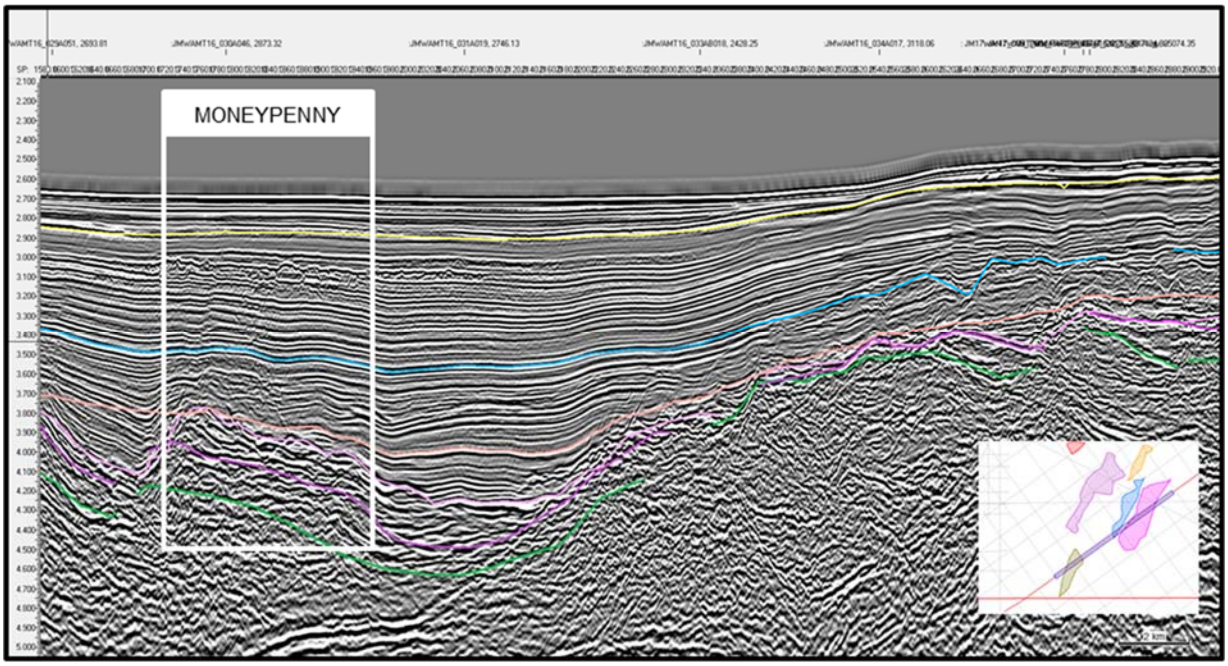
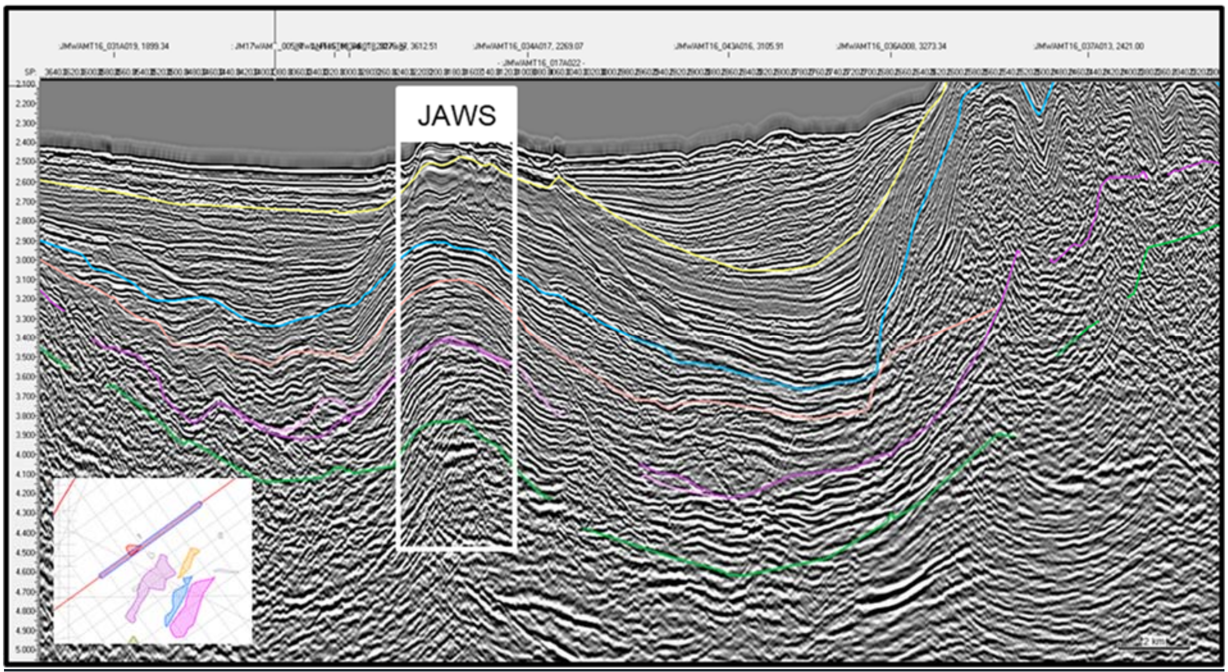


Figure 15: Moneypenny Lead



Source: GaffneyCline from UOG database

Figure 16: Jaws Lead



Source: GaffneyCline from UOG database

<u>Morant Basin Summary</u>

The Morant Basin is a frontier area where there is limited data to constrain the interpretation of the hydrocarbon prospectivity. The Morant Basin provides the opportunity to undertake additional exploration activity, particularly the acquisition and processing of new (2D and possibly 3D) seismic data before a drilling commitment is confirmed.

Successful exploration drilling in the adjacent Walton Basin may provide additional data and information on the petroleum system in the Morant Basin. This may assist in constraining the petroleum system particularly the deeper intervals that have yet to be penetrated by a well. However, it is likely that the presence of the sandstone reservoirs interpreted in the Morant Basin are unlikely to be de-risked by drilling in the adjacent Walton Basin.

Appendix I
Input Parameters for Prospective Resource Estimates

Colibri Prospect					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	1,250	5,839	15,171	Weibull
NtG	Dec	0.30	0.50	0.80	Normal
Phi	Dec	0.06	0.17	0.24	Log Normal
Shc	Dec	0.60	0.75	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.20	1.35	1.50	Triangular
GOR	scf/bbl	300	600	900	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	155	996	4,019	1,697
TRR (oil)	MMBbl	33.4	223	966	406
TRR (sol gas)	Bscf	19	130	584	243

Oriole Prospect					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	278	906	2,950	Max Extreme
NtG	Dec	0.60		0.90	Normal
Phi	Dec	0.14	0.17	0.30	Log Normal
Shc	Dec	0.55	0.70	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.10	1.20	1.30	Triangular
GOR	scf/bbl	200	400	600	Triangular
Gas RF	Dec	0.12	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	199	752	1,9115	941
TRR (oil)	MMBbl	44.7	172	453	220
TRR (sol gas)	Bscf	17	67	184	88

Streamertail Prospect					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	1,385	3,752	10,165	Max Extreme
NtG	Dec	0.12		0.52	Normal
Phi	Dec	0.14	0.22	0.30	Normal
Shc	Dec	0.55	0.70	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.50	1.85	2.20	Triangular
GOR	scf/bbl	800	1,600	2,300	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	157	700	2,041	951
TRR (oil)	MMBbl	35.6	160	480	222
TRR (sol gas)	Bscf	53	244	758	347

Tody Prospect					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	101	346	1,183	Max Extreme
NtG	Dec	0.35		0.75	Normal
Phi	Dec	0.10	0.16	0.25	Normal
Shc	Dec	0.60	0.70	0.80	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.15	1.30	1.45	Triangular
GOR	scf/bbl	300	600	900	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	37.8	158	439	208
TRR (oil)	MMBbl	9.4	40.0	113	53.2
TRR (sol gas)	Bscf	5	23	68	32

Euphonia Prospect					
Parameter	**Units**	**P90**	**P50**	**P10**	**Dist**
GRV	MM m3	37	178	860	Max Extreme
NtG	Dec	0.40	0.55	0.75	Normal
Phi	Dec	0.10	0.16	0.24	Normal
Shc	Dec	0.60	0.70	0.80	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.15	1.30	1.45	Triangular
GOR	scf/bbl	300	600	900	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	**P50**	**P10**	**Mean**
STOIIP	MMBbl	26.3	114	314	149
TRR (oil)	MMBbl	6.5	28.8	81.0	38.3
TRR (sol gas)	Bscf	4	17	49	23

Thunderball Lead					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	939	7,355	16,266	Max Extreme
NtG	Dec	0.18		0.80	Normal
Phi	Dec	0.12	0.17	0.26	Normal
Shc	Dec	0.50	0.70	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.20	1.30	1.40	Triangular
GOR	scf/bbl	200	450	700	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	340	1,821	5,757	2,585
TRR (oil)	MMBbl	76.3	417	1,356	603
TRR (sol gas)	Bscf	32.3	181	616	271

Moonraker Lead					
Parameter	Units	P90	P50	P10	Dist
GRV	MM m3	727	3,605	7,761	Max Extreme
NtG	Dec	0.18	0.50	0.80	Normal
Phi	Dec	0.12	0.19	0.26	Normal
Shc	Dec	0.50	0.67	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.10	1.18	1.25	Triangular
GOR	scf/bbl	100	275	450	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	P50	P10	Mean
STOIIP	MMBbl	199	984	3,057	1,384
TRR (oil)	MMBbl	44.9	225	718	323
TRR (sol gas)	Bscf	11	59	199	89

Gaffney Cline

Moneypenny Lead					
Parameter	**Units**	**P90**	**P50**	**P10**	**Dist**
GRV	MM m3	786	2,041	3,984	Max Extreme
NtG	Dec	0.18	0.50	0.80	Normal
Phi	Dec	0.12	0.19	0.26	Normal
Shc	Dec	0.50	0.67	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.10	1.20	1.30	Triangular
GOR	scf/bbl	100	275	450	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	**P50**	**P10**	**Mean**
STOIIP	MMBbl	137	561	1,561	740
TRR (oil)	MMBbl	30.8	128	370	173
TRR (sol gas)	Bscf	8	34	103	48

Blofeld Lead					
Parameter	**Units**	**P90**	**P50**	**P10**	**Dist**
GRV	MM m3	555	1,801	3,686	Max Extreme
NtG	Dec	0.18	0.50	0.80	Normal
Phi	Dec	0.12	0.19	0.30	Normal
Shc	Dec	0.50	0.67	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.10	1.20	1.30	Triangular
GOR	scf/bbl	100	275	450	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	**P50**	**P10**	**Mean**
STOIIP	MMBbl	132	564	1,533	734
TRR (oil)	MMBbl	29.9	129	361	171
TRR (sol gas)	Bscf	8	34	102	47

Goldeneye Lead					
Parameter	**Units**	**P90**	**P50**	**P10**	**Dist**
GRV	MM m3	300	847	2,065	Max Extreme
NtG	Dec	0.18	0.50	0.80	Normal
Phi	Dec	0.12	0.19	0.26	Normal
Shc	Dec	0.50	0.67	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.10	1.20	1.35	Triangular
GOR	scf/bbl	200	400	600	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	**P50**	**P10**	**Mean**
STOIIP	MMBbl	185	612	1,465	744
TRR (oil)	MMBbl	41.1	140	346	174
TRR (sol gas)	Bscf	16	55	141	69

Jaws Lead					
Parameter	**Units**	**P90**	**P50**	**P10**	**Dist**
GRV	MM m3	201	560	1,111	Max Extreme
NtG	Dec	0.18	0.50	0.80	Normal
Phi	Dec	0.12	0.19	0.26	Normal
Shc	Dec	0.50	0.67	0.85	Normal
Oil RF	Dec	0.15	0.20	0.35	Triangular
FVF	rb/stb	1.20	1.50	1.80	Triangular
GOR	scf/bbl	450	1,000	1,500	Triangular
Gas RF	Dec	0.15	0.20	0.35	Triangular
		P90	**P50**	**P10**	**Mean**
STOIIP	MMBbl	29.8	124	351	166
TRR (oil)	MMBbl	6.7	28.3	82.4	38.6
TRR (sol gas)	Bscf	6	27	82	38

Appendix II
SPE PRMS Short Form Guide

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	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.
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

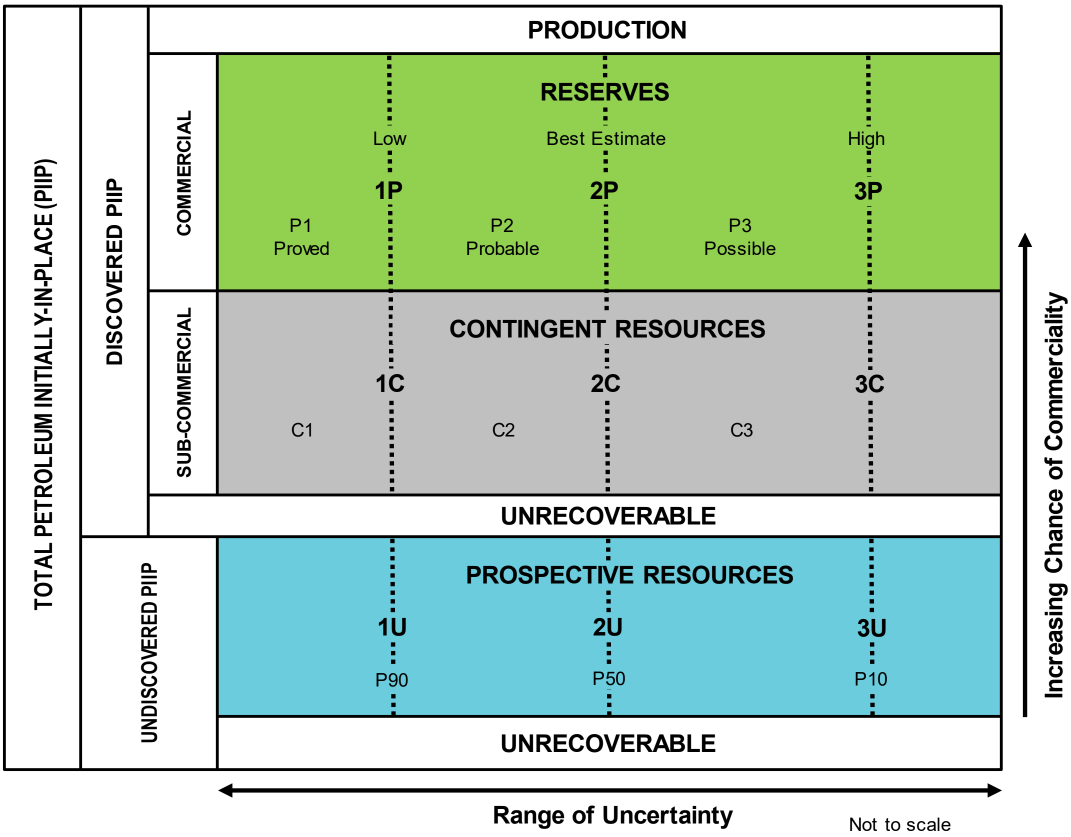


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY