Gaffney Cline

Audit of Reserves and Contingent Resources for Oil and Gas Assets in Romania as at 31st December 2022

Prepared for

Serinus Energy plc

February 2023

Gaffney Cline

Document Approval and Distribution

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Project Manager: _____ February 2023

Basil Al-Shamma, Principal Advisor

Reviewed by: _____ February 2023

Shane Hattingh, Technical Director

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Introduction

At the request of Serinus Energy plc (Serinus), Gaffney, Cline & Associates Limited (GaffneyCline) has performed an independent technical and economic audit of the Reserves and Contingent Resources in the Moftinu gas field in Romania, as at an Effective Date of 31st December 2022.

This report relates specifically and solely to the subject matter as defined in the scope of work, 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.

A glossary of abbreviations used in this report is contained in Appendix I.

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, 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 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 (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) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. 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 Serinus 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.

Definition of Reserves and Resources

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

Reserves are 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).

Contingent Resources are 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 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.

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".

GaffneyCline has not undertaken a site visit and inspection because it was not included in the scope of work. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. 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).

GaffneyCline is not aware of any potential changes in regulations applicable to these fields that could affect the ability of Serinus to produce the estimated reserves.

Use of Net Present Values

It should be clearly understood that the NPVs of future revenue potential of a petroleum property, such as those discussed in this report, do not represent GaffneyCline's opinion as to the market value of that property, nor any interest therein. In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e. that Reserves may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the reference NPVs presented herein.

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 Serinus. 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.

Executive Summary

Reserves Summary

On the basis of technical and other information made available, GaffneyCline hereby provides the following statement of Proved, Proved plus Probable and Proved plus Probable plus Possible gas and Condensate Reserves (Table 1). Reserves are assessed up until the expiry of the licence (end 2034).

Table 1: Reserves Net to Serinus as at 31st December 2022

(a) Gas

Country	Field	Gas Reserves (Bscf)		
		Proved	Proved plus Probable	Proved plus Probable plus Possible
Romania	Moftinu	1.64	2.70	4.23

(b) Condensate

Country	Field	Condensate Reserves (MBbl)		
		Proved	Proved plus Probable	Proved plus Probable plus Possible
Romania	Moftinu	0.42	0.67	1.02

Notes:

1. Gas Reserves have been quoted net of fuel and flare.
2. The reserves figures are based on forward production profiles.
3. Reserves Net to Serinus are Serinus' net economic entitlement under the Concession Agreement that governs the asset. This is 100% of gross Reserves as royalty is paid in cash and Serinus' working interest is 100%.

NPV Summary

Reference post-tax Net Present Values (NPVs) have been attributed to the Proved, Proved plus Probable, and Proved plus Probable plus Possible Reserves. The reference NPVs for these cases at discount rates of 7.5%, 10.0% and 12.5% are summarised in Table 2.

GaffneyCline's own 1Q 2023 oil and gas price scenario, adjusted for quality and location, has been used in preparing these NPVs. All NPVs quoted are those exclusively attributable to Serinus' Net Entitlement Reserves in the properties reviewed.

Table 2: Post-Tax NPV (US$ MM) of Future Cash Flow from Reserves Net To Serinus as at 31st December 2022

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
7.5	1.41	6.45	11.92
10.0	1.53	6.41	11.75
12.5	1.62	6.35	11.54

Notes:

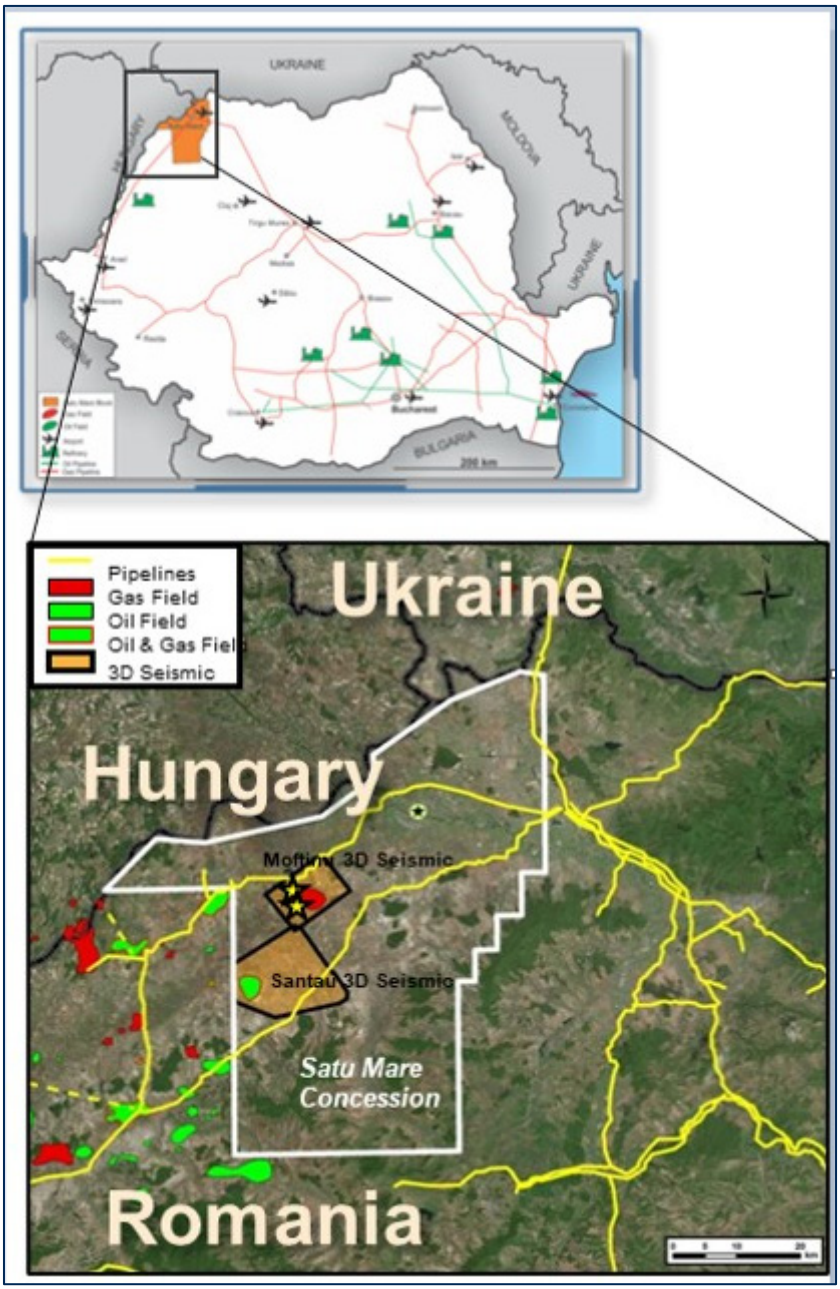
1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

Discussion

1 Background

Serinus acquired the Romanian Satu Mare concession as part of its acquisition of Winstar Resources in 2013. The concession is approximately 2,949 km^2 in size. The exploration block lies directly east of the Hungarian and south of the Ukrainian borders close to the town of Satu Mare (Figure 1).

Figure 1: Field Location



Source: Serinus

A 3D seismic survey was completed in 2012. The first of two commitment wells was drilled at Madaras-109, south of Moftinu, to test for oil in Miocene sands, but was unsuccessful. The second well, Moftinu-1000 (M-1000), was drilled in 2015 based on AVO-supported amplitude anomalies interpreted from the seismic survey. It discovered gas in several reservoir horizons of Pliocene age (from youngest to oldest: C1, B1, A3, A2.2, A2, A2 Lower and A1).

The Moftinu field has been developed with four wells to date, M-1003, M-1007, M-1004 and M-1008. Production commenced from M-1003 in April 2019 and from M-1007 in May 2019. Production from M-1004 was added in February 2020 and a 4th development well, M-1008, was drilled and came on stream in March 2021 as planned. To date, five of the seven reservoir horizons have been produced, with the C and B sands remaining un-perforated.

The wells are connected via a gas pipeline to the gas plant and thereafter to the Transgas pipeline, which is an export route into the local market.

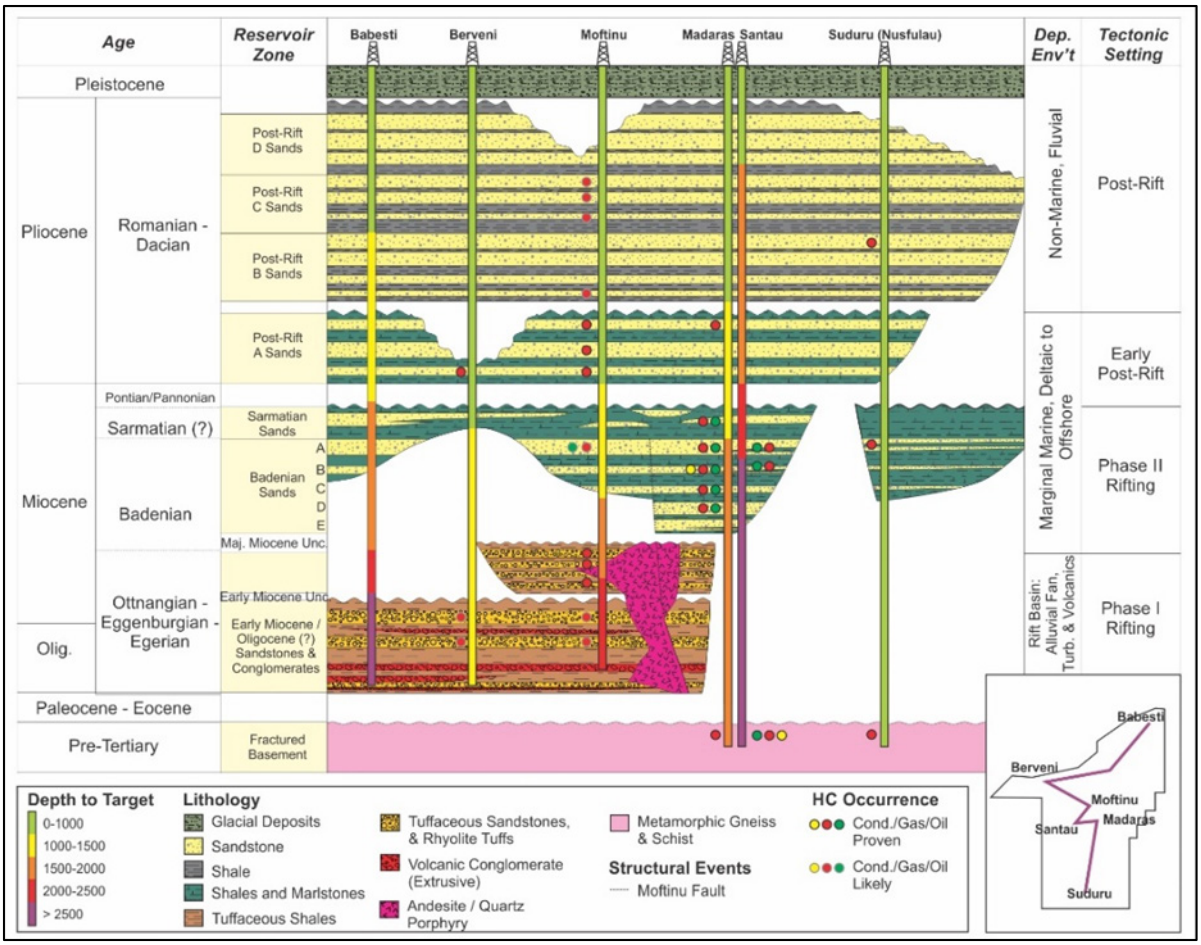
2 Geology

Technical data and supporting documentation were previously provided to GaffneyCline in the form of presentations, Excel spreadsheets, and an IHS Kingdom project to review volume estimates made by Serinus. The recently drilled well M-1008 came in close to prognosis (within 1% of prognosed depth) for all the reservoirs and hence the previous interpretations are still considered valid. Consequently, Serinus has not provided an update on structural interpretation and the only addition to the available geoscience database are the results of Well M-1008.

2.1 Regional Geology

The Moftinu Field is located on the Carei Uplift, between the Carei and Nisipeni Sub-Basins which form part of the Pannonian Basin. The Pannonian Basin comprises a number of Cenozoic extensional and transtensional sub-basins, developed in the area of the Greater Alpine-Carpathian fold and thrust belt. Subsidence in these basins resulted from strike slip movement along major NE-SW trending shear faults. Overall stratigraphy is shown in Figure 2.

Figure 2: Regional Stratigraphy



Source: Serinus

Basement comprises the Mesozoic and older succession, which represents deposition in the ancestral Rheic and Tethys Oceans, deformed in the Hercynian and Alpine orogenies. This is not relevant to the reservoir horizons discussed here, which are all of Pliocene age.

The Cenozoic sequence commences with units of Miocene age, which unconformably overlie Cretaceous and Paleogene sediments. The Miocene consists of sandstones alternating with marls and sandy marls, calcareous sandstones and shale. Further incremental subsidence led to deposition of the Pannonian Group. Initial deposition in the Late Miocene was of the distal clastics of the Endröd Formation, followed by a gradual shallowing-upward sequence controlled by shelf edge progradation from the northwestern to northeastern margin of the basin. Thus, distal turbidites of the Szalonta and Szolnok Formations were succeeded by slope deposits of the Algyö Formation, and thence by shelfal to delta-front deposits of the Ujfalu/Törtel Formations. These units are all Late Miocene in age, but diachronous in detail. The final phases of the Pannonian are alluvial plain deposits of the Zagyva Formation and range into the Pliocene. Hydrocarbon-bearing reservoirs of the Moftinu Field are present in Pliocene sandstone units, deposited in transitional littoral to deltaic settings, indicating good communication with viable hydrocarbon source kitchens in the Carei Sub-Basin.

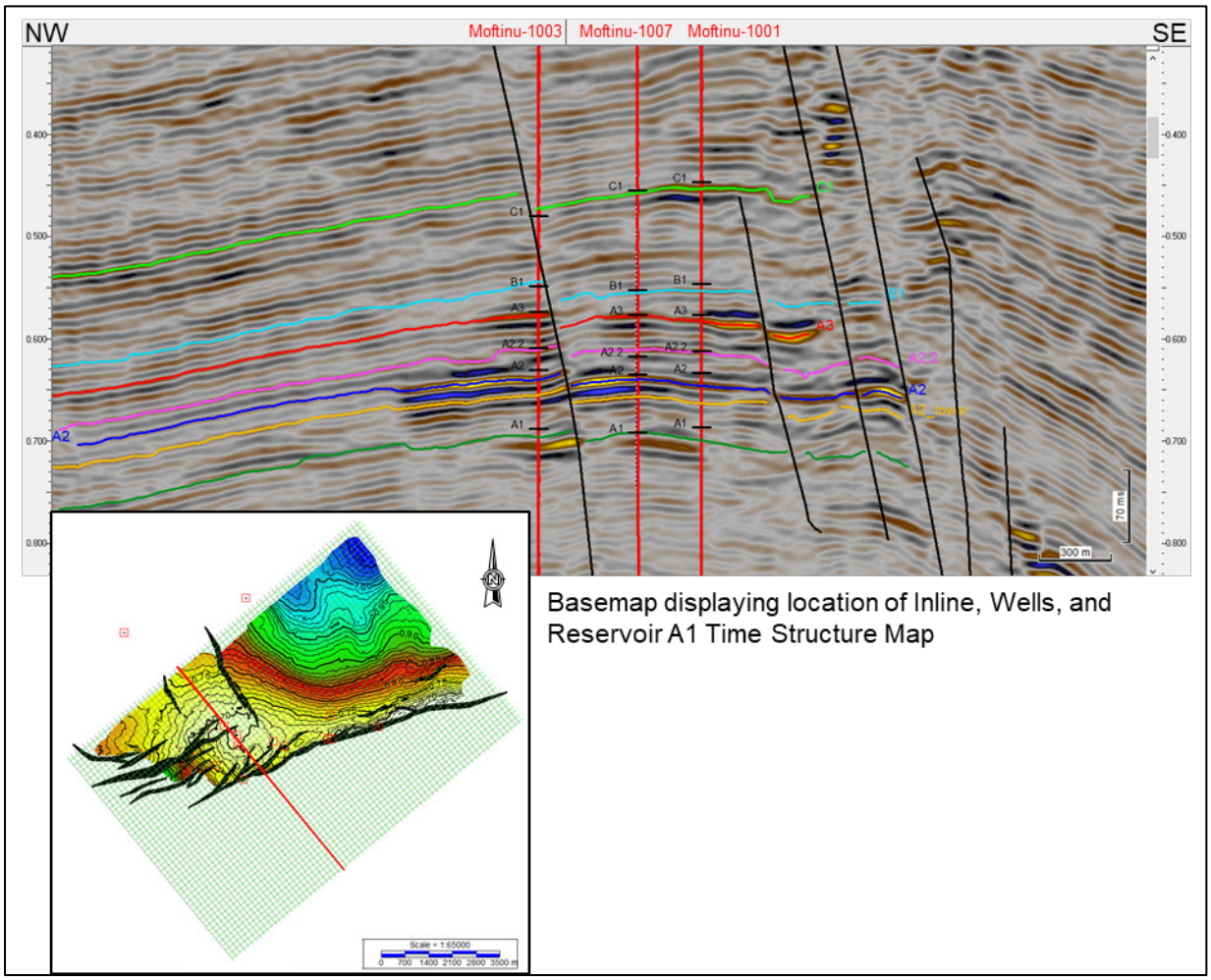
The sources of hydrocarbon within this region are at several levels ranging in age from Triassic to Miocene. The main source rocks are Badenian shales and marls, containing a mix of type II and locally type III kerogen.

The traps in the Pannonian Basin are structural, stratigraphic and combination. They are associated with normal faulting, local inversion, and compaction features over basement highs. Stratigraphic pinch-outs in fluvial, deltaic and turbidite sandstones are commonly observed within the Pannonian Basin. Seals are provided by fine-grained rocks of the Neogene basin fill.

2.2 Seismic Data

The Moftinu Field is covered by a 3D seismic survey, acquired in 2012 and with an areal extent of 78.57 km^2. GaffneyCline previously reviewed the provided seismic interpretation and considered it reasonable for the purpose of volumetric estimation. Overall quality of the seismic data is good. The reservoir intervals are well imaged on the seismic data. The seismic reflections are high amplitude and laterally continuous, which allows for a relatively confident structural interpretation to be made (Figure 3). Faults are also imaged well on the seismic dataset as vertically consistent reflector terminations. Amplitude anomalies conform to some extent to the structure and are thought to be an indicator of hydrocarbons as well as lithology.

Figure 3: NW-SE Seismic Line (Inline 459)

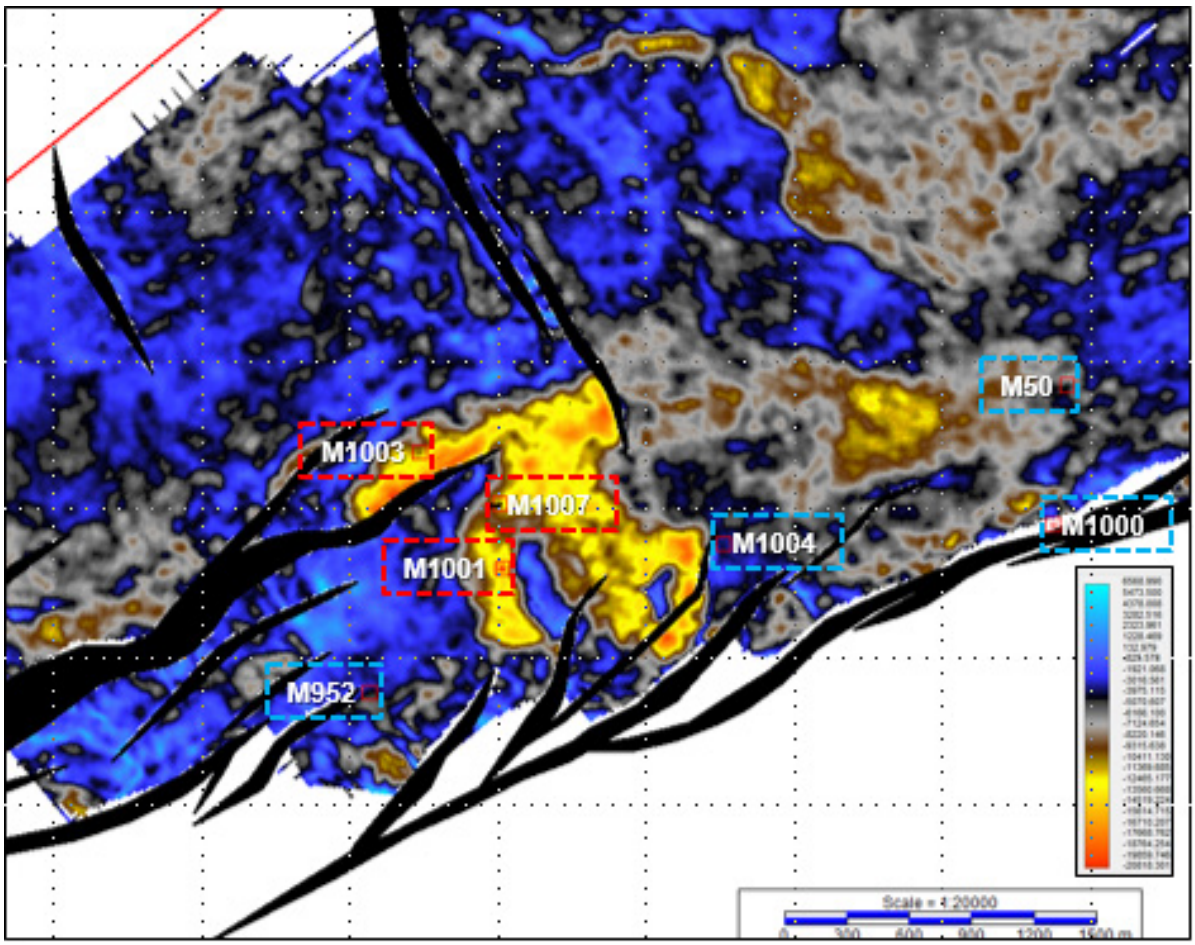


Source: GaffneyCline from Serinus Database (IHS Kingdom project)

There is however some inherent uncertainty in the time-depth conversion. The area around Well M-1001 displays relatively slower average velocities. This affects the resulting velocity maps used in depth conversion, including the extrapolation away from wells. Overall, however, GaffneyCline accepts the depth maps provided by Serinus as reasonable for the purpose of estimating gas initially in place (GIIP).

The trap at the Moftinu Field is a faulted 4-way dip closed structure, which displays seismic amplitude support, with most of the reservoir horizons displaying brighter seismic amplitudes within the western part of the field area (Figure 4). The amplitude map shown in Figure 4 is illustrative of the seismic response at the pay horizons.

Figure 4: Reservoir A1 Amplitude Anomaly



Source: Serinus

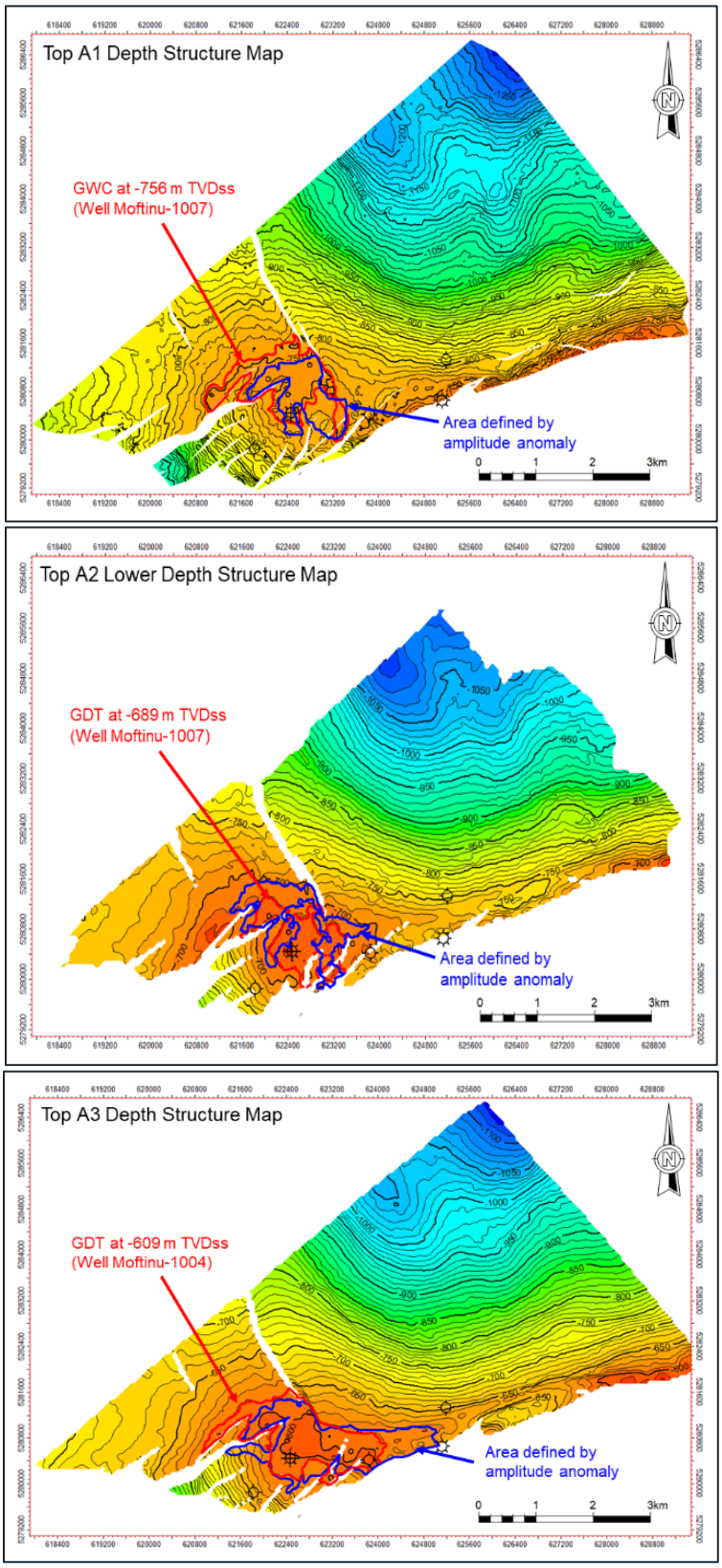
2.3 Petrophysics

The predominant reservoir lithologies are very fine to medium grained, well sorted, unconsolidated to consolidated quartz arenites which have been described from cuttings. The reservoir sandstones display good to excellent porosities. Core data are not available. Log analysis results in porosities between 20% and 34% and log permeabilities of about 300 mD are suggested. The results of the recently drilled well M-1008 are comparable to the other development wells. However, reservoir A1 displays a decrease in porosity with an average porosity of 15%, which is likely due to the presence of calcareous cement.

2.4 GIIP

Gross rock volumes (GRV) were independently calculated by GaffneyCline following a map based approach for each reservoir zone, between top and base reservoir surfaces and above the various fluid contacts. The volume defined by the gas-down-to (GDT) depths was assumed as the Low Case estimate. The High Case was defined based on reservoir thickness and area of amplitude anomaly. Figure 5 shows the top depth structure maps for each of the reservoir horizons, including the deepest identified contact and area of amplitude anomaly as provided by Serinus Energy.

Figure 5: Moftinu Field Top Depth Structure Maps for Each of the Reservoir Horizons



Source: GaffneyCline (from Serinus Energy database)

Serinus' reservoir parameters (net-to-gross (NTG) ratio, porosity and gas saturation) were reviewed and generally considered to be reasonable. GaffneyCline used these with the GRV estimates as inputs to a probabilistic (Monte Carlo) model for each of the reservoir horizons.

Reservoir properties were adjusted to reflect the GRV considered for volume estimation by GaffneyCline. Input parameters were derived from well averages based on log curves provided by Serinus Energy as part of the database. To create Low and High Case values, a variance of ±5% was applied to the Best Case NTG value, a variance of ±0.02 p.u. to the Best Case porosity value and a variance of ±10% to the Best Case gas saturation. GaffneyCline used these with the GRV estimates as inputs to a probabilistic (Monte Carlo) model for each of the reservoir horizons.

Table 3 summarises GaffneyCline's GIIP estimates for each of the reservoir intervals with a total Best Case GIIP of 31.6 Bscf. Serinus quotes a total Best Case GIIP of 29.5 Bscf which is within the range of the GIIP estimates shown. These estimates are unchanged from year-end 2020.

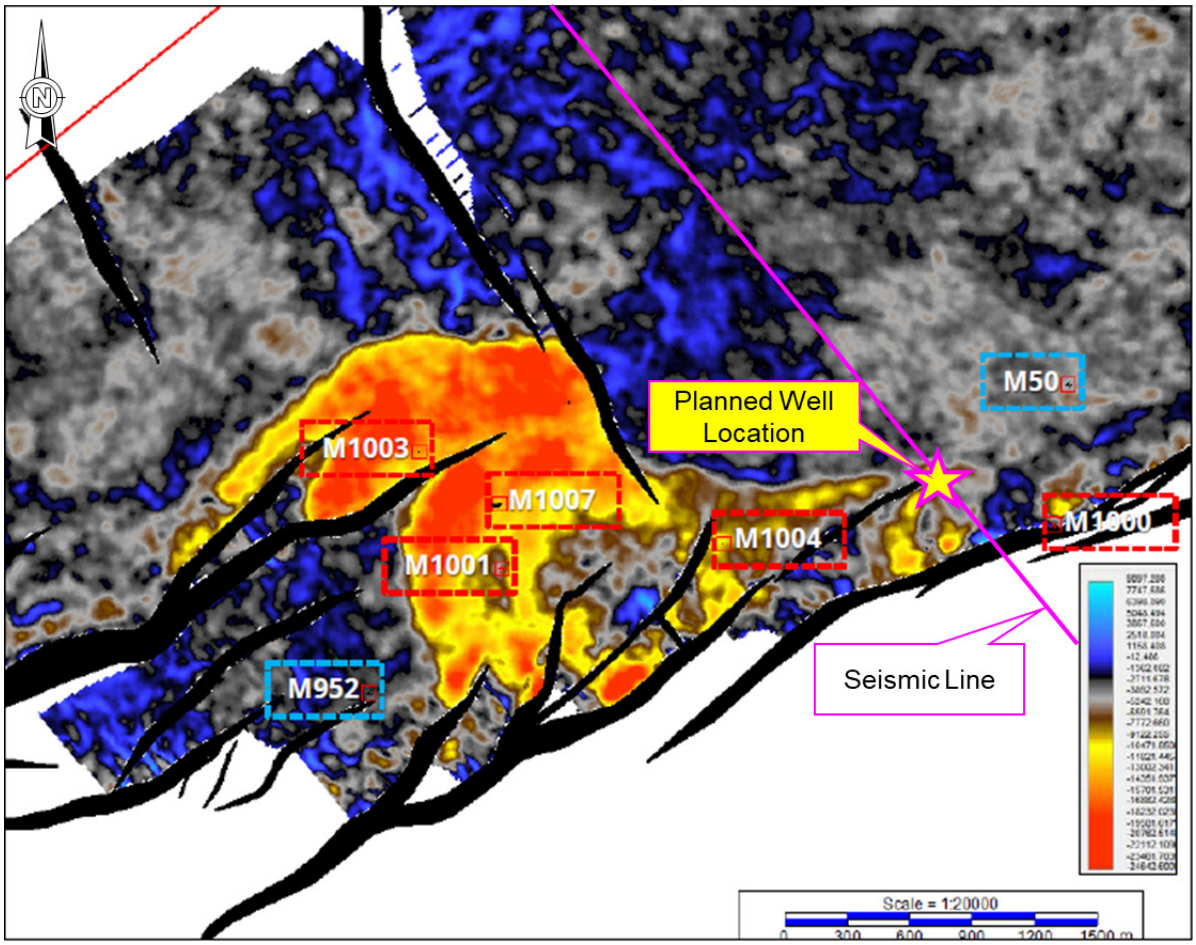
Table 3: Moftinu Field GIIP

Reservoir	GIIP (Bscf)		
	Low	Best	High
C1	3.3	4.8	7.0
B1	0.5	0.9	1.3
A3	6.3	8.5	11.5
A2.2	1.6	2.9	5.2
A2	3.7	5.2	7.3
A2 Lower	1.3	1.7	2.2
A1	4.8	7.6	12.0

2.5 Field Development

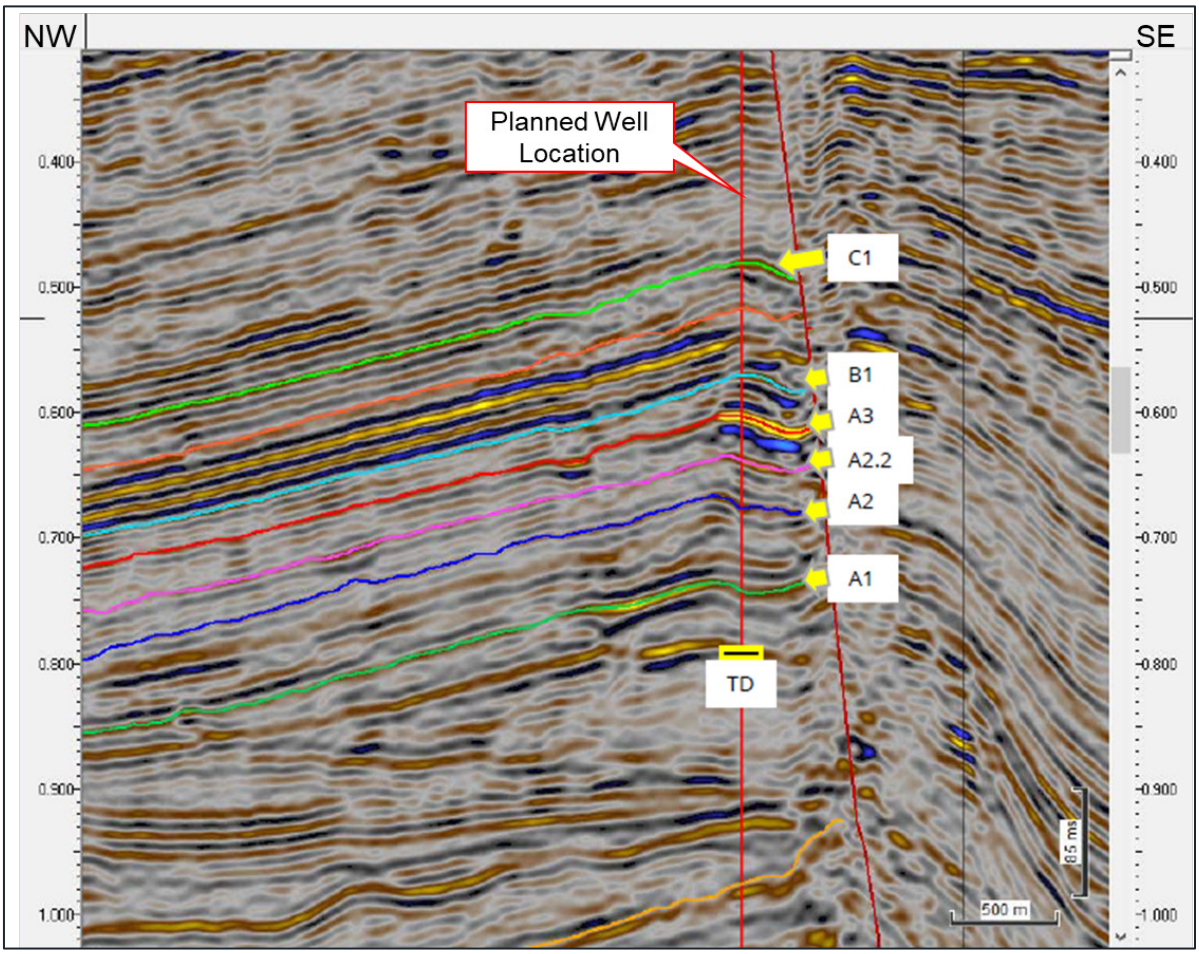
A fifth development well, Well M-1009 is planned to be drilled and placed on stream in November 2023. The well is situated between Wells M-1004 and M-1000. The well location is towards the south-east of the development wells, targeting a fault block south of the main field area. The current understanding is that the fault is not sealing due to the limited throw across the fault. The drilling location was selected based on the structural interpretation and bright amplitude response (Figure 6 and Figure 7).

Figure 6: Location Map, showing Amplitude Response at A2 Reservoir and Well Location



Source: Adapted from Serinus

Figure 7: Seismic Cross-Section at Well Location



Source: Adapted from Serinus

3 Reservoir Engineering

3.1 Introduction

Wells M-1001 and M-1002bis were drilled in 2015. M-1001 was drilled to a total depth of 1,453 m and was perforated in the A1, A2 and A3 sands. A well test flowed gas at 7.3 MMscfd and condensate at 18 bpd. M-1002bis was drilled to a total depth of 2,080 m TVD but failed to find hydrocarbons.

Following testing of M-1001, the well flowed gas during an uncontrolled well event from 22nd December 2017 to 6th January 2018. During this period, it is estimated that the well flowed at 1.52 MMscfd with 0.071%/day decline, implying a total flow of c. 24 MMscf of gas. As a result of this event, the well was not brought into production and has been plugged and abandoned.

In May 2018, well M-1007 was drilled to a depth of 1,459.7 m TVD. It was tested and produced from the A1, A2 and A3 sands with a gas rate of 5.7 MMscfd. M-1003 was drilled in August 2018 and achieved a similar gas rate of approximately 5.7 MMscfd when tested and produced from the A1, A2L and A2 sands.

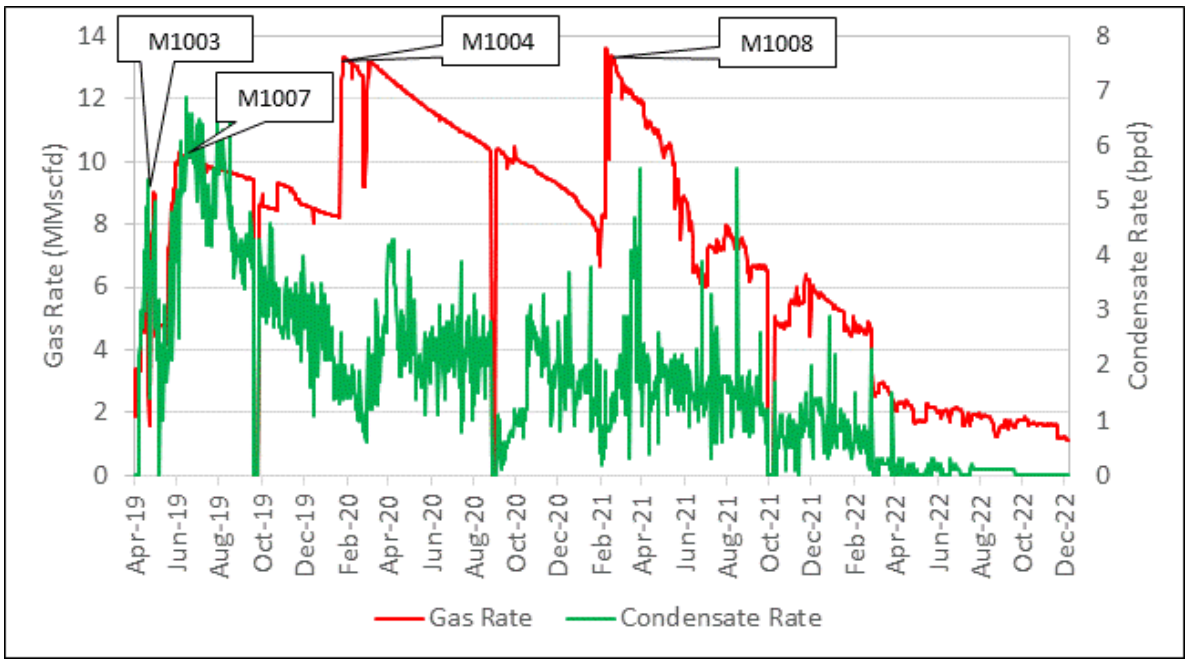
3.2 Production History

In April 2019, M-1003 commenced commercial gas production, followed in May 2019 by M-1007. In 2020, M-1004 was successfully drilled and tested at 6 MMscfd before the well was brought onto production in February 2020. M-1008 was spudded in January 2021 and was drilled to a depth of 1002 m TVD. It was tested and produced from the A1, A2, A3 and B1 sands. The A1 and B1 sands did not produce any gas and a plug was set above the A1 sand. The A2 and A3 sands produced a gas rate of 1.7 MMscfd, which was significantly lower than expected.

Five developed intervals in the main A sands (A1, A2L, A2, A2-2, A3) are currently producing. Undeveloped intervals in the shallow reservoirs (B and C sands) will be considered for future development.

Three wells, M-1003, M-1007 and M-1004 were producing at an average gas rate of 1.6 MMscfd and average condensate rate of 0.1 bpd as of 31st December 2022. This is much lower than was expected at year-end 2022, due to steeper than expected production decline in the existing wells and the poorer than expected performance and eventual shut in of M-1008. The total gas produced to the end of 2022 is approximately 9.2 Bscf. The gas and condensate production history is shown in Figure 8. The current well status and current cumulative production of each well is shown in Table 4.

Figure 8: Moftinu Field Gas and Condensate Production



Source: GaffneyCline from Serinus production data

Table 4: Moftinu Field Well Status

Well Name	Produced Gas to end 2022 (Bscf)	Well Status at 31st December 2022
M-1000	0.007	Plugged and Abandoned
M-1001	0.024	Suspended Gas Well
M-1002	-	Plugged and Abandoned
M-1003	3.25	Producing Gas Well
M-1007	3.26	Producing Gas Well
M-1004	1.94	Producing Gas Well
M-1008	0.72	Shut-in Gas Well
Total	**9.20**	

3.3 Future Development

An additional well (M-1009) is planned to be drilled and put on stream in November 2023 (see Section 2.5). Compression was installed in December 2021 for M-1003 and in February 2022 for M-1007, July 2022 for M-1004 to maintain production. The compression is designed to lower the wellhead pressure from 500 psi to 285 psi. There is potential to review planned compression in support of production optimisation. Zone changes for the currently producing three wells are planned for July, August and September 2024 in M-1004, M-1007 and M-1003 respectively.

Total CAPEX for these activities is estimated by Serinus at US$3.62 MM, of which US$3.12 MM is for the additional well and the rest is expenditure towards the gas plant. Future

OPEX has been estimated based on fixed monthly OPEX of US$60,000 (US$100,000 only in 2023 including workover costs), and variable OPEX of US$2.50/Mscf. An abandonment cost estimate of US$3.59 MM was used (2023 real terms). GaffneyCline has reviewed these cost estimates and accepts them as reasonable.

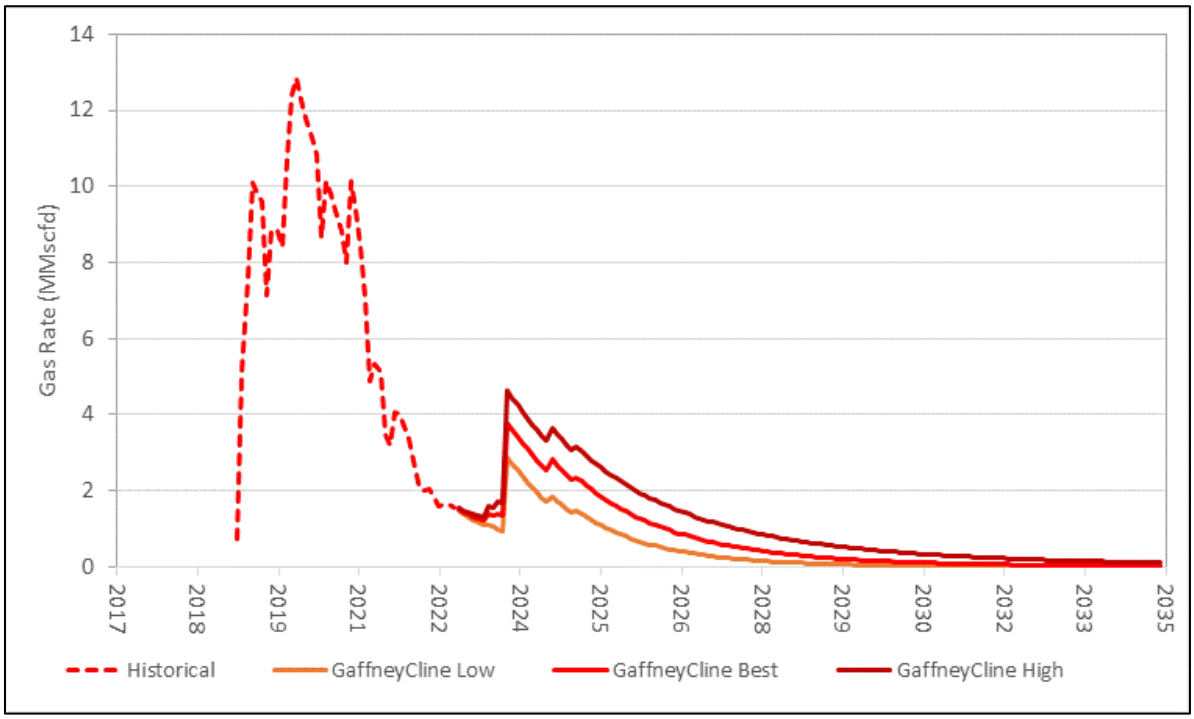
3.4 Production Forecast and Ultimate Recovery

GaffneyCline used Decline Curve Analysis (DCA) to forecast the future production rate for the Moftinu field. The DCA was done on a well by well basis and summed for the field production profile. The decline rate was altered to determine Low and High profiles around the Best estimate case.

Figure 9 shows the historical production and the Low, Best and High gas production forecasts for Moftinu. The increase in gas production in November 2023, is due to well M-1009 coming on stream. The increase in gas production rate in July, August and September 2024 is due to zone changes in M-1004, M-1007 and M-1003 respectively.

A constant CGR based on an average historical CGR for each well was used to determine the condensate rates.

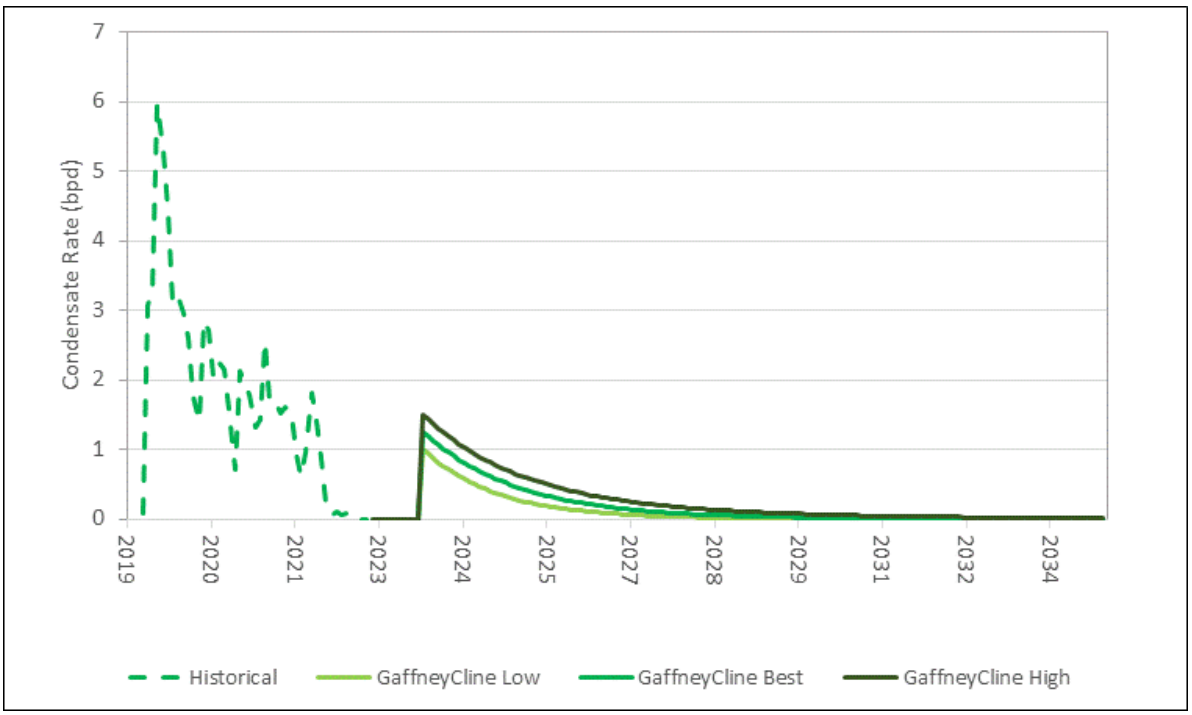
Figure 9: Moftinu Field Gas Production History and Forecast



Notes:

1. No economic cut off has been applied to the profiles shown here.
2. The gas volumes are wellhead volumes and have not been adjusted for shrinkage, fuel and flare.
3. The production history excludes production from well M-1001.

Figure 10: Moftinu Field Condensate Production History and Forecast



Notes:

1. No economic cut off has been applied to the profiles shown here.
2. The production history excludes production from well M-1001.

The estimates of the ultimate technically recoverable gas volumes by the end of the Concession in December 2034, and the total remaining technically recoverable gas volumes over the forecast period from 2023 through to end 2034, are shown in Table 5.

The gross gas and condensate technical production and cost profiles are shown in Appendix III.

Table 5: Forecast Technically Recoverable Gas Resources as at 31st December 2022

	Ultimate Technically Recoverable Gas (Bscf)			Remaining Technically Recoverable Gas (Bscf)		
	Low	Best	High	Low	Best	High
Developed	10.3	11.1	12.0	1.1	1.9	2.8
Undeveloped	0.9	1.4	2.1	0.9	1.4	2.1
Total	**11.2**	**12.5**	**14.1**	**2.0**	**3.3**	**4.9**

Notes:

1. Historical gas production in the field by end-2022 is 9.20 Bscf.
2. The volumes shown here are those estimated to be technically recoverable before the end of the Concession Agreement at end 2034. No economic cut off has been applied to the volumes.
3. Remaining volumes are as of 31st December 2022.
4. The forecast includes developed wells M-1003, M1004, M-1007 and undeveloped well M-1009.
5. The gas volumes are wellhead volumes and have not been adjusted for shrinkage, fuel and flare.
6. Numbers may not add up due to rounding.

3.5 Contingent Resources

Contingent Resources are considered from behind pipe in the C1 and B1 layers and are shown in Table 6. A decision is yet to be made on the development of these intervals.

Table 6: Gas Contingent Resources Net to Serinus as at 31st December 2022

	Gas Contingent Resources (Bscf)		
	1C	2C	3C
Undeveloped Behind Pipe (B1/C1 Layers)	2.5	4.3	7.0

Notes:

1. Contingent Resources Net to Serinus are Serinus' net economic entitlement under the Concession Agreement that governs the asset. This is 100% of gross Contingent Resources as royalty is paid in cash and Serinus working interest is 100%.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the field/project may not be developed in the form envisaged or not at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.

4 Economic Analysis

GaffneyCline has conducted an economic limit test (ELT) to assess Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) Reserves for the Moftinu field in Romania. The economic limit (or economic cut-off) is defined as the time when the maximum cumulative net cash flow occurs for a project; beyond this time, the net operating cash flows are negative.

These assessments have been based upon GaffneyCline's understanding of the fiscal and contractual terms governing the asset, and the various economic and commercial assumptions described herein. GaffneyCline has not had access to the Romanian concession agreements but Serinus has represented that its economic model, which was made available to GaffneyCline, replicates the workings of the concession contracts.

The effective date of the evaluation is 31st December 2022. All economic calculations have been performed on an annual basis.

Cash flow results for the Moftinu field for each Reserves case are shown in Appendix IV.

4.1 Oil and Gas Prices

GaffneyCline's 1Q 2023 scenario has been used for the economic assessments conducted herein.

GaffneyCline understands that gas from Moftinu is not subject to a Govt regulated gas price or a price cap and a Gas Sales Agreement (GSA) is in place for up to 5 years at market prices linked to CEGH VTP (Central European Gas Hub Virtual Trading Point) price. Gas marketing fee of 8% was used.

The UK National Balancing Point (NBP) was used as a proxy for CEGH VTP price forecast because the UK and European gas and electricity markets are linked. Therefore GaffneyCline's 1Q 2023 NBP scenario has been used as a proxy for VTP (Table 7).

Table 7: GaffneyCline 1Q 2023 Price Scenario

Year	NBP Gas Price (US$/MMBtu)	Brent Crude Price (US$/Bbl)
2023	24.28	83.83
2024	23.59	78.99
2025	19.03	80.00
2026	13.00	81.60
Thereafter	+2% per annum	+2% per annum

Condensate is assumed to be sold at 92% of the Brent crude price shown in Table 7.

4.2 Contract and Fiscal Terms

The Moftinu field lies in the Satu Mare Concession, which is governed by a Concession Agreement that expires in May 2034. Serinus holds a 100% interest in the Concession.

The fiscal regime is tax/royalty. The Royalty rate varies based on quarterly field production from 3.5% to 13.0% for gas and 3.5% to 13.5% for oil, respectively (Table 8). Royalty is paid in cash.

Table 8: Royalty Rates

Quarterly Gas Production (in MMm^3)	Royalty Rate (%)
<10	3.5%
10-50	7.5%
50-200	9.0%
>200	13.0%
Quarterly Oil Production (in Mt)	**Royalty Rate (%)**
<10	3.5%
10-20	5.0%
200-100	7.0%
>100	13.5%

Notes:

1. Gas production is in million m^3.
2. Oil production is in thousand tonnes.

Other taxes and charges include:

- ANRE Fee: payable on all sales gas volumes at 0.168 RON/MWh.
- Ad-Valorem Tax: payable on all oil and condensate revenues at 0.5%.
- Supplementary Tax: payable when gas prices are above certain price thresholds. Gas revenue at prices above 47.5 RON/MWh and up to a maximum of 85 RON/MWh is considered supplementary revenue and is taxed at 60%. Additionally, gas revenue at prices above 85 RON/MWh is taxed at 80%. Royalties and development CAPEX up to 30% are permissible deductions for supplementary tax.
- Corporate Tax: payable at a rate of 16%. All capital expenditures are depreciated on a unit-of-production (UOP) basis; i.e. the ratio of production to remaining recoverable reserves/resources. Capital depreciation, operating costs, royalties, and fees and supplementary tax payments are tax-deductible. A depreciation allowance opening balance of US$31.60 MM (2023) and Losses Carried Forward Balance of US$0.84 MM (2023) was used in the tax calculation.

An exchange rate of 4.7 RON/US$ and a conversion factor of 0.29 MWh/Mscf (Megawatt-hour/Thousand scf) have been used.

4.3 Results of Economic Analysis

The economic limit was found to occur at end 2026 in the Proved case, end 2027 in the Proved plus Probable case and end 2030 in the Proved plus Probable plus Possible cases. Resulting Reserves of gas and condensate are reported in the Executive Summary section in Table 1, and the corresponding NPVs in Table 2.

As royalty is payable in cash, it has not been deducted from the Reserves net to Serinus, which are therefore equal to the gross field Reserves as Serinus holds a 100% interest.

4.4 Price Sensitivity Analysis

A sensitivity analysis was conducted using the forward price curves of Front-Month TTF Futures and Brent Crude Futures as on 1 Jan 2023. This alternative price scenario was found to have no impact on Reserves in the low, mid, or high cases. NPV10 of the 2P case was found to be 12% higher compared the base case price scenario.

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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)

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Appendix II
SPE PRMS 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 2018 (v. 1.03)

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 2018 (v. 1.03)) 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 commercial 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. 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

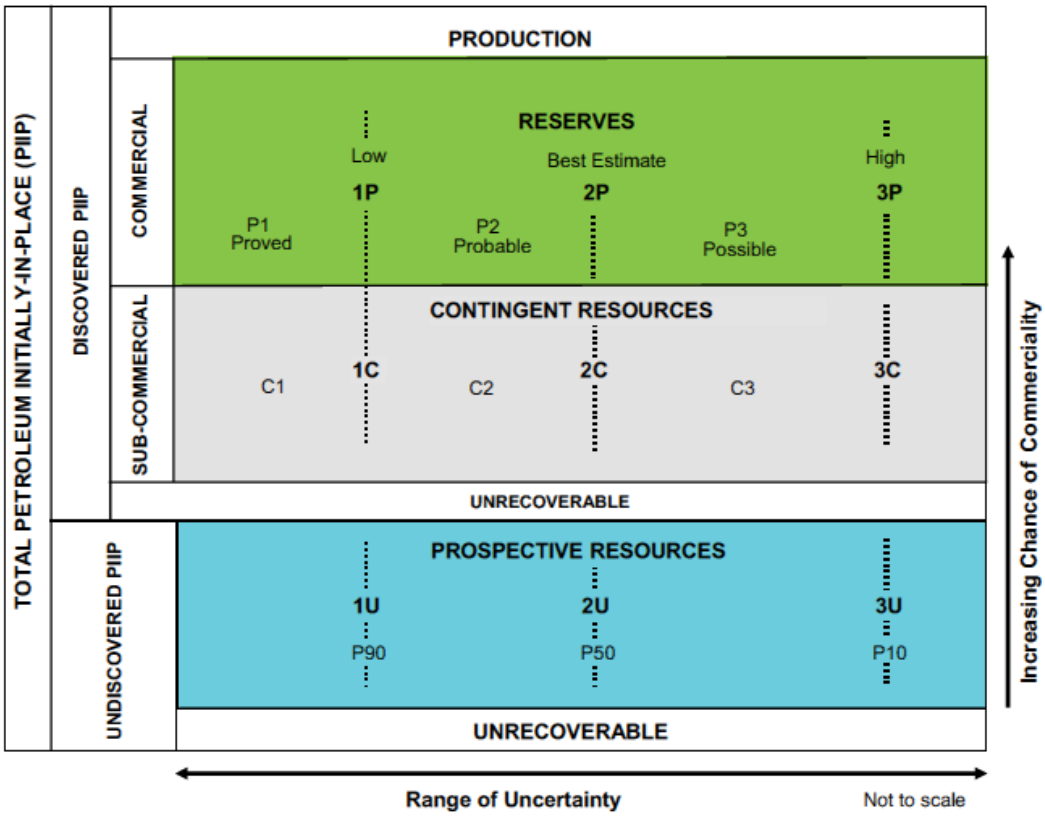
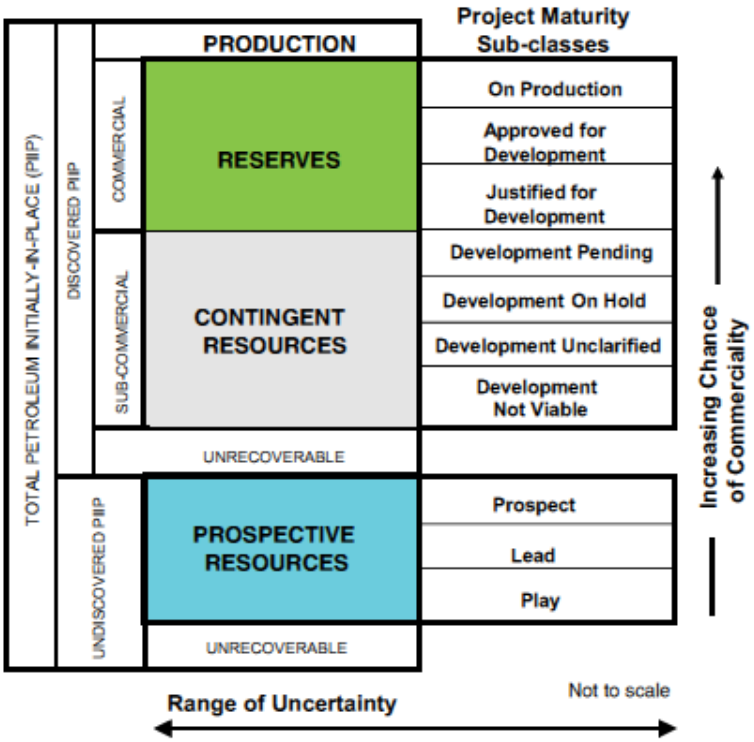


Figure 2.1—Sub-classes based on project maturity



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Appendix III
Gross Gas and Condensate Production Volumes and Cost Profiles

Table AIII.1: Gross Gas and Condensate Production Volumes and Cost Profiles - Low Case

Gross Production and Cost Profiles - Low Case				
Year	Gas	Condensate	CAPEX	OPEX
	(Bscf)	(MBbl)	(US$ MM)	(US$ MM)
2023	0.51	0.06	3.22	2.47
2024	0.65	0.22	0.10	2.35
2025	0.34	0.10	0.10	1.57
2026	0.14	0.04	0.11	1.07
2027	0.04	0.02	0.11	0.83
2028	-	-	-	
2029	-	-	-	
2030	-	-	-	
2031	-	-	-	
2032	-	-	-	
2033	-	-	-	
2034	-	-	-	
Total	**1.68**	**0.44**	**3.64**	**8.28**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Economic cut off has not been applied to the volumes.
3. Totals show technically recoverable volumes as of 31st December 2022 to 31st December 2034.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. The condensate volumes and costs have been cut off when all gas volumes are fuel and flare.
6. Costs shown are in 2023 Real terms.
7. Numbers may not add up due to rounding.

Table AIII.2: Gross Gas and Condensate Production and Cost Profiles – Best Case

Gross Production and Cost Profiles - Best Case				
Year	Gas	Condensate	CAPEX	OPEX
	(Bscf)	(MBbl)	(US$ MM)	(US$ MM)
2023	0.61	0.07	3.22	2.73
2024	0.97	0.31	0.10	3.15
2025	0.62	0.16	0.10	2.26
2026	0.33	0.08	0.11	1.54
2027	0.17	0.04	0.11	1.15
2028	0.08	0.02	-	0.92
2029	0.03	0.01	-	0.79
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
Total	**2.81**	**0.70**	**3.64**	**12.54**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Economic cut off has not been applied to the volumes.
3. Totals show technically recoverable volumes as of 31st December 2022 to 31st December 2034.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel, and flare.
5. The condensate volumes and costs have been cut off when gas all volumes are fuel and flare.
6. Costs shown are in 2023 Real terms.
7. Numbers may not add up due to rounding.

Table AIII.3: Gross Gas and Condensate Production and Cost Profiles – High Case

Gross Production and Cost Profiles - High Case				
Year	Gas	Condensate	CAPEX	OPEX
	(Bscf)	(MBbl)	(US$ MM)	(US$ MM)
2023	0.70	0.09	3.22	2.95
2024	1.27	0.39	0.10	3.88
2025	0.89	0.22	0.10	2.94
2026	0.56	0.13	0.11	2.12
2027	0.36	0.08	0.11	1.61
2028	0.23	0.05	-	1.29
2029	0.15	0.03	-	1.08
2030	0.09	0.02	-	0.95
2031	0.05	0.01	-	0.85
2032	0.03	0.01	-	0.79
2033	0.01	0.01	-	0.74
2034	-	-	-	-
Total	**4.32**	**1.05**	**3.64**	**19.20**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Economic cut off has not been applied to the volumes.
3. Totals show technically recoverable volumes as of 31st December 2022 to 31st December 2034.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
8. The condensate volumes and costs have been cut off when all gas volumes are fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

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Appendix IV
Summary of Cash Flow Analysis

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Table AIV.1: Serinus Net Working Interest Cash Flow – Proved Case

Field:	Moftinu Low	
Case:		
	Initial	*Final*
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	16.88	0.89
5.0%	16.21	1.27
7.5%	15.88	1.41
10.0%	15.55	1.53
12.5%	15.22	1.62
15.0%	14.91	1.69

Period Beginning	Condensate Production MMBbl	Condensate Price US$/Bbl	Gas Production BCF	Gas Price US$/MCF	Field Revenue US$ MM	Royalty US$ MM	Net Revenue US$ MM	Contractor Revenue US$ MM	Expl&Appr Costs US$ MM	Capital Costs US$ MM	Aband Costs US$ MM	Operating Costs US$ MM	Production Taxes US$ MM	Pre Tax NCF US$ MM	Supplementary Tax US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-23	0.00	77.12	0.51	22.34	11.34	0.40	10.94	10.94	-	3.22	-	2.47	0.01	5.25	5.59	-	- 0.35
Jan-24	0.00	72.67	0.65	21.70	14.13	0.49	13.64	13.64	-	0.10	-	2.39	0.01	11.13	6.93	-	4.20
Jan-25	0.00	73.60	0.34	17.51	5.99	0.21	5.78	5.78	-	0.11	-	1.64	0.00	4.03	2.79	-	1.24
Jan-26	0.00	75.07	0.14	11.96	1.66	0.06	1.60	1.60	-	0.11	-	1.13	0.00	0.35	0.68	-	- 0.32
Jan-27	-	76.57	-	12.20	-	-	-	-	-	-	3.89	-	-	- 3.89	-	-	- 3.89
Jan-28	-	78.10	-	12.44	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-29	-	79.67	-	12.69	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-30	-	81.26	-	12.95	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-31	-	82.89	-	13.20	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-32	-	84.54	-	13.47	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-33	-	86.23	-	13.74	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-34	-	87.96	-	14.01	-	-	-	-	-	-	-	-	-	-	-	-	-
														-			-
Totals (>01-Jan-23):	**0.00**	**MMBbl**	**1.64**	**BCF**	**33.11**	**1.16**	**31.95**	**31.95**	**-**	**3.54**	**3.89**	**7.63**	**0.02**	**16.88**	**15.99**	**-**	**0.89**
Entitlements (>01-Jan-23):	**0.00**	**MMBbl**	**1.64**	**BCF**													

Notes:

1. Cashflows are shown up to the Economic Limit only.
2. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. All costs have been inflated at 2%.

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Table AIV.2: Serinus Net Working Interest Cash Flow – Proved plus Probable Case

Field:	Moftinu Best	
Case:		
	Initial	*Final*
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	30.98	6.38
5.0%	29.17	6.46
7.5%	28.31	6.45
10.0%	27.49	6.41
12.5%	26.70	6.35
15.0%	25.95	6.27

Period Beginning	Condensate		Gas		Field Revenue	Royalty	Net Revenue	Contractor Revenue	Expl&Appr Costs	Capital Costs	Aband Costs	Operating Costs	Production Taxes	Pre Tax NCF	Supplementary Tax	Corporate Tax	Post Tax NCF
	Production MMBbl	Price US$/Bbl	Production BCF	Price US$/MCF	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
Jan-23	0.00	77.12	0.61	22.34	13.67	0.48	13.19	13.19	-	3.22	-	2.73	0.01	7.23	6.75	-	0.49
Jan-24	0.00	72.67	0.97	21.70	21.12	0.74	20.38	20.38	-	0.10	-	3.21	0.01	17.05	10.35	-	6.70
Jan-25	0.00	73.60	0.62	17.51	10.80	0.38	10.42	10.42	-	0.11	-	2.35	0.01	7.96	5.03	-	2.92
Jan-26	0.00	75.07	0.33	11.96	3.95	0.14	3.81	3.81	-	0.11	-	1.64	0.00	2.05	1.61	-	0.44
Jan-27	0.00	76.57	0.17	12.20	2.08	0.07	2.01	2.01	-	0.12	-	1.24	0.00	0.65	0.85	-	- 0.21
Jan-28	-	78.10	-	12.44	-	-	-	-	-	-	3.96	-	-	- 3.96	-	-	- 3.96
Jan-29	-	79.67	-	12.69	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-30	-	81.26	-	12.95	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-31	-	82.89	-	13.20	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-32	-	84.54	-	13.47	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-33	-	86.23	-	13.74	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-34	-	87.96	-	14.01	-	-	-	-	-	-	-	-	-	-	-	-	-
														-			-
Totals (>01-Jan-23):	**0.00**	**MMBbl**	**2.70**	**BCF**	**51.61**	**1.81**	**49.80**	**49.80**	**-**	**3.66**	**3.96**	**11.17**	**0.03**	**30.98**	**24.60**	**-**	**6.38**
Entitlements (>01-Jan-23):	**0.00**	**MMBbl**	**2.70**	**BCF**													

Notes:

1. Cashflows are shown up to the Economic Limit only.
2. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. All costs have been inflated at 2%.

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Table AIV.3: Serinus Net Working Interest Cash Flow – Proved plus Probable plus Possible Case

Field:	Moftinu High	
Case:		
	Initial	*Final*
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	47.38	11.94
5.0%	44.06	12.02
7.5%	42.49	11.92
10.0%	40.99	11.75
12.5%	39.56	11.54
15.0%	38.21	11.30

Period Beginning	Condensate		Gas		Field	Royalty	Net	Contractor	Expl&Appr	Capital	Aband	Operating	Production	Pre Tax	Supplementary	Corporate	Post Tax
	Production	Price	Production	Price	Revenue		Revenue	Revenue	Costs	Costs	Costs	Costs	Taxes	NCF	Tax	Tax	NCF
	MMBbl	US$/Bbl	BCF	US$/MCF	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
Jan-23	0.00	77.12	0.70	22.34	15.64	0.55	15.09	15.09	-	3.22	-	2.95	0.01	8.91	7.72	-	1.20
Jan-24	0.00	72.67	1.27	21.70	27.49	0.96	26.53	26.53	-	0.10	-	3.96	0.01	22.45	13.48	-	8.97
Jan-25	0.00	73.60	0.89	17.51	15.58	0.55	15.04	15.04	-	0.11	-	3.06	0.01	11.86	7.26	-	4.59
Jan-26	0.00	75.07	0.56	11.96	6.70	0.23	6.46	6.46	-	0.11	-	2.25	0.01	4.10	2.73	-	1.37
Jan-27	0.00	76.57	0.36	12.20	4.36	0.15	4.21	4.21	-	0.12	-	1.74	0.00	2.34	1.79	-	0.55
Jan-28	0.00	78.10	0.23	12.44	2.86	0.10	2.76	2.76	-	-	-	1.43	0.00	1.33	1.19	-	0.14
Jan-29	0.00	79.67	0.15	12.69	1.85	0.06	1.78	1.78	-	-	-	1.22	0.00	0.56	0.77	-	- 0.21
Jan-30	0.00	81.26	0.09	12.95	1.17	0.04	1.13	1.13	-	-	-	1.09	0.00	0.04	0.49	-	- 0.45
Jan-31	-	82.89	-	13.20	-	-	-	-	-	-	4.21	-	-	- 4.21	-	-	- 4.21
Jan-32	-	84.54	-	13.47	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-33	-	86.23	-	13.74	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan-34	-	87.96	-	14.01	-	-	-	-	-	-	-	-	-	-	-	-	-
														-			-
Totals (>01-Jan-23):	**0.00**	**MMBbl**	**4.23**	**BCF**	**75.63**	**2.65**	**72.99**	**72.99**	**-**	**3.66**	**4.21**	**17.70**	**0.04**	**47.38**	**35.43**	**-**	**11.94**
Entitlements (>01-Jan-23):	**0.00**	**MMBbl**	**4.23**	**BCF**													

Notes:

1. Cashflows are shown up to the Economic Limit only.
2. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. All costs have been inflated at 2%.