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

Prepared for

Serinus Energy plc

February 2023

Gaffney Cline

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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 Sabria and Chouech Es Sadia Concessions in Tunisia, as at an Effective Date of 31st December 2022.

In 2022, Serinus offered a work programme to the Tunisian regulator related to the Ech Chouech (EC-1) well, to enable the continuance of the Ech Chouech licence which is adjacent to (and tied into) the Chouech Es Saida field. The regulator declined the offer and consequently, Serinus has no further rights to Ech Chouech production at this time.

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 oil and gas Reserves (Table 1). Reserves are assessed up until the expiry of the Concession Agreements in 2043 and 2042 for Sabria and Chouech Es Sadia respectively. This includes a 15-year extension expected to be granted in each case.

In 2022, Serinus offered a work programme to the Tunisian regulator related Ech Chouech (EC-1) well, to enable the continuance of the Ech Chouech licence which is adjacent to (and tied into) the Chouech Es Saida field. The regulator declined the offer and consequently, Serinus has no further rights to Ech Chouech production at this time.

Table 1: Summary of Reserves as at 31st December 2022

(a) Oil and Condensate

Concession Area	Gross Oil (MMBbl)			Serinus' Working Interest Fraction (MMBbl)			Serinus' Net Entitlement Oil (MMBbl)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible
Sabria	4.77	9.94	15.03	2.15	4.47	6.76	1.92	3.94	5.87
Chouech Es Saida	0.16	0.47	0.70	0.16	0.47	0.70	0.13	0.40	0.59
Total	**4.93**	**10.40**	**15.73**	**2.31**	**4.94**	**7.46**	**2.05**	**4.34**	**6.47**

(b) Gas

Concession Area	Gross Gas (Bscf)			Serinus' Working Interest Fraction (Bscf)			Serinus' Net Entitlement Gas (Bscf)		
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible
Sabria	10.24	24.17	38.81	4.61	10.88	17.46	4.23	9.92	15.81
Chouech Es Saida	0.03	0.05	0.06	0.03	0.05	0.06	0.03	0.04	0.05
Total	**10.27**	**24.22**	**38.87**	**4.64**	**10.93**	**17.53**	**4.26**	**9.96**	**15.86**

Notes:

1. Gross Reserves are 100% of the volumes estimated to be commercially recoverable.
2. Serinus' Working Interest Fraction of the gross Reserves is inclusive of royalty.
3. Net Entitlement Reserves are Serinus' net economic entitlement under the Concession Agreement that governs the asset and are equal to Serinus' working interest fraction of the gross Reserves less royalty.
4. Serinus' working interest is 45% in Sabria and 100% in Chouech Es Saida.
5. Gas Reserves are quoted as sales volumes, net of fuel and flare.
6. Oil reserves include both export volumes and domestic market obligation volumes.
7. Totals may not exactly equal the sum of individual entries due to rounding.

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

(a) Sabria

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
7.5	43.86	94.73	143.05
10.0	39.20	82.36	123.47
12.5	35.21	72.42	107.99

(b) Chouech Es Saida

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
7.5	- 9.29	- 4.62	0.65
10.0	- 8.93	- 3.35	1.78
12.5	- 8.59	- 2.31	2.57

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.
3. The negative NPVs and the increase in NPV with discount rate for Chouech Es Saida are due to abandonment costs.

Discussion

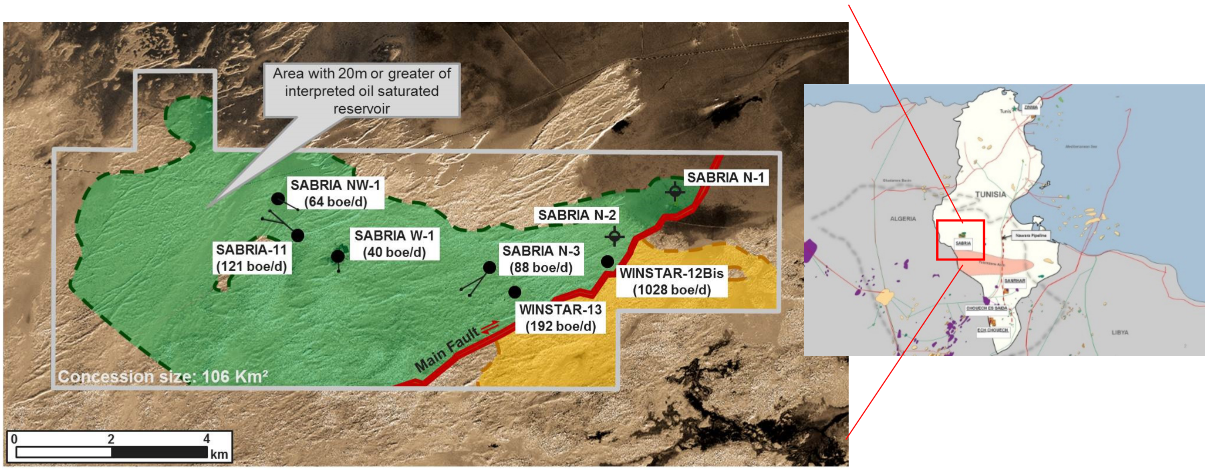
1 Background

1.1 Sabria

The Sabria Concession is located in the Chotts Basin in central western Tunisia (Figure 1). Serinus holds a working interest of 45%. The Concession Agreement runs until November 2028, when a 15-year extension is expected to be granted.

The Sabria Field was discovered in 1979 by exploration well SAB-N1. Well SAB-N2 was drilled in 1980/81, followed by SAB-N3 in 1984, and WSAB-1 in 1981/82. These wells tested oil in the Ordovician Hamra and El Atchane reservoirs, which are composed of tight sandstones, at a depth of approximately -3,750 m TVDss.

Figure 1: Sabria Field and Well Locations



Source: Serinus

Production commenced in 1998 from Well W-SAB-1H, a horizontal side-track of the original wellbore, completed near the top of the Hamra formation. Additional seismic surveys lead to the drilling of SAB-NW1, another horizontal well, which was put on production in 1999.

To date a total of 10 wells have been drilled on structure. Currently, four of the wells are producing (SAB-11, SAB-NW1H, WIN-12bis, and WIN-13) and two are shut-in. The most recent 3D seismic survey covering the field area was acquired in 2003.

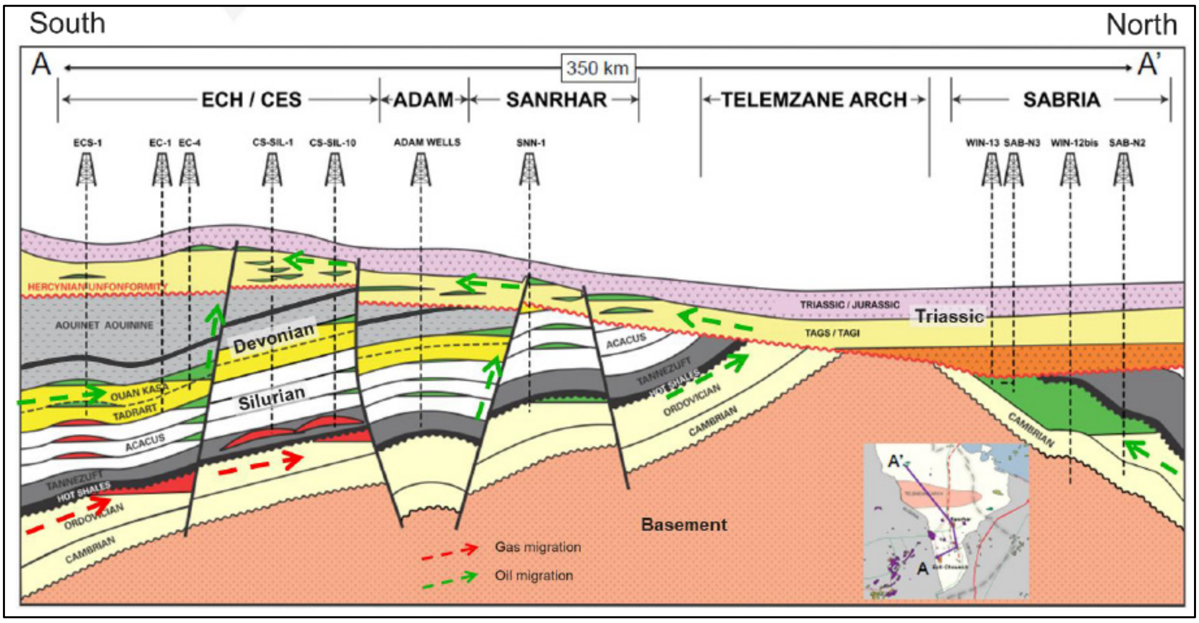
The oil is exported from the field via trucking to a transfer terminal on the local pipeline network at Oumchia, from where it is transported via pipeline to La Skhira on the Mediterranean coast.

Associated gas is recovered at the field where it is compressed to 1,440 psi pressure. Gas volumes are transported and sold to STEG, the Tunisian State Electricity and Gas Company. Condensate is recovered from the associated gas via a chilling unit and mixed with the crude oil stream for sales.

The predominant reservoir lithologies are fine to medium grained sandstone and quartzite. Core data indicates matrix porosity ranges from 8% to 12% and matrix permeability between 0.1 mD and 2 mD.

The trap at the Sabria Field is stratigraphic, with reservoir horizons sub-cropping the Hercynian Unconformity (Figure 2).

Figure 2: South-North Cross-Section



Source: Serinus

A summary of the rock and reservoir properties for Sabria is given in Table 3.

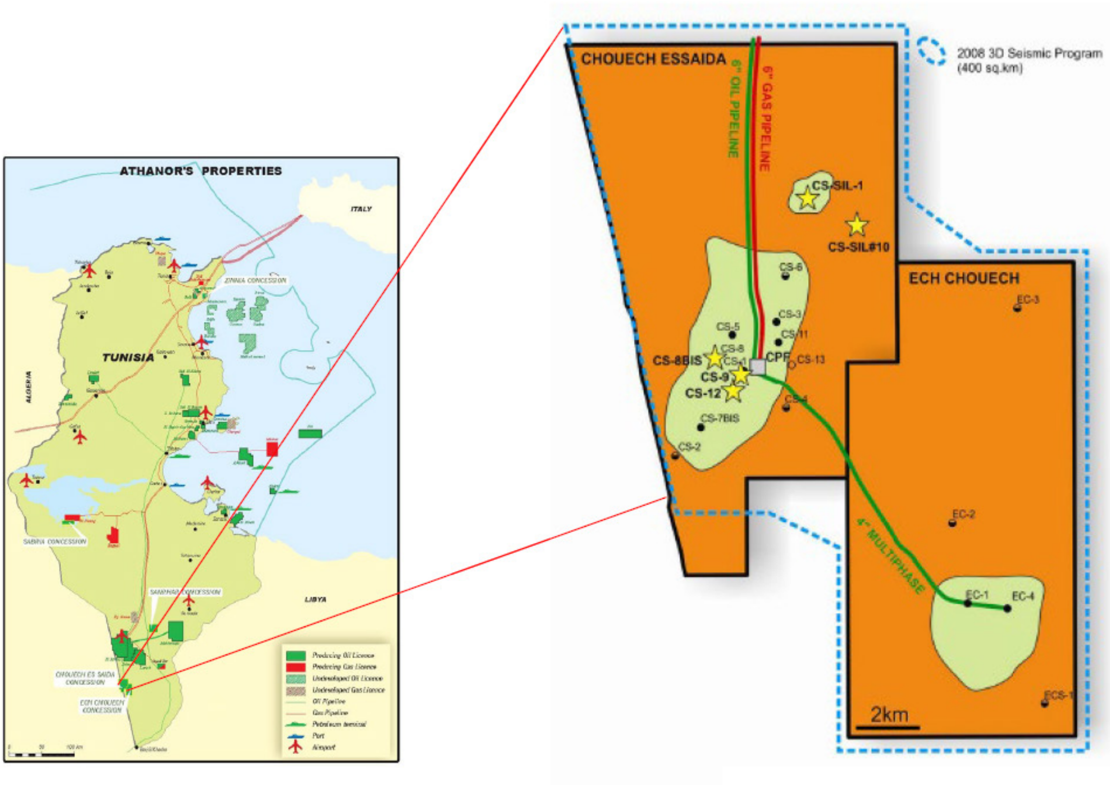
Table 3: Reservoir (Hamra and El Atchane) and Fluid Properties, Sabria Field

Reservoir Parameters		Fluid Parameters	
License Area	25,698 acres	Oil Gravity	42 ºAPI
Depth	3,730-3,739 m	Oil Viscosity	0.2 cP
Initial Reservoir Pressure	8,833 psia	Oil Formation Factor	2.6 rb/stb
Reservoir Temperature	228 ºF	Bubble Point Pressure	5,705 psia
Average Porosity	10%	Initial Solution GOR	2,780 scf/stb
Water Saturation	55%	Gas Gravity (Air=1)Gas Volume Factor	0.8
Average Gross Pay	38 m	Gas Compressibility Factor "Z"	0.95
Average Net to Gross	90%	Gas Formation Volume Factor	0.00296 rcf/scf

1.2 Chouech Es Saida

The Chouech Es Saida Concession is located in the Ghadames Basin in southern Tunisia (Figure 3). Serinus holds a working interest of 100%. The Concession Agreement runs until December 2027, when a 15 year extension is expected to be granted.

Figure 3: Chouech Es Saida and Ech Chouech Field and Well Locations



Source: Serinus

Seven wells were drilled on the Chouech Es Saida Field between 1971 and 1992. Production from one well (CS-1) began in 1977. Two other wells (CS-3bis and CS-7bis) were put on stream in 1992. Further drilling took place from 2006, when oil production was significantly increased. 15 wells have been drilled on the structure, of which only one was still on production by mid-2020 (CS-1). An ESP was installed on CS-3 and CS-7 and these wells restarted in December 2020, so three wells were producing at the end of 2020. In 2021, the ESP in CS-8 was restarted and production from this well re-commenced in September 2021.

Oil is transported to a sales point at El Borma by a six inch, 80 km pipeline that is owned by Serinus. Sales gas is exported via a six inch, 78 km pipeline from the field to El Borma, where it ties into a 16" pipeline for gas sales to STEG (Figure 3). The gas delivery system includes two field compressors with a capacity of 3 MMscfd each.

Fluvial reservoirs of the Late Triassic TAGS (Trias Argilo Gréseux Superieur) and Mid Triassic TAGI (Trias Argilo Gréseux Inferieur) are the target horizons. They are referred to from youngest to oldest as Reservoirs A, B, C, D, F, and G. No hydrocarbons were found at the level of Reservoir E, but the other reservoir horizons contain oil. Reservoirs of the Lower Acacus A (Silurian) and Tannezuft 1 and Tannezuft 2 (Silurian) Formations contain gas condensate, and have not yet been developed. The shallowest reservoirs are found at a depth of approximately -2,000 m TVDss and the deepest reservoir at -4,063 m TVDss.

The reservoir sandstones of the TAGI Formation display average log porosities of around 20% and average water saturations of approximately 26%. The Silurian reservoir display average porosities between 11 and 15%, and average water saturations of 50% to 55%.

The trap at the Chouech Es Saida Field is a NW-SE trending monocline.

A summary of the rock and reservoir properties for Chouech Es Saida is given in Table 4.

Table 4: Reservoir (TAGS/TAGI) and Fluid Properties, Chouech Es Saida Field

Properties	Value
Field Area	52,386 acres
Depth	2,000 m ss
Initial Reservoir Pressure	3,655 psia
Reservoir Temperature	160°F
Average Porosity	23%
Average Water Saturation	31%
Oil Gravity	42ºAPI
Oil Viscosity	0.26 cP
Oil Formation Factor	1.6 rb/stb
Bubble Point Pressure	3,655 psia
Initial Solution GOR	1,572 scf/stb
Gas Gravity (Air=1)Gas Volume Factor	0.74
Gas Compressibility Factor “Z”	0.78
Gas Formation Volume Factor	0.004 rcf/scf

2 Geology

Technical data and supporting documentation were provided to GaffneyCline in the form of presentations, and an IHS Kingdom project for the Sabria Field to review volume estimates made by Serinus.

2.1 Regional Geology

The Sabria Field is located in the Chotts Basin, which is separated from the Ghadames Basin to the south by the Touggourt-Talemzane-PGA-Bou Namcha (TTPB) Uplift. The Ech Chouech and Chouech Es Saida Fields are located in the Ghadames Basin. Both basins form part of the North African Margin, an area of complex and polyphasic geological evolution which can be summarised in two main phases: 1) Pre-Hercynian Phase, and 2) Post-Hercynian Phase.

Extension due to the reactivation of Pan-African fault systems during the Cambrian resulted in the formation of the “Early Ghadames Basin”, an intra-cratonic sag basin. Extension was followed by local transpressional and transtensional reactivation of the same fault system. The Lower Paleozoic section comprises up to five depositional sequences. Early Ordovician transgressive deposits consist of bioturbated fine-grained sandstones and silty shales, as well as the black silty and glauconitic marine shale of the El Gassi Formation. Shallow marine (shoreface) clastic sediments of the El Atchane Formation are fine- to medium-grained, bioturbated, shaly glauconitic sandstones. Progradation continues with deposition of quartzose sandstones of the Hamra Formation which are overlain by transgressive marine shales of the Azel Formation. Early and Middle Ordovician strata were truncated by the Taconian Unconformity which is overlain by Late Silurian – Early Devonian transgressive shales (Hot Shale and Fegaguira Shale). The Silurian Acacus Formation, which is absent in the Chotts Basin but preserved in the Ghadames Basin, consists of mudstone and sandstone deposited in marine to marginal marine environments.

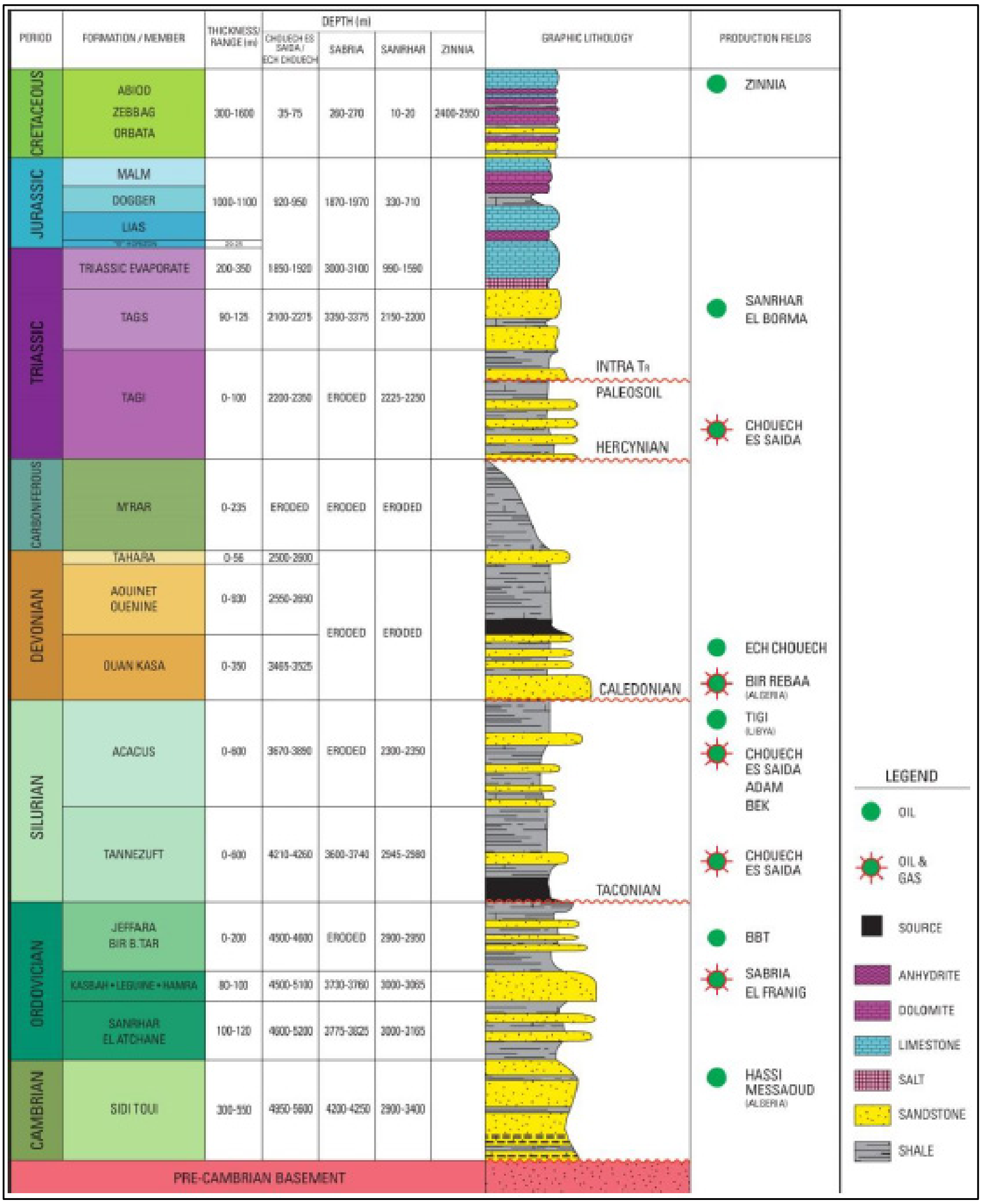
The Carboniferous to Permian is characterised by the Hercynian Orogeny, resulting in regional deformation, uplift, and consequently erosion of the Devonian, Carboniferous, Permian, and part of the Silurian deposits in the Chotts Basin. Development of the East-West trending TTPB structural high, where Triassic volcanics overly Cambrian basement, took place during the Late Hercynian phase.

Triassic volcanics, clastic continental deposits (Triassic TAGI Sandstones), and / or thick sequences of evaporites and carbonates unconformably overlie Pre-Hercynian deposits. Extension during the Triassic – Liassic linked to the Post-Hercynian break-up of Pangaea, rifting of the Neotethys and opening of the Central Atlantic Ocean is characterised by deposition of syn-rift successions. Regional subsidence continued until the Early Cretaceous and resulted in the formation of a Mesozoic extensional sag basin overlying the “Early Ghadames Basin”. Deposits of the time include thick sequences of salt, anhydrite, and carbonate.

During the Aptian, regional tectonics resulted in compression and reactivation of pre-existing fault trends. The regional Austrian Unconformity truncates and separates Neocomian to Barremian clastics from transgressive dolomites and claystone (Aptian – Albian). The Austrian event was followed by a phase of relative tectonic quiescence with the Pyrenean Orogeny only causing localised effects in southern Tunisia.

Convergence movement between Africa and Europe during the Late Eocene caused inversion of the North African passive margin, development of the Atlas fold belt and onset of foreland compression in the area of the Chotts Basin. This was followed by compression during the Serravalian to Tortonian related to the Neogene Alpine Phase. Overall stratigraphy is shown in Figure 4.

Figure 4: Regional Stratigraphy (Pre-Cambrian to Cretaceous)



Source: Serinus Database

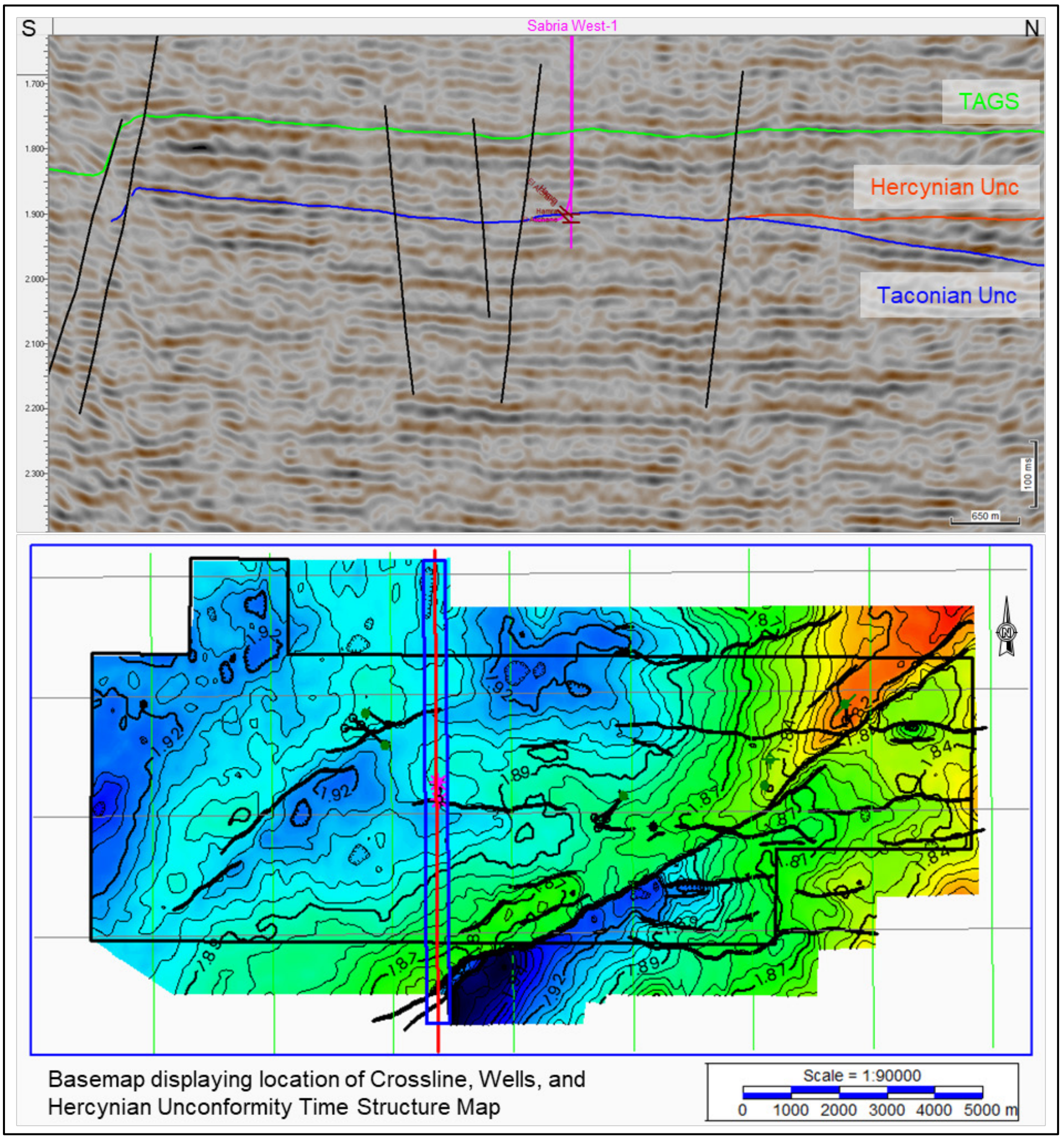
The sources of hydrocarbon within this region are at several levels ranging in age from Ordovician to Carboniferous. The Silurian Tanezzuft black shale is an excellent source rock which has been proven in the area.

The traps in the Ghadames Basin are structural, stratigraphic and combination. They are associated with anticlines, normal faulting, local inversion, and compaction features. Stratigraphic traps are up-dip shale-outs, and subcrops. Seals are provided by fine-grained rocks of various ages.

2.2 Seismic Data

The Sabria Concession is covered by a seismic survey, acquired in 2003 and with an areal extent of approximately 170 km^2. GaffneyCline reviewed the provided seismic interpretation and considered it reasonable for the purpose of volumetric estimation. Overall quality of the seismic data is fair at best. The Hercynian and Taconian (equals Top Hamra) Unconformities are reasonably well imaged on the seismic data (Figure 5). Some faults are well imaged on the seismic data set as vertically consistent reflector terminations. However, faulting could be more prevalent than currently mapped.

Figure 5: S-N Seismic Line (Crossline 337), Sabria Concession



Source: GaffneyCline from Serinus Database (IHS Kingdom project)

2.3 STOIIP and GIIP

2.3.1 Sabria

At year-end 2020, gross rock volumes (GRV) were independently calculated by GaffneyCline for the Sabria Field following a map based approach for each reservoir zone, between the top and base reservoir surfaces and above the fluid contact at -3,760 m TVDss. A variance of ± 30% was applied to allow for uncertainty in structural envelope and contact depth.

Serinus' estimates of reservoir parameters (net-to-gross 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 to estimate STOIIP for each of the reservoir intervals. Results are shown in Table 5. The estimates have not been updated as no new data are available.

Figure 6 shows the top structure depth maps, including concession boundaries, well locations, and contact depth. Figure 6 shows the Main Field area to the north of the NW-SE trending fault and the Extension area to the south (Table 5 and Table 6).

2.3.2 Chouech Es Saida

GaffneyCline has not made any independent estimates of STOIIP or GIIP for the Chouech Es Saida Field. Serinus quotes a total STOIIP range of 22 to 37 MMBbl for the Triassic reservoirs, and a total GIIP ranging from 6 to 15 Bscf for the Silurian reservoirs (RPS 2020[1]).

Table 5: Sabria Field STOIIP and GIIP (Main Field)

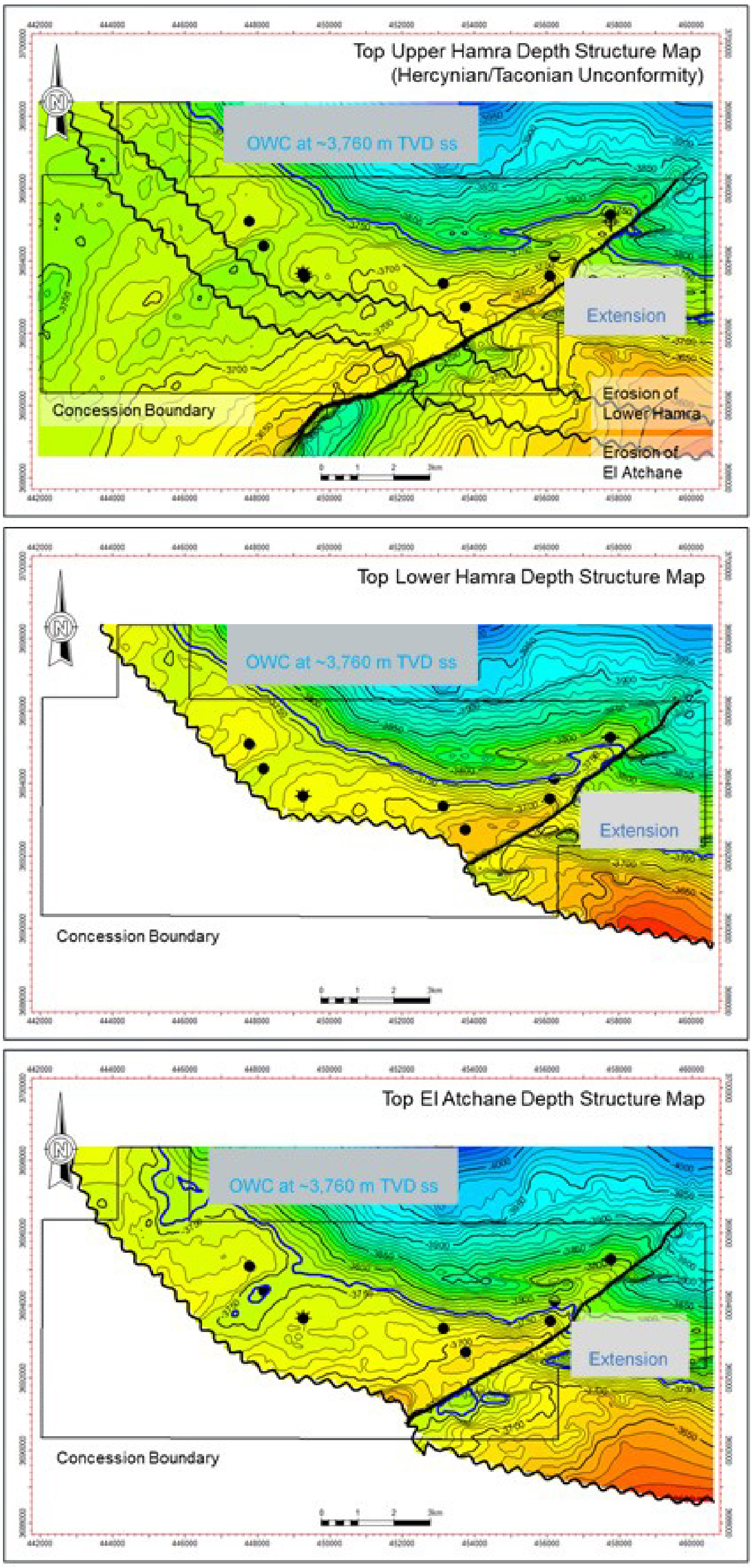
Reservoir	STOIIP (MMBbl)			Solution GIIP (Bscf)		
	Low	Best	High	Low	Best	High
Upper Hamra	30	46	68	83	127	191
Lower Hamra	44	67	100	120	185	280
El Atchane	126	192	288	349	533	803
TOTAL	**200**	**305**	**457**	**553**	**845**	**1,273**

Table 6: Sabria Field STOIIP (Extension Area)

Reservoir	STOIIP (MMBbl)			
	Low	Best	High	High/Low
Upper Hamra	22	34	51	2.3
Lower Hamra	16	24	37	2.3
EL Atchane	21	32	48	2.3
Total	**59**	**90**	**135**	**2.3**

[1] RPS Group (2020). Reserves & Contingent Resources Evaluation as of December 31, 2019

Figure 6: Top Upper, Lower Hamra and Top El Atchane Depth Structure Map



Source: GaffneyCline (from Serinus Energy database)

3 Reservoir Engineering

3.1 Sabria Field

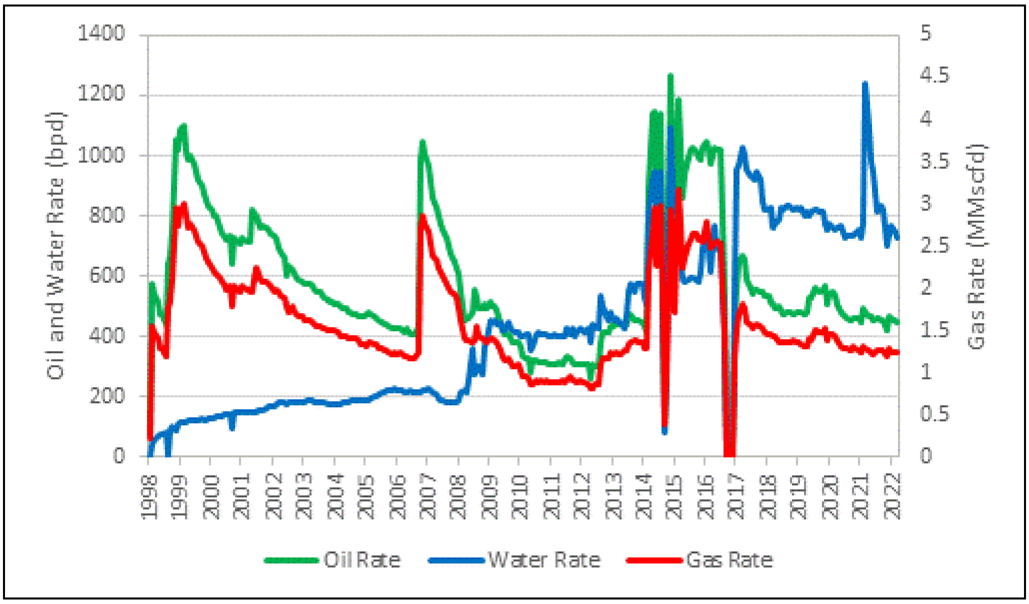
3.1.1 Production History

Production began in October 1998 from well W-SAB-1H. A second horizontal well, SAB-NW1, was put on production in May 1999. This was followed by SAB-N3H in 2009, WIN-12bis (vertical) in July 2014, WIN-13 (vertical) in March 2015 and SAB-11 (bi-lateral open hole) in July 2017. The field was shut in from May to September 2017 due to social unrest.

Production is currently from four wells: SAB-11, SAB-NW1, WIN-12bis and WIN-13. The average oil rate, water rate, gas rate and water cut were 456 bopd, 832 bwpd, 1.2 MMscfd and 60% respectively in 2022. The total oil and gas produced to the end of 2022 were 4.8 MMBbl and 13.1 Bcf respectively. The increase in water production in Sabria was caused by the net effect on WIN-12 production of temporarily increasing choke size to check behaviour with increased total liquid offtake rate.

The oil, water and gas production history are shown in Figure 7.

Figure 7: Sabria Field Oil, Water and Gas Production



Source: GaffneyCline from Serinus data

Table 7 shows the average production of each well in 2022, cumulative production at the end of December 2022 and the current well status.

Table 7: Sabria Field Well Status, Production Rate and Cumulative Oil Produced as at 31st December 2022

Well	Average 2022 Oil Production Rate (bpd)	Cumulative Produced Oil (MMBbl)	Average 2022 Gas Production Rate (MMscfd)	Cumulative Produced Gas (Bscf)	Well Status
SAB-N1	-	-	-	-	Suspended Oil Well
SAB-N2	-	-	-	-	Suspended Appraisal well
SAB-11	88	0.80	0.3	2.25	Oil and Gas Producer
SAB-N3H	-	0.02	-	0.05	Suspended
SAB-W1	-	0.90	-	2.54	Suspended
SAB-NW1	56	1.77	0.2	5.04	Oil and Gas Producer
WIN-12bis	225	0.95	0.6	2.35	Oil and Gas Producer
WIN-13	87	0.33	0.2	0.91	Oil and Gas Producer
Total	**456**	**4.77**	**1.2**	**13.14**	

3.1.2 Future Development

3.1.2.1 Future Development: ESP Installation

A technical study carried out for Serinus by a third party consultant (Sabria Artificial Lift Selection Project, September 2020) shows the potential benefits of installing artificial lift in the Sabria field. This was based on a thorough analysis of the current and historical production data and use of calibrated material balance models. Based on the results of the study, Serinus plans to install Electrical Submersible Pumps (ESP) in two producing wells (WIN-12 and SAB-NW1) and one suspended wells (SAB-W1).

SAB-N3N in Sabria is a candidate for bringing back into production using artificial lift and had been included in last year's production forecasts based on the Sabria Artificial Lift Selection Project, September 2020. Optimising future production from the well requires some of the water-producing sections of the horizontal legs to be shut off. This in turn needs a flow survey to identify the areas of the well that produce water and those that produce oil. Serinus' partner in the field did not approve the flow survey and by implication the artificial lift programme. The well is still a candidate for future production but is not included in the base case production forecast at present.

Table 8 and Table 9 show the planned timing of ESP production start-up, estimated oil and gas rates and ultimate recovery by well following the planned ESP installations. Dates are slightly revised since year-end 2021 and estimated rates and recoveries have also been updated.

Table 8: Sabria Field; Estimated Oil Benefit of ESPs

Well	Average 2022 Oil Production Rate (bpd)	Forecast Best Case EUR (MMBbl)	ESP Installation Date	Initial Post-ESP Oil Rate (bpd)	Forecast Best Case EUR (MMBbl)
SAB-11	88	1.28	No ESP	88	1.28
SAB-N3H	-	0.02	No ESP	0	0.02
SAB-W1	-	0.90	Feb-23	400	2.07
SAB-NW1	56	2.04	Feb-26	57	2.47
WIN-12bis	225	1.97	Nov-23	1,400	4.67
WIN-13	87	0.78	No ESP	87	0.78
Total	456	6.99		2,032	11.29

Note:

1. EUR shown here is the best estimate of ultimate technically recoverable volume from the well (end of concession and assuming a 15-year extension to 2043) no economic cut-off has been applied.

Table 9: Sabria Field; Estimated Gas Benefit of ESPs

Well	Average 2022 Gas Production Rate (MMscfd)	Forecast Best Case EUR (Bcf)	ESP Installation Date	Initial Post-ESP Gas Rate (MMscfd)	Forecast Best Case EUR (Bcf)
SAB-11	0.26	3.71	No ESP	0.26	3.71
SAB-N3H	-	0.05	No ESP	0	0.05
SAB-W1	-	2.54	Feb-23	1.12	5.81
SAB-NW1	0.20	5.78	Feb-26	0.18	6.98
WIN-12bis	0.57	4.80	Nov-23	3.36	11.26
WIN-13	0.22	1.95	No ESP	0.22	1.95
Total	1.25	18.83		5.14	29.77

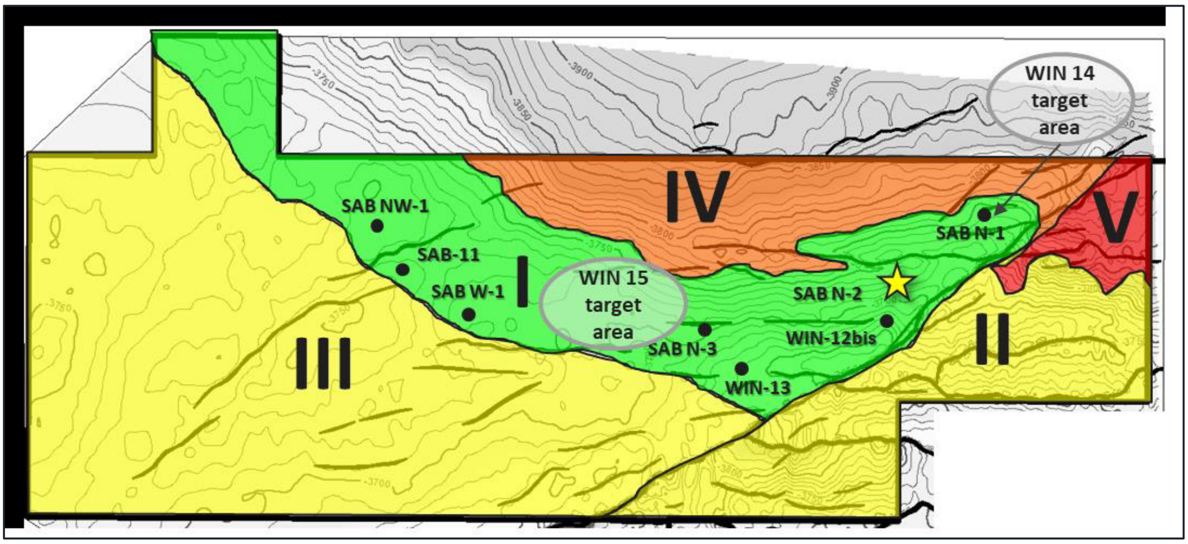
Note:

1. EUR shown here is the best estimate of ultimate technically recoverable volume from the well (end of concession and assuming a 15-year extension to 2043); no economic cut-off has been applied.

3.1.2.2 Future Development: New Wells

Serinus plans a workover of the SAB-N2 well in 2023 (first production expected in April) and two infill wells (WIN-14 and WIN-15) within the area proven by the existing wells (Figure 8). The infill wells are planned for 2025. The SAB-N2 workover will include an acid injection program and drill stem test. During the original drilling, the well experienced drilling problems and there were mechanical failures during the well test, so it is possible there was damage to the wellbore due to prolonged exposure to heavy mud.

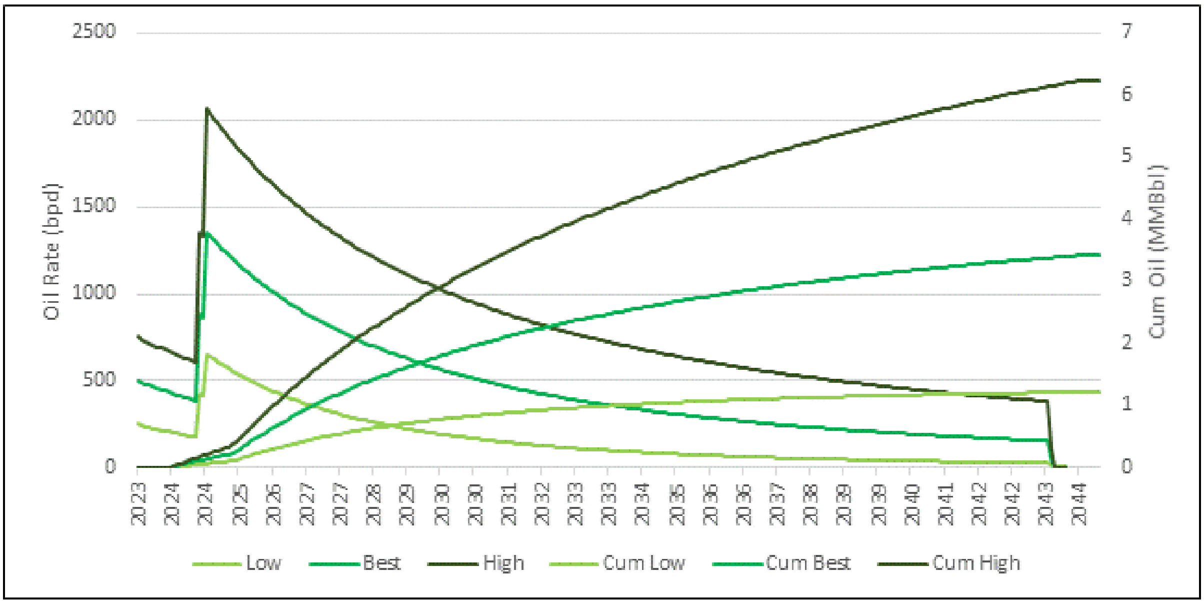
Figure 8: Sabria Field Workover and Infill Well Target Locations



Source: Serinus

SAB-N1 was originally tested in 1979 over the interval 3,766-3,775 m, with an oil rate of 515 bpd, gas rate of 1.8 MMscfd and a watercut of 20% on a 16/64" choke. WIN-14 will be a side-tracked or re-drilled from the SAB-N1 well followed by an acid wash. The Low, Best and High total oil production profiles for SAB-N2, WIN-14 and WIN-15 developed by Serinus were considered reasonable by GaffneyCline and are shown in Figure 9.

Figure 9: Sabria Field Workover and Infill Well Oil Forecast Production



3.1.3 Production Forecast, Ultimate Recovery and Reserves

GaffneyCline used decline curve analysis (DCA) to forecast the production rate and volumes for the currently producing wells in the Sabria field. The DCA was done on a well by well basis and summed for the total field production profile. The methodology to produce the Low, Best and High profiles was as follows:

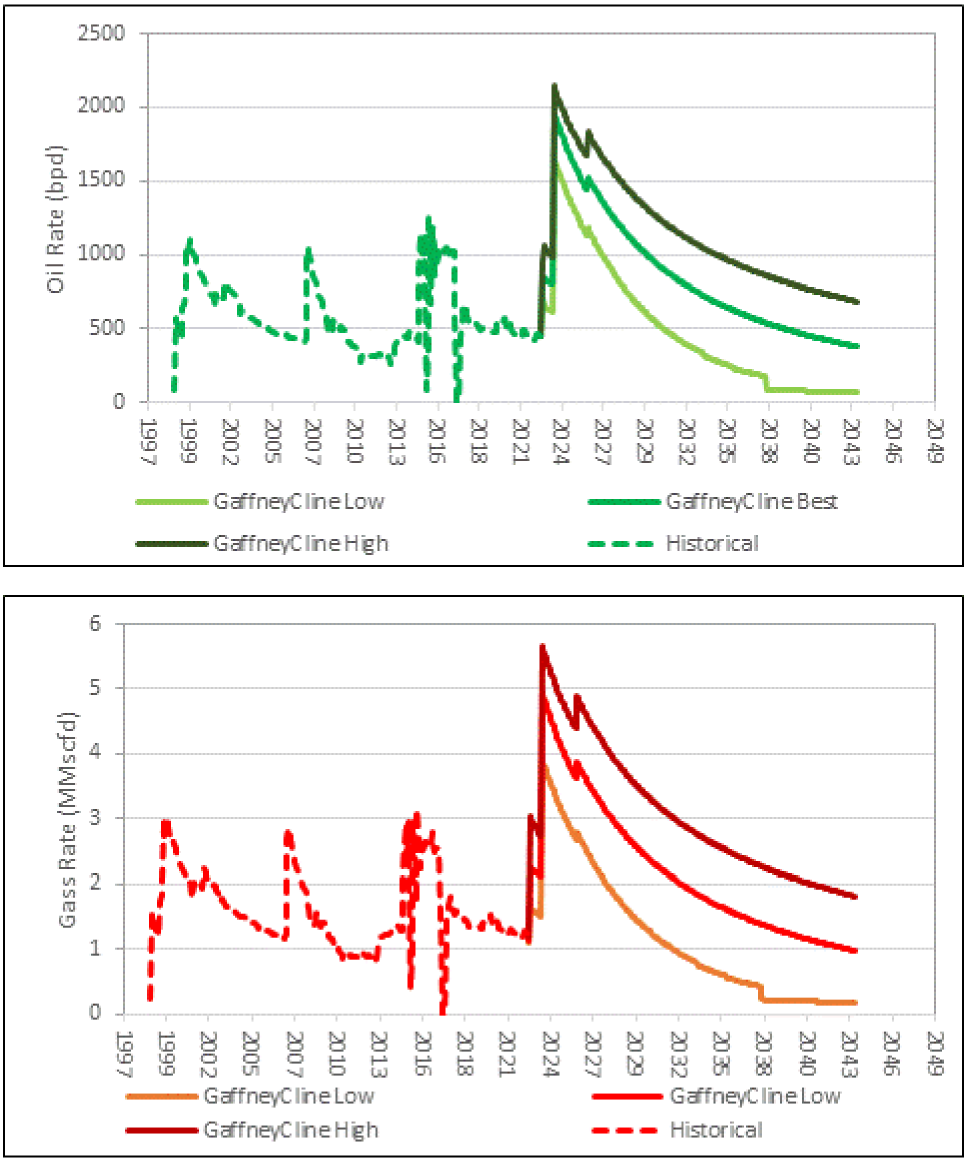
- Low Case: Oil Cut vs Cumulative Oil (Exponential Decline):
  - Oil rate is calculated from the current constant liquid rate and oil cut forecast.
- Best Case: Oil Rate vs Cumulative Oil (Hyperbolic Decline):
  - Oil rate is calculated from oil rate vs cumulative oil decline forecast.
- High Case: Water Oil Ratio (WOR+1) vs Cumulative Oil (Harmonic Decline):
  - Oil rate is calculated from the current constant liquid rate and WOR Forecast.

Figure 10 shows the historical production and the Low, Best and High oil and gas production forecasts for Sabria, which are the sum of the NFA profiles and the profiles for all planned well activities. The GOR from historical data for the Low, Best and High cases respectively was used to determine the gas rates for the existing wells and the N2 workover gas production forecasts. GaffneyCline has accepted Serinus' gas production forecasts for WIN14 and WIN15.

The resulting estimates of the technically recoverable oil and gas volumes by the end of the Concession in December 2043, and the remaining technically recoverable oil and gas volumes over the forecast period from 2023 through to end 2043 are shown in Table 10 and Table 11.

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

Figure 10: Sabria Field Oil and Gas History and Forecast Production



Notes:

1. No economic cut off has been applied to the profiles shown here.
2. The gas rates are wellhead rates and have not been adjusted for shrinkage, fuel and flare.
3. The profiles include ESP installations, the SAB-N2 workover and the WIN-14 and WIN-15 infill wells.

Table 10: Technically Recoverable Oil Resources, Sabria Field as at 31st December 2022

	Ultimate Technically Recoverable Oil (MMBbl)			Remaining Technically Recoverable Oil (MMBbl)		
	Low	Best	High	Low	Best	High
Developed	5.66	6.99	7.61	0.89	2.22	2.84
Undeveloped ESP	2.81	4.29	5.94	2.81	4.30	5.94
Undeveloped Workovers/ Infill Wells	1.22	3.42	6.24	1.22	3.42	6.24
Total	**9.69**	**14.71**	**19.80**	**4.92**	**9.94**	**15.03**

Notes:

1. Historical oil production from the field by end-2022 is around 4.8 MMBbl.
2. The volumes represent gross numbers (100% WI).
3. The volumes shown here are those estimated to be technically recoverable before the end of the Concession Agreement at end 2043. No economic cut off has been applied to the volumes.
4. Remaining volumes are as of 31st December 2022.
5. Numbers may not add up due to rounding.

Table 11: Technically Recoverable Gas Resources, Sabria Field as at 31st December 2022

	Ultimate Technically Recoverable Gas (Bscf)			Remaining Technically Recoverable Gas (Bscf)		
	Low	Best	High	Low	Best	High
Developed	18.76	19.38	21.75	5.63	6.24	8.62
Undeveloped ESP	3.24	10.39	14.76	3.24	10.39	14.76
Undeveloped Workovers/ Infill Wells	3.42	9.58	17.47	3.42	9.58	17.47
Total	25.42	39.34	53.98	12.28	26.21	40.84

Notes:

1. Historical gas production in the field by end-2022 is around 13.1 Bcf.
2. The volumes represent gross numbers (100% WI).
3. The volumes shown here are those estimated to be technically recoverable before the end of the Concession Agreement at end 2043. No economic cut off has been applied to the volumes.
4. Remaining volumes are as of 31st December 2022.
5. The gas volumes are wellhead volumes and have not been adjusted for losses due to shrinkage, fuel and flare.
6. Numbers may not add up due to rounding.

3.1.4 Costs

Total CAPEX for the future planned activities is estimated by Serinus at US$28.67 MM, broken down as follows:

- US$5.44 MM for the SAB-NW1, SAB-W1, and WIN-12 Artificial Lift;
- US$1.90 MM for the N-2 well re-entry;
- US$17.32 MM for the two new wells, SAB-14 and SAB-15;
- US$3.21 MM for CPF and pumping station upgrade; and
- US$0.14 MM annually for maintenance.

Future OPEX has been estimated as follows:

- Fixed OPEX: US$250,000 per month; and
- Variable OPEX: US$3.50/Bbl oil and US$0.58/Mscf gas.

Abandonment cost has been estimated at US$8.19 MM (2022 real terms).

The above costs are the net remaining costs for wells and workovers and are significantly less than the costs presented at the end 2022. The main reason is due to long-lead items costs already incurred in 2022. The costs for the SAB-N3H artificial lift have been removed until partner approvement is attained. The costs have also been impacted by USD appreciation versus the Dinar over 2022 to present and costs have been further updated after a rig was contracted in 2022.

GaffneyCline has reviewed these cost estimates and accepts them as reasonable.

3.1.5 Contingent Resources

Contingent Resources are attributed to two further potential development wells (WIN-16 and WIN-17), as shown in Table 12. Well WIN-12 encountered a natural fracture network, which was evident on the logs and cores. The core analysis indicated significantly higher permeability than observed in offset wells. Serinus believes there may be similar fracture networks elsewhere in the field that could be the target of future wells and is currently carrying out studies to better understand this and define well locations.

Table 12: Contingent Resources, Sabria Field, as at 31st December 2022

Fluid	Gross Field			Net to Serinus (WI Basis)		
	1C	2C	3C	1C	2C	3C
Oil (MMBbl)	0.8	2.3	4.2	0.4	1.0	1.9
Gas (Bscf)	2.3	6.4	11.8	1.0	2.9	5.3

Notes:

1. Gross Field Contingent Resources are 100% of the volumes estimated to be recoverable from the project, in the event that it is developed.
2. Contingent Resources Net to Serinus in his table are Serinus' Working Interest fraction of the Gross Field Contingent Resources; they do not represent Serinus' net economic entitlement under the Concession Agreement that governs the asset, which would be lower due to deduction of royalty.
3. 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).
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.

3.2 Chouech Es Saida Field

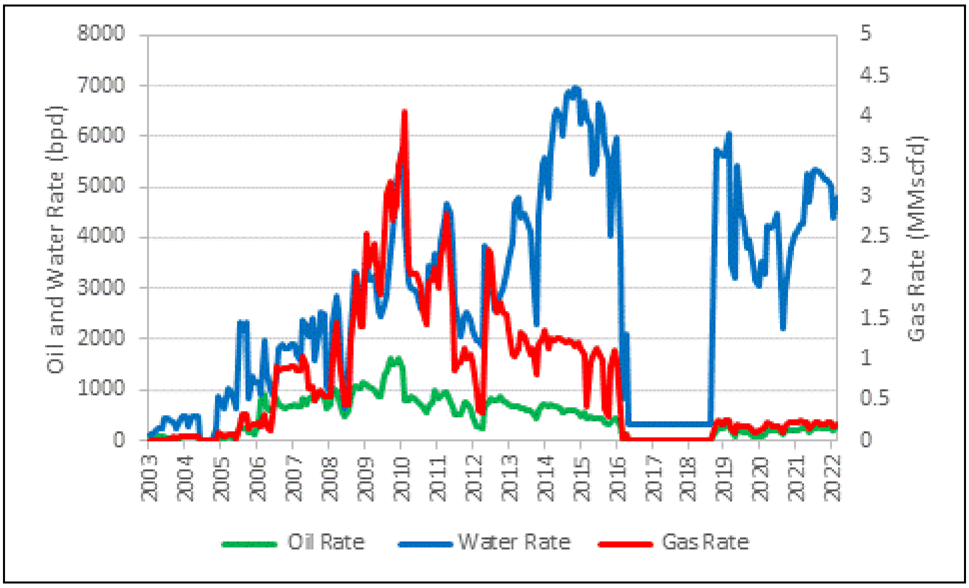
3.2.1 Production History

Production from one well (CS-1) began in 1977. Two other wells (CS-3bis and CS-7bis) were put on stream in 1992. Further drilling took place from 2006, when oil production was significantly increased. Production was shut-in in February 2017 due to social unrest in the area. The field resumed production in July 2019 through CS-1, CS-7 and CS-9, while CS-3 resumed production in August 2019. However, only CS-1 was still on production in mid-2020. An ESP was installed on CS-3 and CS-7 and these wells restarted in December 2020, while the ESP of CS-8 was restarted in September 2021 resulting in four wells on production at the end of 2022.

The average oil rate, water rate, gas rate and water cut were 239 bopd, 4,987bwpd, 0.2 MMscfd and 95% respectively in 2022.

The total oil and gas produced to the end of December 2022 was 3.1 MMBbl and 4.87 Bcf respectively. The oil, water and gas production history are shown in Figure 11.

Figure 11: Chouech Es Saida Field Oil, Water and Gas Production end 2022



Source: GaffneyCline from Serinus production data

Table 13 shows the average production of each well in 2022, cumulative production at the end of December 2022 and the current well status.

Table 13: Chouech Es Saida Field Well Status, Production Rate and Cumulative Oil Produced as at 31st December 2022

Well Name	Average 2022 Oil Production Rates (bpd)	Cumulative Produced Oil (MMBbl)	Average 2022 Gas Production Rate (MMscfd)	Cumulative Produced Gas (Bscf)	Well Status
CS-1	50	0.90	0.06	1.24	Oil Producer
CS-2	-	-	-	-	Abandoned Oil Producer
CS-3	93	0.46	0.09	2.12	Oil Producer
CS-4	-	-	-	-	Abandoned Oil Producer
CS-5	-	0.19	-	-	Gas Producer Shut in
CS-6	-	-	-	-	Abandoned Injector
CS-7	77	0.71	0.05	0.11	Oil Producer
CS-8/CS-8bis/CS-8ST	18	0.16	0.01	0.31	Oil Producer
CS-9	0	0.50	0.01	0.83	Oil Producer Shut in
CS-11	-	0.14	-	0.26	Suspended Oil Producer
CS-12	-	-	-	-	Suspended Oil Producer
CS-Sil-1	-	-	-	-	Suspended Gas/Condensate Producer
CS-Sil-10	-	-	-	-	Suspended Gas Producer
Total	**239**	**3.05**	**0.20**	**4.87**	

Note:

1. Historical production data only available for CS-1, CS-3, CS-5, CS-7, CS-8, CS-9 and CS-11.

3.2.2 Future Development

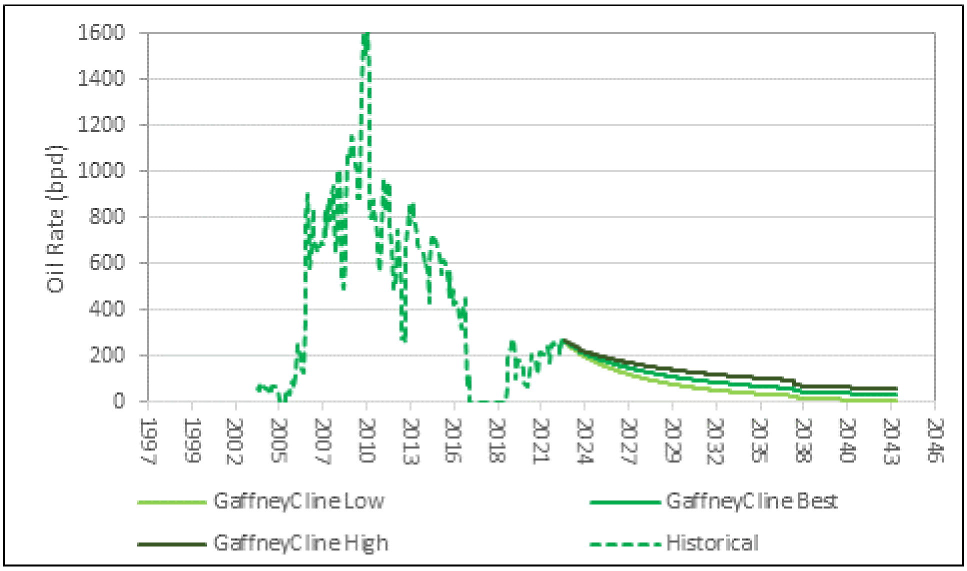
This includes replacement ESP's for producing wells every two years to sustain production.

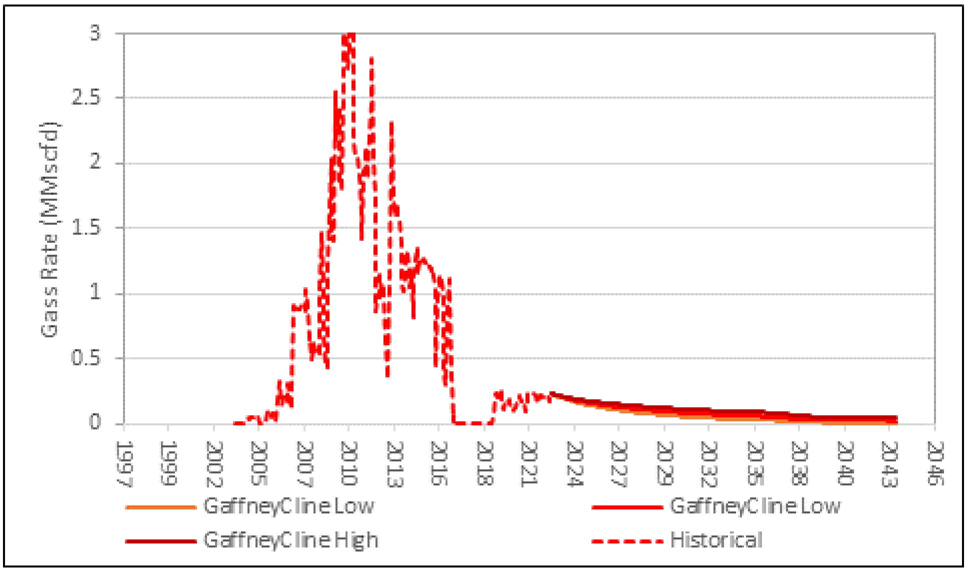
3.2.3 Production Forecast, Ultimate Recovery and Reserves

GaffneyCline used DCA to forecast the production rate and volumes for the Chouech Es Saida field. The DCA was done on a well by well basis and summed for the field production profile. An exponential, hyperbolic and harmonic decline were defined for the Low, Best and High cases respectively, as described in Section 3.1.3.

Figure 12 shows the historical production and the Low, Best and High oil and gas production forecasts for Chouech Es Saida. A constant GOR for each well was used based on production history to determine the gas rates in all cases.

Figure 12: Chouech Es Saida Field Oil and Gas History (CS-1, CS-3, CS-5, CS-7, CS-8, CS-9 and CS-11) and Forecast Production





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.

The resulting estimates of the technically recoverable oil volumes by the end of the Concession in December 2042, and the remaining technically recoverable oil volumes over the forecast period from 2022 through to end 2042 are shown in Table 14.

The gross oil and gas volumes and cost profiles for Chouech Es Saida are shown in Appendix III.

Table 14: Technically Recoverable Oil Resources, Chouech Es Saida Field as at 31st December 2022

Ultimate Technically Recoverable Oil (MMBbl)			Remaining Technically Recoverable Oil (MMBbl)		
Low	Best	High	Low	Best	High
3.57	3.77	3.97	0.51	0.72	0.91

Notes:

1. Historical oil production in the field by end-2022 is around 3.05 MMBbl.
2. The volumes represent gross numbers (100% WI).
3. The volumes shown here are those estimated to be technically recoverable before the end of the Concession Agreement at end 2042. No economic cut off has been applied to the volumes.
4. Remaining volumes are as of 31st December 2022.
5. Numbers may not add up due to rounding.

3.2.4 Costs

Total CAPEX for the future planned activities at Chouech Es Saida field are estimated by Serinus at US$0.50 MM related to the CS-1 and CS-3 workovers, back-up pump costs of US$0.98 MM, CS-1 water shut-off expenditure of US$ 0.22 MM and annual maintenance costs of US$ 0.20 MM.

Future OPEX has been estimated as follows:

- Fixed OPEX : US$180,000 per month; and
- Variable OPEX: US$7.10/Bbl oil.

Abandonment cost has been estimated at US$13.90 MM (2022 real terms).

GaffneyCline has reviewed these cost estimates and accepts them as reasonable.

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 each of Serinus' concessions in Tunisia. 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 each concession, and the various economic and commercial assumptions described herein.

GaffneyCline has not had access to the Tunisian 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.

Serinus Net Working Interest Cash Flows for each Reserves case for Sabria and Chouech Es Saida concessions are shown in Appendix IV.

4.1 Oil and Gas Prices

GaffneyCline's 1Q 2023 Brent Crude oil price scenario, shown in Table 15, has been used for the economic assessments conducted herein.

As advised by Serinus, crude oil and condensate liquids from the Sabria and Chouech Es Saida concessions are sold at a discount of US$0.35/Bbl to Brent. Gas prices are calculated as a function of the Brent crude oil price as described below.

*Sabria Gas Price (US$/mcf) = Brent Crude Price (US$/Bbl) * 0.125*

*Chouch Es Saida Gas Price (US$/Mcf) = Brent Crude Price (US$/Bbl) * 0.11*

Table 15: GaffneyCline Brent Crude Oil Price Scenario

Year	Oil Price (US$/Bbl)
2023	83.83
2024	78.99
2025	80.00
2026+	+2.00% Thereafter

For the cash flow calculations, costs have been escalated at 2.0% per annum from 2024.

4.2 Contract and Fiscal Terms

The relevant elements of the Tunisian fiscal regime for petroleum operations as they currently stand are summarised below and are assumed to remain constant for the period of audit.

4.2.1 Domestic Supply Obligation (DMO)

20% of all oil produced within the Sabria Concession is sold in the domestic market at a 10% discount to international prices. Serinus advised that the Chouch Es Saida concession does not have a domestic market obligation.

4.2.2 Royalty

Royalty is payable on pre-DMO revenues and generally ranges between 2% and 15%.

The royalty rate on oil production for the Sabria Concession is based on an R-Factor calculation (Table 16). The R-Factor is defined as a ratio of cumulative net revenue to total cumulative expenditure. Closing balances of cumulative net revenue (gross revenue less royalty and taxes) and cumulative expenditure for Sabria as at 31st December 2022 were advised by Serinus.

Table 16: Royalty Based on R-Factor for Sabria Concession

R Factor	Oil	Gas
	Royalty (%)	Royalty (%)
< 0.5	2.0	2.0
0.5 – 0.8	5.0	4.0
0.8 – 1.1	7.0	6.0
1.1 – 1.5	10.0	8.0
1.5 – 2.0	12.0	9.0
2.0 – 2.5	14.0	10.0
2.5 – 3.0	15.0	11.0
> 3.5	15.0	13.0

The royalty on oil and gas production from the Chouch Es Saida Concession is a flat 15% and not dependent on any R-Factor.

4.2.3 Corporate Income Tax (CIT)

The CIT rates for Sabria Concession are calculated based on the same R-Factors used to calculate Royalty, and are shown in Table 17. The CIT rate paid for the Chouch Es Saida Concession is a flat 35% and not dependent on R-Factor.

The capital depreciation method for CIT calculation is 30% annual straight line depreciation for Sabria and 10% annual straight line depreciation for Chouch Es Saida.

Table 17: CIT Based on R-Factor for Sabria Concession

Oil		Gas	
R Factor	CIT Rate (%)	R Factor	CIT Rate (%)
< 1.5	50.0	< 2.5	50.0
1.5 – 2.0	55.0	2.5 – 3.0	55.0
2.0 – 2.5	60.0	3.0 – 3.5	60.0
2.5 – 3.0	65.0	> 3.5	65.0
> 3.5	70.0	-	-

4.2.4 Export Tax Duty

An export tax of 1.5% is payable on the revenue (excluding Royalty) from oil sales in the international market for each Concession. However, this payment is considered as advance and can be claimed against CIT payment.

4.3 Results of Economic Analysis

Sabria economic limit was calculated to be at end of 2039 in the Low case (Proved Reserves). For the Mid and High cases, no economic limit was reached before expiry of the Concession in 2043.

The economic limit for the Chouech Es Saida Concession was found to occur at end 2024 in the Proved case, 2030 in the Proved plus Probable case and 2034 in the Proved plus Probable plus Possible case.

Resulting Reserves, both gross and net to Serinus, are reported in the Executive Summary in Table 1, and the corresponding NPVs in Table 2. Reserves net to Serinus are equal to Serinus' working interest fraction of the gross field Reserves less royalty.

4.4 Price Sensitivity Analysis

A sensitivity analysis was conducted by using forward price curves of Brent Crude Futures as on 1 Jan 2023. Economic Limit of the 1P case of Sabria was found to occur two years earlier leading to a 2% reduction in 1P reserves. There is no change to the 2P and 3P reserves under the Forward price curve scenario. NPV10 of 2P case was found to be 18% lower compared to the base case price scenario under the Forward curve scenario.

For Chouch Es Saida Concession, there was no change to the economic limit of the 1P case while 2P and 3P cases had their economic limit advanced to 2024(64% reduction in reserves) and 2029(31% reduction in reserves) respectively under the Forward price curve scenario.

Appendix I
Glossary

GLOSSARY

Standard Oil Industry Terms and Abbreviations

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

EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FPSO	Floating production, storage and offloading vessel
FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GTL	Gas to liquids
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)

Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Post stack depth migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved undeveloped
PVT	Pressure volume temperature
P10	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RUB	Russian Rouble
R_w	Resistivity of water

SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water saturation
t	Tonnes
TD	Total depth
te	Tonnes equivalent
THP	Tubing head pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical committee meeting
TOC	Total organic carbon
TOP	Take or pay
tpd	Tonnes per day
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)

Appendix II
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

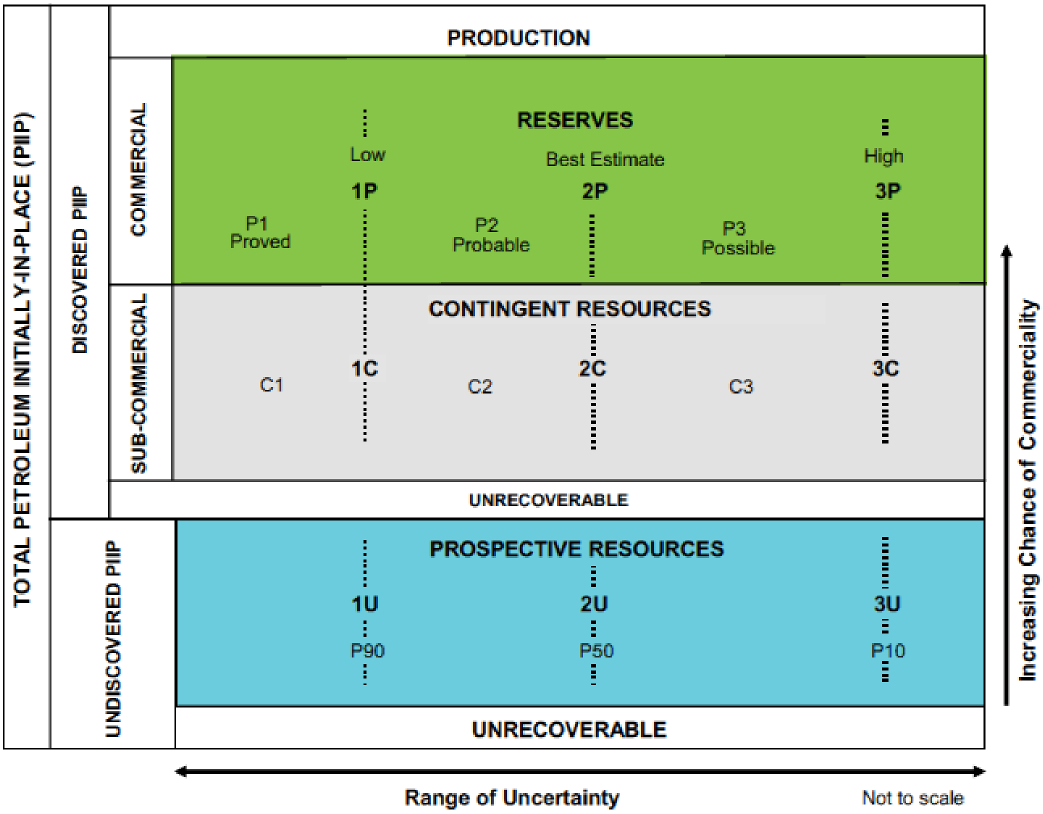
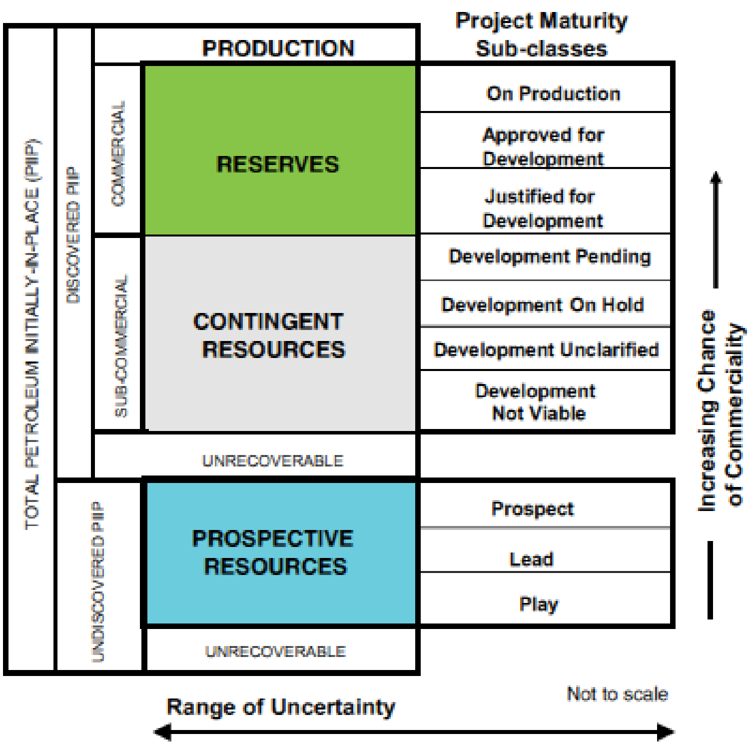


Figure 2.1—Sub-classes based on project maturity



Appendix III
Gross Technical Oil and Gas Production Volumes and Cost Profiles

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

Gross Production and Cost Profiles - Low Case				
Year	Oil (MMBbl)	Gas (Bscf)	CAPEX (US$ MM)	OPEX (US$ MM)
2023	0.35	0.78	11.84	4.69
2024	0.67	1.54	38.13	6.24
2025	0.65	1.53	13.18	6.18
2026	0.55	1.28	1.33	5.69
2027	0.46	1.04	0.32	5.21
2028	0.38	0.85	0.30	4.83
2029	0.32	0.69	-	4.52
2030	0.27	0.57	-	4.27
2031	0.23	0.47	-	4.07
2032	0.19	0.39	-	3.90
2033	0.16	0.31	-	3.76
2034	0.14	0.25	-	3.62
2035	0.12	0.20	-	3.53
2036	0.10	0.16	-	3.44
2037	0.09	0.12	-	3.37
2038	0.05	0.03	-	3.19
2039	0.05	0.02	-	3.17
2040	0.04	0.02	-	3.16
2041	0.04	0.01	-	3.14
2042	0.04	0.00	-	3.13
2043	0.03	-	-	3.11
Total	**4.92**	**10.26**	**65.11**	**86.21**

Notes:

1. The volumes and costs represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2043.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Table AIII.2: Sabria Gross Oil and Gas Production Volumes and Cost Profiles - Best Case

Gross Production and Cost Profiles - Best Case				
Year	Oil	Gas	CAPEX	OPEX
	(MMBbl)	(Bscf)	(US$ MM)	(US$ MM)
2023	0.49	1.19	11.84	5.40
2024	0.92	2.28	38.13	7.55
2025	1.00	2.53	13.18	7.96
2026	0.89	2.24	1.33	7.41
2027	0.77	1.95	0.32	6.85
2028	0.68	1.71	0.30	6.39
2029	0.61	1.50	-	6.00
2030	0.54	1.34	-	5.68
2031	0.49	1.20	-	5.41
2032	0.45	1.08	-	5.19
2033	0.41	0.97	-	4.99
2034	0.37	0.89	-	4.82
2035	0.34	0.81	-	4.67
2036	0.32	0.74	-	4.54
2037	0.29	0.68	-	4.42
2038	0.27	0.63	-	4.32
2039	0.25	0.58	-	4.23
2040	0.24	0.54	-	4.15
2041	0.22	0.49	-	4.07
2042	0.21	0.46	-	4.00
2043	0.18	0.37	-	3.83
Total	**9.94**	**24.17**	**65.11**	**111.88**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2043.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Gaffney Cline

Table AIII.3: Sabria Gross Oil and Gas Production Volumes and Cost Profiles - High Case

Gross Production and Cost Profiles - High Case				
Year	Oil (MMBbl)	Gas (Bscf)	CAPEX (US$ MM)	OPEX (US$ MM)
2022	0.61	1.61	11.84	6.09
2023	1.13	2.94	38.13	8.66
2024	1.31	3.48	13.18	9.63
2025	1.21	3.22	1.33	9.13
2026	1.09	2.87	0.32	8.49
2027	0.99	2.59	0.30	7.96
2028	0.89	2.34	-	7.49
2029	0.82	2.14	-	7.12
2030	0.76	1.96	-	6.80
2031	0.71	1.82	-	6.53
2032	0.66	1.69	-	6.28
2033	0.62	1.57	-	6.07
2034	0.58	1.47	-	5.89
2035	0.55	1.39	-	5.73
2036	0.52	1.31	-	5.58
2037	0.49	1.24	-	5.44
2038	0.47	1.17	-	5.32
2039	0.45	1.12	-	5.22
2040	0.43	1.06	-	5.11
2041	0.41	1.01	-	5.02
2042	0.34	0.81	-	4.66
2043	0.61	1.61	11.84	6.09
Total	**15.03**	**38.81**	**65.11**	**138.24**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2043.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Table AIII.4: Chouech Es Saida Gross Oil and Gas Production Volumes and Cost Profiles - Low Case

Gross Production and Cost Profiles - Low Case				
Year	Oil (MMBbl)	Gas (Bscf)	CAPEX (US$ MM)	OPEX (US$ MM)
2023	0.09	0.02	1.63	2.79
2024	0.07	0.01	0.43	2.66
2025	0.06	-	2.78	2.57
2026	0.05	-	0.21	2.51
2027	0.04	-	0.22	2.45
2028	0.03	-	0.22	2.41
2029	0.03	-	-	2.37
2030	0.03	-	-	2.34
2031	0.02	-	-	2.31
2032	0.02	-	-	2.29
2033	0.02	-	-	2.27
2034	0.01	-	-	2.26
2035	0.01	-	-	2.25
2036	0.01	-	-	2.24
2037	0.01	-	-	2.22
2038	0.00	-	-	2.19
2039	0.00	-	-	2.19
2040	0.00	-	-	2.18
2041	0.00	-	-	2.18
2042	0.00	-	-	2.18
Total	**0.51**	**0.03**	**5.49**	**46.85**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2042.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Table AIII.5: Chouech Es Saida Gross Oil and Gas Production Volumes and Cost Profiles - Best Case

Gross Production and Cost Profiles - Best Case				
Year	Oil	Gas	CAPEX	OPEX
	(MMBbl)	(Bscf)	(US$ MM)	(US$ MM)
2023	0.09	0.03	1.63	2.80
2024	0.08	0.01	0.43	2.70
2025	0.07	0.01	2.78	2.63
2026	0.06	-	0.21	2.57
2027	0.05	-	0.22	2.53
2028	0.05	-	0.22	2.49
2029	0.04	-	-	2.45
2030	0.04	-	-	2.43
2031	0.03	-	-	2.40
2032	0.03	-	-	2.38
2033	0.03	-	-	2.36
2034	0.03	-	-	2.35
2035	0.02	-	-	2.33
2036	0.02	-	-	2.32
2037	0.02	-	-	2.29
2038	0.02	-	-	2.27
2039	0.01	-	-	2.26
2040	0.01	-	-	2.26
2041	0.01	-	-	2.25
2042	0.01	-	-	2.24
Total	**0.72**	**0.05**	**5.49**	**48.31**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2042.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Table AIII.6: Chouech Es Saida Gross Oil and Gas Production Volumes and Cost Profiles - High Case

Gross Production and Cost Profiles - High Case				
Year	Oil	Gas	CAPEX	OPEX
	(MMBbl)	(Bscf)	(US$ MM)	(US$ MM)
2023	0.09	0.03	1.63	2.82
2024	0.08	0.02	0.43	2.72
2025	0.07	0.01	2.78	2.67
2026	0.07	0.01	0.21	2.63
2027	0.06	0.00	0.22	2.59
2028	0.06	-	0.22	2.56
2029	0.05	-	-	2.53
2030	0.05	-	-	2.51
2031	0.05	-	-	2.49
2032	0.04	-	-	2.47
2033	0.04	-	-	2.45
2034	0.04	-	-	2.44
2035	0.04	-	-	2.42
2036	0.04	-	-	2.41
2037	0.03	-	-	2.37
2038	0.02	-	-	2.34
2039	0.02	-	-	2.33
2040	0.02	-	-	2.32
2041	0.02	-	-	2.32
2042	0.02	-	-	2.31
Total	**0.91**	**0.06**	**5.49**	**49.69**

Notes:

1. The volumes represent gross numbers (100% WI).
2. Profiles are shown up to the expiry of the Concession Agreement, with an expected extension of 15 years, at end 2042.
3. Economic cut off has not been applied to the volumes.
4. The gas volumes are sales volumes after allowance for shrinkage, fuel and flare. Capex include facilities.
5. Costs shown are in 2023 Real terms.
6. Numbers may not add up due to rounding.

Appendix IV
Serinus Net Working Interest Cash Flows

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

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	131.35	63.13
5.0%	102.58	49.29
7.5%	91.64	43.86
10.0%	82.41	39.20
12.5%	74.56	35.21
15.0%	67.85	31.77
IRR	100+	100+

Field:	Sabria	
Case:	1P	
	Initial	*Final*
Working Interest:	45.0%	45.0%
Revenue Interest:	45.0%	45.0%

Fiscal Assumptions	Royalty		Corp. Tax
	Oil	*Gas*	
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			3.3 yr DB

Period Beginning	Oil Production MMB	Oil Price US$/Bbl	DMO Production MMB	DMO Price US$/Bbl	Gas 1 Production BCF	Gas 1 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	Pre Tax NCF US$ MM	Export Duty US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-23	0.13	83.48	0.03	75.45	0.35	10.48	16.64	1.62	15.03	15.03		5.33		2.11	7.59		5.07	2.52
Jan-24	0.24	78.64	0.06	71.09	0.69	9.87	30.03	2.91	27.12	27.12		17.50		2.86	6.75		8.53	- 1.78
Jan-25	0.24	79.65	0.06	72.00	0.69	10.00	29.84	2.89	26.95	26.95		6.17		2.89	17.88		8.59	9.30
Jan-26	0.20	81.25	0.05	73.44	0.58	10.20	25.76	2.50	23.26	23.26		0.64		2.72	19.91		7.77	12.14
Jan-27	0.17	82.88	0.04	74.91	0.47	10.40	21.66	2.10	19.56	19.56		0.16		2.54	16.86		6.73	10.13
Jan-28	0.14	84.55	0.03	76.41	0.38	10.61	18.32	1.78	16.54	16.54		0.15		2.40	13.99		5.80	8.18
Jan-29	0.11	86.24	0.03	77.94	0.31	10.82	15.49	1.51	13.99	13.99				2.29	11.70		4.96	6.74
Jan-30	0.10	87.98	0.02	79.49	0.26	11.04	13.22	1.53	11.69	11.69				2.21	9.49		4.53	4.95
Jan-31	0.08	89.74	0.02	81.08	0.21	11.26	11.34	1.31	10.02	10.02				2.14	7.88		3.86	4.02
Jan-32	0.07	91.54	0.02	82.71	0.17	11.49	9.79	1.13	8.66	8.66				2.10	6.56		3.27	3.29
Jan-33	0.06	93.38	0.01	84.36	0.14	11.72	8.40	0.98	7.43	7.43				2.06	5.36		2.72	2.65
Jan-34	0.05	95.26	0.01	86.05	0.11	11.95	7.07	0.82	6.25	6.25				2.03	4.22		2.16	2.06
Jan-35	0.04	97.17	0.01	87.77	0.09	12.19	6.12	0.71	5.41	5.41				2.01	3.39		1.75	1.64
Jan-36	0.04	99.12	0.01	89.52	0.07	12.43	5.26	0.62	4.65	4.65				2.00	2.64		1.37	1.27
Jan-37	0.03	101.11	0.01	91.31	0.05	12.68	4.49	0.53	3.97	3.97				2.00	1.97		1.02	0.94
Jan-38	0.02	103.14	0.00	93.14	0.02	12.94	2.42	0.29	2.13	2.13				1.93	0.20		0.07	0.13
Jan-39	0.02	105.21	0.00	95.00	0.01	13.19	2.25	0.27	1.98	1.98			5.06	1.96	- 5.04			- 5.04
Totals (>01-Jan-23):	1.72	MMBbl	0.43	MMBbl	4.61	BCF	228.11	23.50	204.60	204.60	-	29.95	5.06	38.25	131.35	-	68.22	63.13
Entitlements (>01-Jan-23):	1.53	MMBbl	0.38	MMBbl	4.23	BCF												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

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

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	345.14	156.86
5.0%	239.26	110.37
7.5%	204.64	94.73
10.0%	177.65	82.36
12.5%	156.20	72.42
15.0%	138.89	64.32
IRR	100+	100+

Field:	Sabria	
Case:	2P	
	Initial	Final
Working Interest:	45.0%	45.0%
Revenue Interest:	45.0%	45.0%

Fiscal Assumptions	Royalty Oil	Royalty Gas	Corp. Tax
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			3.3 yr DB

Period Beginning	Oil Production MMB	Oil Price US$/Bbl	DMO Production MMB	DMO Price US$/Bbl	Gas 1 Production BCF	Gas 1 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	Pre Tax NCF US$ MM	Export Duty US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-23	0.18	83.48	0.04	75.45	0.54	10.48	23.55	2.28	21.27	21.27		5.33		2.74	13.20		7.88	5.32
Jan-24	0.33	78.64	0.08	71.09	1.03	9.87	42.05	4.07	37.98	37.98		17.50		3.98	16.50		13.41	3.09
Jan-25	0.36	79.65	0.09	72.00	1.14	10.00	46.38	4.48	41.90	41.90		6.17		4.51	31.21		15.25	15.96
Jan-26	0.32	81.25	0.08	73.44	1.01	10.20	42.07	4.07	38.01	38.01		0.64		4.36	33.01		14.32	18.69
Jan-27	0.28	82.88	0.07	74.91	0.88	10.40	37.46	4.29	33.17	33.17		0.16		4.13	28.88		14.02	14.86
Jan-28	0.25	84.55	0.06	76.41	0.77	10.61	33.68	3.86	29.82	29.82		0.15		3.95	25.72		12.83	12.88
Jan-29	0.22	86.24	0.05	77.94	0.68	10.82	30.39	3.48	26.91	26.91				3.80	23.11		11.73	11.37
Jan-30	0.20	87.98	0.05	79.49	0.60	11.04	27.72	3.18	24.54	24.54				3.68	20.86		10.79	10.07
Jan-31	0.18	89.74	0.04	81.08	0.54	11.26	25.46	2.92	22.54	22.54				3.58	18.95		9.95	9.01
Jan-32	0.16	91.54	0.04	82.71	0.49	11.49	23.59	2.71	20.88	20.88				3.51	17.37		9.22	8.15
Jan-33	0.15	93.38	0.04	84.36	0.44	11.72	21.85	2.51	19.34	19.34				3.45	15.89		8.51	7.38
Jan-34	0.13	95.26	0.03	86.05	0.40	11.95	20.39	2.34	18.05	18.05				3.40	14.65		7.89	6.76
Jan-35	0.12	97.17	0.03	87.77	0.36	12.19	19.11	2.20	16.91	16.91				3.36	13.55		7.34	6.21
Jan-36	0.11	99.12	0.03	89.52	0.33	12.43	18.02	2.07	15.95	15.95				3.34	12.62		6.86	5.76
Jan-37	0.11	101.11	0.03	91.31	0.31	12.68	16.97	1.95	15.01	15.01				3.31	11.70		6.38	5.32
Jan-38	0.10	103.14	0.02	93.14	0.28	12.94	16.06	2.14	13.92	13.92				3.30	10.63		6.33	4.29
Jan-39	0.09	105.21	0.02	95.00	0.26	13.19	15.25	2.03	13.22	13.22				3.29	9.93		5.93	4.00
Jan-40	0.09	107.32	0.02	96.90	0.24	13.46	14.56	1.94	12.62	12.62				3.29	9.33		5.58	3.75
Jan-41	0.08	109.47	0.02	98.84	0.22	13.73	13.85	1.85	12.01	12.01				3.29	8.72		5.22	3.50
Jan-42	0.08	111.67	0.02	100.82	0.21	14.00	13.25	1.77	11.48	11.48				3.29	8.19		4.90	3.29
Jan-43	0.06	113.91	0.02	102.83	0.16	14.28	11.21	1.50	9.71	9.71			5.47	3.12	1.12		3.95	- 2.83
Totals (>01-Jan-23):	3.58	MMBbl	0.89	MMBbl	10.88	BCF	512.87	57.64	455.23	455.23	-	29.95	5.47	74.67	345.14	-	188.28	156.86
Entitlements (>01-Jan-23):	3.15	MMBbl	0.79	MMBbl	9.92	BCF												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

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

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	589.71	246.23
5.0%	392.28	168.30
7.5%	330.08	143.05
10.0%	282.61	123.47
12.5%	245.63	107.99
15.0%	216.30	95.56
IRR	100+	100+

Field:	Sabria	
Case:	3P	
	Initial	*Final*
Working Interest:	45.0%	45.0%
Revenue Interest:	45.0%	45.0%

Fiscal Assumptions	Royalty		Corp. Tax
	Oil	*Gas*	
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			3.3 yr DB

Period Beginning	Oil		DMO		Gas 1		Field Revenue	Royalty	Net Revenue	Contractor Revenue	Expl&Appr Costs	Capital Costs	Aband Costs	Operating Costs	Pre Tax NCF	Export Duty	Corporate Tax	Post Tax NCF
	Production	Price	Production	Price	Production	Price												
	MMB	US$/Bbl	MMB	US$/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
Jan-23	0.22	83.48	0.06	75.45	0.73	10.48	30.27	2.92	27.35	27.35		5.33		2.74	19.28		10.92	8.36
Jan-24	0.41	78.64	0.10	71.09	1.32	9.87	52.22	5.04	47.18	47.18		17.50		3.98	25.70		18.01	7.70
Jan-25	0.47	79.65	0.12	72.00	1.56	10.00	61.86	5.97	55.90	55.90		6.17		4.51	45.21		22.25	22.96
Jan-26	0.44	81.25	0.11	73.44	1.45	10.20	58.34	6.66	51.67	51.67		0.64		4.36	46.68		23.27	23.41
Jan-27	0.39	82.88	0.10	74.91	1.29	10.40	53.28	6.09	47.19	47.19		0.16		4.13	42.90		21.73	21.17
Jan-28	0.35	84.55	0.09	76.41	1.16	10.61	49.11	5.61	43.50	43.50		0.15		3.95	39.39		20.36	19.04
Jan-29	0.32	86.24	0.08	77.94	1.05	10.82	45.43	6.00	39.43	39.43				3.80	35.63		20.31	15.32
Jan-30	0.30	87.98	0.07	79.49	0.96	11.04	42.47	5.61	36.86	36.86				3.68	33.18		19.16	14.02
Jan-31	0.27	89.74	0.07	81.08	0.88	11.26	39.97	5.28	34.69	34.69				3.58	31.10		18.14	12.96
Jan-32	0.25	91.54	0.06	82.71	0.82	11.49	37.93	5.02	32.91	32.91				3.51	29.40		17.28	12.13
Jan-33	0.24	93.38	0.06	84.36	0.76	11.72	35.97	4.76	31.21	31.21				3.45	27.76		16.40	11.36
Jan-34	0.22	95.26	0.06	86.05	0.71	11.95	34.36	4.55	29.81	29.81				3.40	26.41		15.67	10.74
Jan-35	0.21	97.17	0.05	87.77	0.66	12.19	32.94	4.36	28.58	28.58				3.36	25.22		15.01	10.21
Jan-36	0.20	99.12	0.05	89.52	0.63	12.43	31.78	4.21	27.57	27.57				3.34	24.24		14.45	9.78
Jan-37	0.19	101.11	0.05	91.31	0.59	12.68	30.58	4.05	26.53	26.53				3.31	23.22		13.87	9.35
Jan-38	0.18	103.14	0.04	93.14	0.56	12.94	29.59	3.92	25.67	25.67				3.30	22.37		13.38	8.99
Jan-39	0.17	105.21	0.04	95.00	0.53	13.19	28.70	4.09	24.61	24.61				3.29	21.32		13.83	7.49
Jan-40	0.16	107.32	0.04	96.90	0.50	13.46	27.98	3.99	23.99	23.99				3.29	20.70		13.43	7.27
Jan-41	0.15	109.47	0.04	98.84	0.48	13.73	27.19	3.88	23.31	23.31				3.29	20.02		13.00	7.02
Jan-42	0.15	111.67	0.04	100.82	0.45	14.00	26.54	3.79	22.75	22.75				3.29	19.46		12.64	6.82
Jan-43	0.12	113.91	0.03	102.83	0.37	14.28	22.28	3.18	19.09	19.09			5.47	3.12	10.50		10.38	0.12
Totals (>01-Jan-23):	5.41	MMBbl	1.35	MMBbl	17.46	BCF	798.78	98.98	699.80	699.80	-	29.95	5.47	74.67	589.71	-	343.48	246.23
Entitlements (>01-Jan-23):	4.70	MMBbl	1.17	MMBbl	15.81	BCF												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

Table AIV.4: Serinus Net Working Interest Cash Flow – Chouech Es Sadia Proved Case

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	- 10.51	- 10.51
5.0%	- 9.67	- 9.67
7.5%	- 9.29	- 9.29
10.0%	- 8.93	- 8.93
12.5%	- 8.59	- 8.59
15.0%	- 8.27	- 8.27
IRR	0.0%	0.0%

Field:	CS+ES	
Case:	1P	
	Initial	*Final*
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Fiscal Assumptions	Royalty		Corp. Tax
	Oil	*Gas*	
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			10.0 yr DB

Period Beginning	Oil		DMO		Gas 1		Field Revenue	Royalty	Net Revenue	Contractor Revenue	Expl&Appr Costs	Capital Costs	Aband Costs	Operating Costs	Pre Tax NCF	Export Duty	Corporate Tax	Post Tax NCF
	Production MMB	Price US$/Bbl	Production MMB	Price US$/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
Jan-23	0.09	83.48		75.45	0.02	9.22	7.60	1.14	6.46	6.46		1.63		2.79	2.04			2.04
Jan-24	0.07	78.64		71.09	0.01	8.69	5.61	0.84	4.77	4.77		0.44	14.18	2.71	- 12.55			- 12.55
Totals (>01-Jan-23):	**0.16**	**MMBbl**	**-**	**MMBbl**	**0.03**	**BCF**	**13.21**	**1.98**	**11.23**	**11.23**	**-**	**2.07**	**14.18**	**5.50**	**- 10.51**	**-**	**-**	**- 10.51**
Entitlements (>01-Jan-23):	**0.13**	**MMBbl**	**-**	**MMBbl**	**0.03**	**BCF**												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

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Table AIV.5: Serinus Net Working Interest Cash Flow – Chouech Es Sadia Proved plus Probable Case

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	-10.58	-10.58
5.0%	-6.20	-6.20
7.5%	-4.62	-4.62
10.0%	-3.35	-3.35
12.5%	-2.31	-2.31
15.0%	-1.46	-1.46
IRR	0.0%	0.0%

Field:	CS+ES	
Case:	2P	
	Initial	***Final***
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Fiscal Assumptions	Royalty		Corp. Tax
	Oil	*Gas*	
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			10.0 yr DB

Period Beginning	Oil		DMO		Gas 1		Field	Royalty	Net	Contractor	Expl&Appr	Capital	Aband	Operating	Pre Tax	Export	Corporate	Post Tax
	Production	Price	Production	Price	Production	Price	Revenue		Revenue	Revenue	Costs	Costs	Costs	Costs	NCF	Duty	Tax	NCF
	MMB	US$/Bbl	MMB	US$/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
Jan-23	0.09	83.48		75.45	0.03	9.22	7.83	1.17	6.65	6.65		1.63		2.80	2.22			2.22
Jan-24	0.08	78.64		71.09	0.01	8.69	6.06	0.91	5.15	5.15		0.44		2.75	1.96			1.96
Jan-25	0.07	79.65		72.00	0.01	8.80	5.29	0.79	4.50	4.50		2.90		2.73	-1.13			-1.13
Jan-26	0.06	81.25		73.44		8.98	4.71	0.71	4.01	4.01		0.23		2.73	1.05			1.05
Jan-27	0.05	82.88		74.91		9.16	4.27	0.64	3.63	3.63		0.23		2.73	0.66			0.66
Jan-28	0.05	84.55		76.41		9.34	3.91	0.59	3.32	3.32		0.24		2.75	0.33			0.33
Jan-29	0.04	86.24		77.94		9.53	3.58	0.54	3.04	3.04				2.76	0.28			0.28
Jan-30	0.04	87.98		79.49		9.72	3.30	0.49	2.80	2.80			15.96	2.79	-15.95			-15.95
Totals (>01-Jan-23):	**0.47**	**MMBbl**	**-**	**MMBbl**	**0.05**	**BCF**	**38.94**	**5.84**	**33.10**	**33.10**	**-**	**5.67**	**15.96**	**22.05**	**-10.58**	**-**	**-**	**-10.58**
Entitlements (>01-Jan-23):	**0.40**	**MMBbl**	**-**	**MMBbl**	**0.04**	**BCF**												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

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Table AIV.6: Serinus Net Working Interest Cash Flow – Chouech Es Sadia Proved plus Probable plus Possible Case

Nominal Net Present Values as at 01-Jan-23 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	- 6.51	- 6.51
5.0%	- 0.97	- 0.97
7.5%	0.65	0.65
10.0%	1.78	1.78
12.5%	2.57	2.57
15.0%	3.11	3.11
IRR	0.0%	0.0%

Field:	CS+ES	
Case:	3P	
	Initial	*Final*
Working Interest:	100.0%	100.0%
Revenue Interest:	100.0%	100.0%

Fiscal Assumptions	Royalty		Corp. Tax
	Oil	*Gas*	
Tax Rate/State Share:	0.00%	0.00%	50.0%
Max Cost Recovery:	100.0%	100.0%	
Depreciation:			10.0 yr DB

Period Beginning	Oil		DMO		Gas 1		Field	Royalty	Net	Contractor	Expl&Appr	Capital	Aband	Operating	Pre Tax	Export	Corporate	Post Tax
	Production	Price	Production	Price	Production	Price	Revenue		Revenue	Revenue	Costs	Costs	Costs	Costs	NCF	Duty	Tax	NCF
	MMB	US$/Bbl	MMB	US$/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
Jan-23	0.09	83.48		75.45	0.03	9.22	7.99	1.20	6.79	6.79		1.63		2.82	2.34			2.34
Jan-24	0.08	78.64		71.09	0.02	8.69	6.39	0.96	5.43	5.43		0.44		2.78	2.22			2.22
Jan-25	0.07	79.65		72.00	0.01	8.80	5.80	0.87	4.93	4.93		2.90		2.78	- 0.74			- 0.74
Jan-26	0.07	81.25		73.44	0.01	8.98	5.38	0.81	4.57	4.57		0.23		2.79	1.56			1.56
Jan-27	0.06	82.88		74.91	0.00	9.16	5.02	0.75	4.26	4.26		0.23		2.80	1.23			1.23
Jan-28	0.06	84.55		76.41		9.34	4.75	0.71	4.03	4.03		0.24		2.82	0.97			0.97
Jan-29	0.05	86.24		77.94		9.53	4.50	0.68	3.83	3.83				2.85	0.98			0.98
Jan-30	0.05	87.98		79.49		9.72	4.30	0.65	3.66	3.66				2.88	0.78			0.78
Jan-31	0.05	89.74		81.08		9.91	4.13	0.62	3.51	3.51				2.91	0.60			0.60
Jan-32	0.04	91.54		82.71		10.11	3.99	0.60	3.39	3.39				2.95	0.44			0.44
Jan-33	0.04	93.38		84.36		10.31	3.84	0.58	3.26	3.26				2.99	0.28			0.28
Jan-34	0.04	95.26		86.05		10.52	3.72	0.56	3.16	3.16			17.28	3.03	- 17.15			- 17.15
Totals (>01-Jan-23):	**0.70**	**MMBbl**	**-**	**MMBbl**	**0.06**	**BCF**	**59.80**	**8.97**	**50.83**	**50.83**	**-**	**5.67**	**17.28**	**34.40**	**- 6.51**	**-**	**-**	**- 6.51**
Entitlements (>01-Jan-23):	**0.59**	**MMBbl**	**-**	**MMBbl**	**0.05**	**BCF**												

Notes:

1. Cash flows are shown only up to the earlier of the concession expiry or the economic limit.
2. Entitlements exclude Royalty.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.