Project Madero, Competent Person's Report

Prepared for

Cairn Energy Plc

10 June 2021

Gaffney Cline

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Project Madero, Competent Person's Report

Introduction

At the request of Cairn Energy Plc (Cairn), Gaffney, Cline & Associates Limited (GaffneyCline) has prepared this Competent Person's Report (CPR) on various onshore assets in the Western Desert (Egypt) in which the Shell group of companies (Shell or the Vendor) holds an interest (the Shell Western Desert Assets or the Assets). Shell has offered its interests in these assets for sale, and GaffneyCline understands that Cairn and its Consortium partner Cheiron Petroleum Company (Cheiron) have signed a Sales and Purchase Agreement (SPA) to acquire the assets subject to certain requirements being met. Cairn and Cheiron will each hold a 50% working interest in the Consortium, with Cheiron as the Operator. The CPR has been prepared for inclusion in a Circular to be issued by Cairn to its shareholders ahead of a vote to approve the deal.

In preparing this report, GaffneyCline had access to a data set of technical and commercial information made available by the Vendor in a Virtual Data Room (VDR) and in a "virtual Physical Data Room" (vPDR). This data set included details of concession interests and agreements, geological and geophysical data, interpretations and technical reports, historical production and engineering data, cost and commercial data, and approved development plans as at the Effective Date of 31st December 2019. The vPDR also included reservoir models. In addition, results of some wells drilled in the first half of 2020 were taken into account in preparing the estimates of Reserves as at 31st December 2019.

GaffneyCline was also supplied with the Consortium's Business Plan (BP), developed during the due diligence process conducted by the Consortium in January-June 2020. This BP has been used as the basis for the classification of hydrocarbon resources as Reserves and Contingent Resources. The report is prepared assuming that the Consortium executes the activities described in the BP according to the schedule set out therein.

The purpose of the CPR is to provide an independent evaluation of the Reserves and Contingent Resources of the Assets at 31st December 2019, which is the effective date of the SPA. The review process and preparation of the CPR was carried out during the months of January to July 2020. Considering the volatility in the global oil markets in 2020, GaffneyCline ran a sensitivity assuming an oil price US$10/Bbl lower than the year-end 2019 oil price scenario used as the reference case in this CPR. The results of this sensitivity are presented in Section 4.4.

In addition, given the time that has elapsed since the Effective Date of the estimates of Reserves and net present values (NPVs), to meet the requirements of the FCA, GaffneyCline has included tables showing the Reserves that would remain as at 31st December 2020 and the corresponding NPVs at that date. For this purpose, GaffneyCline has taken out the forecast 2020 production and costs, but has not made any other adjustment to the forecasts made as at 31st December 2019. This is considered a reasonable assumption given that actual production from January to December 2020 has been comparable, in the aggregate, with GaffneyCline's estimates made as at 31st December 2019. An updated (31st December 2020) Brent crude oil price scenario has been used. The resulting tables are presented below and in Appendix IV.

Since 31st December 2020, GaffneyCline has reviewed information regarding the performance of the Assets in 2020, and compared forecasts (including production and costs) against those set out in the CPR. GaffneyCline notes the deferral in the implementation of the drilling schedule planned by the Consortium, which may defer some production that was forecast to be produced in 2021. The deferral could impact the NPVs but is unlikely to have a material impact on the Reserves. However, any reduction in the NPVs will be offset by the recovery in oil prices since the beginning of 2021, which makes the price scenario used by GaffneyCline appear conservative in the short term. GaffneyCline therefore believes that the Reserves and NPVs as at 31st December 2020 reported herein remain valid in the aggregate (see Appendix IV).

GaffneyCline believes that, other than the deferral described above, all information in the CPR remains valid.

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 terms and abbreviations is included as Appendix I.

Summary

Licence Summary

Table 1 lists the licences in Egypt in which Shell holds a working interest (WI) as at 31st December 2019, which are included in the sales process. Reserves and Contingent Resources have been attributed to the majority of these licences; Prospective Resources (i.e. exploration prospects and leads) are not considered in this report, either in the exploration licences or within the production and development licences.

GaffneyCline understands that Cairn has a 50% share in the Consortium. Therefore, Cairn's WI in the Assets will be half of the Shell WIs shown in Table 1.

Table 1: Shell's Onshore Western Desert Portfolio

Area	Concession & Exploration Blocks	Shell WI (%)	Status	Final License Expiry
Obaiyed Area	Obaiyed	100%	Production	22 August 2029
	North Matruh (NM)	100%	Development	25 years from 1st gas
	North Um Baraka (NUMB)	100%	Development	26 April 2043
Badr El Din (BED)	Sitra	100%	Production	01 December 2025
	Badr El Din 19 & 20 (BED)	100%	Production	BED 19: 15 October 2036 BED-20: 31 May 2044
	Badr El Dine 2, 16 & 17 (BED 2, 15 & 17)	100%	Production	10 April 2034
	Badr El Dine 3, 15 & 18 (BED 3, 15 & 18)	100%	Production	27 April 2026
	North Alam El Shawish (NAES)	100%	Production/ Development	17 April 2042
Alam El Shawish	Alam El Shawish West (AESW)	40%	Production	Assil, Al Karam & Al Magd: 1 April 2033 Al Barq & Bahga: 28 May 2032
North East Abu Gharadig (NEAG)	NEAG Tiba	52%	Production	JG: 20 February 2027 JD: 19 May 2029 JD Apollonia Gas: 19 May 2034 Sheiba: 11 May 2029
	NEAG Extension (NEAG Ext)	52%	Production	NEAG 1: 18 November 2032 NEAG 2&3: 15 March 2034 NEAG 4: 18 February 2036 NEAG 5: 03 November 2036
Abu Sennan	South Abu Sennan	100%	Exploration	18 January 2023 (First Exploration Period)
Horus	South East Horus	100%	Exploration	18 January 2024 (First Exploration Period)
El Fayum	West El Fayum	100%	Exploration	18 January 2024 (First Exploration Period)

Overview

The portfolio is composed of a variety of oil and gas onshore assets in multiple stages of development, most of which hold additional opportunities to be explored and exploited. The assets benefit from being in a low cost environment, with existing facilities, and with infrastructure available within the surrounding area.

In the Matruh Basin, further development of the Obaiyed field, its satellites, and the undeveloped Teen field are planned. Gas-bearing sandstones are proven but relatively tight, and realisation of the full potential will rely on successful exploitation of marginal, possibly discontinuous reservoirs, partly via application of multi-stage fracking of horizontal wells.

In the Abu Gharadig Basin, there are several well-established oil and gas fields in the BED, Sitra, AESW and NEAG areas with multiple stacked reservoirs. Infill with additional production and injection wells is expected to add to the ultimate recovery. In the gas-bearing reservoirs, this partly relies on exploiting low grade reservoir between the main sandstone bodies, which is only locally proven. In the oil-bearing reservoirs, recent successful wells have demonstrated the sandstone reservoir fairways to be more extensive than previous thought.

Also in the Abu Gharadig Basin, in the NAES area, the recent appraisal of the BTE discovery shows the existence of a significant undeveloped gas field. However, further work is needed to optimize the development of the deep, relatively high temperature, and tight reservoirs found, not all of which are proven by production testing to date.

On review of the overall facilities and infrastructure assets, there is considered to be adequate ullage provided in all the processing facilities, with no foreseeable bottlenecks for production moving forward. This assurance is provided through the planned capital expenditure program to expand facility capacities and capability. There are challenges for the facilities and infrastructure, especially as they are ageing across the field, with work planned at Obaiyed, BED 3 and NEAG in the short term to ensure reliability of equipment and facilities for continued uninterrupted production. As long as the asset integrity work program is delivered, it should provide adequate assurance in terms of reliability and production efficiency. The overall drilling expenditure across the field is predicated on matching the current Consortium's cost performance, and this will require delivery of the reduction in rig rates and lower overall costs from renegotiated contracts to ensure there is no negative impact on the current plans.

For the operating costs, the planned electrification program provides improved reliability, environmental performance and significant cost improvement through reduced diesel consumption. The operating costs reflect the change to a new Consortium's operating practices and organisational design, which will need to be carefully implemented to ensure knowledge retention and transition is smooth from the Vendor's handover. The operating costs in addition incorporate the assumption of continued 3rd party use of processing and transportation infrastructure owned by the Consortium, this usage level will need to be maintained as per the current plan to ensure no negative impact on operating costs is felt in the near term.

From an economic perspective, using the hydrocarbon pricing assumption detailed in the economics section, most assets continue production for at least 5 years and generate materially positive NPVs; several have the potential to continue economic production beyond the current license end. Approximately a third of the value from hydrocarbon sales is generated by gas subject to fixed prices under existing Gas Sales Agreements, reducing the exposure to fluctuations in hydrocarbon market prices. However, some assets with a larger proportion of liquids production could become uneconomic earlier if hydrocarbon liquids prices remain lower than those assumed here.

Reserves Summary

On the basis of technical and other information made available, GaffneyCline hereby provides the following statement of oil, condensate and gas Reserves in the Assets as at 31st December 2019 (Table 2).

For the reasons mentioned in the Introduction, the Reserves that would remain as at 31st December 2020, calculated simply by taking out the forecast 2020 production and costs and re-running the economic limit tests with a revised oil price scenario, are shown in Table 3.

Table 2: Summary of Reserves as at 31st December 2019

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	17.1	22.2	26.8	100.0	6.3	7.6	8.6	50.0	3.2	3.8	4.3
NUMB	0.2	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.1	0.1	0.1
NM	5.0	10.0	19.8	100.0	2.0	3.4	5.0	50.0	1.0	1.7	2.5
BED 2	2.9	6.0	8.3	100.0	1.2	2.4	3.1	50.0	0.6	1.2	1.6
BED 3	10.7	15.3	20.5	100.0	4.9	6.6	7.6	50.0	2.5	3.3	3.8
Sitra	6.3	11.9	17.3	100.0	2.9	5.5	6.6	50.0	1.4	2.7	3.3
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	6.0	8.9	12.7	52.0	1.5	1.8	2.3	26.0	0.7	0.9	1.2
NEAG Ext.	8.8	12.8	18.7	52.0	2.3	3.1	4.2	26.0	1.2	1.6	2.1
AESW	16.9	30.2	45.1	40.0	2.8	4.7	5.7	20.0	1.4	2.3	2.8
Total	**74.0**	**117.5**	**169.4**		**24.0**	**35.3**	**43.4**		**12.0**	**17.6**	**21.7**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	367.1	425.7	483.0	100.0	137.3	147.4	157.2	50.0	68.6	73.7	78.6
NUMB	14.5	15.0	15.5	100.0	6.7	6.9	7.1	50.0	3.4	3.5	3.6
NM	46.4	76.8	128.0	100.0	18.5	25.9	32.5	50.0	9.3	12.9	16.3
BED 2	9.3	42.4	76.4	100.0	3.7	18.2	29.8	50.0	1.8	9.1	14.9
BED 3	47.1	60.8	75.0	100.0	21.7	26.9	28.2	50.0	10.9	13.5	14.1
Sitra	21.4	32.1	42.3	100.0	9.9	14.8	16.9	50.0	4.9	7.4	8.4
NAES	1.1	24.6	36.7	100.0	0.5	10.8	16.1	50.0	0.2	5.4	8.1
NEAG Tiba	16.7	23.1	32.2	52.0	4.1	5.0	6.3	26.0	2.1	2.5	3.1
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	473.3	616.2	785.8	40.0	77.6	94.2	99.5	20.0	38.8	47.1	49.8
Total	**997.0**	**1,316.8**	**1,674.9**		**279.9**	**350.2**	**393.6**		**140.0**	**175.1**	**196.8**

Notes:
1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 3: Summary of Reserves[3] as at 31st December 2020

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	15.1	20.2	24.8	100.0	5.8	7.1	8.1	50.0	2.9	3.5	4.0
NUMB	0.1	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.0	0.0	0.0
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.7
BED 2	1.0	3.8	6.0	100.0	0.4	1.7	2.4	50.0	0.2	0.8	1.2
BED 3	7.8	12.0	16.9	100.0	3.6	5.5	6.8	50.0	1.8	2.7	3.4
Sitra	0.0	9.9	15.2	100.0	0.0	4.6	6.5	50.0	0.0	2.3	3.2
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	5.1	7.9	11.7	52.0	1.4	1.8	2.3	26.0	0.7	0.9	1.1
NEAG Ext.	6.0	9.9	15.1	52.0	1.7	2.6	3.6	26.0	0.8	1.3	1.8
AESW	15.1	27.4	42.6	40.0	2.5	4.5	5.7	20.0	1.3	2.3	2.8
Total	**55.2**	**101.3**	**152.2**		**17.4**	**31.3**	**40.7**		**8.7**	**15.7**	**20.4**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	320.1	378.2	435.0	100.0	130.0	140.4	150.2	50.0	65.0	70.2	75.1
NUMB	9.1	9.6	9.9	100.0	4.2	4.4	4.6	50.0	2.1	2.2	2.3
NM	46.4	76.8	128.0	100.0	18.5	27.4	34.7	50.0	9.3	13.7	17.3
BED 2	4.1	33.4	67.0	100.0	1.8	15.1	27.6	50.0	0.9	7.5	13.8
BED 3	36.7	49.6	63.3	100.0	16.9	22.8	25.7	50.0	8.5	11.4	12.9
Sitra	0.0	22.1	31.4	100.0	0.0	10.2	13.5	50.0	0.0	5.1	6.7
NAES	0.0	23.2	35.3	100.0	0.0	10.2	15.5	50.0	0.0	5.1	7.8
NEAG Tiba	12.1	18.3	27.2	52.0	3.3	4.2	5.5	26.0	1.7	2.1	2.8
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	418.3	547.6	729.5	40.0	68.5	89.4	97.4	20.0	34.3	44.7	48.7
Total	**846.8**	**1,158.8**	**1,526.6**		**243.3**	**324.1**	**374.6**		**121.6**	**162.0**	**187.3**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Reserves are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

NPV Summary

Reference Net Present Values (NPVs) at 10% discount rate (NPV10) have been attributed to the Proved, the Proved plus Probable, and the Proved plus Probable plus Possible Reserves as at 31st December 2019. These are summarized in Table 4.

GaffneyCline's own 1Q 2020 Brent crude oil price scenario, adjusted for quality and location, has been used in preparing these NPVs. In light of the recent volatility in global crude prices, a sensitivity to a lower oil price scenario has been evaluated, the results of which are summarized in Section 4.

For the reasons mentioned in the Introduction, the NPVs as at 31st December 2020 of the Reserves that would remain as at 31st December 2020 are shown in Table 5. GaffneyCline's own 1Q 2021 Brent crude oil price scenario, adjusted for quality and location, has been used in preparing these NPVs.

All NPVs quoted are those exclusively attributable to Shell's Net Entitlement Reserves in the properties under review.

Table 4: Summary of Post-Tax NPV10 of Future Cash Flow from Reserves, as at 31st December 2019

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	287.6	351.2	411.4	143.8	175.6	205.7
NUMB	18.7	19.4	20.0	9.3	9.7	10.0
NM	7.9	72.3	138.5	3.9	36.2	69.2
BED 2	30.4	58.7	81.4	15.2	29.4	40.7
BED 3	101.5	192.0	239.4	50.8	96.0	119.7
Sitra	33.1	139.7	195.8	16.5	69.9	97.9
NAES	0.7	4.5	11.7	0.3	2.2	5.8
NEAG Tiba	23.9	40.7	62.1	11.9	20.4	31.1
NEAG Ext	41.2	61.7	89.2	20.6	30.9	44.6
AESW	118.8	204.0	243.3	59.4	102.0	121.7
Total	**663.6**	**1,144.4**	**1,492.9**	**331.8**	**572.2**	**746.4**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Table 5: Summary of Post-Tax NPV10[2] of Future Cash Flow from Reserves, as at 31st December 2020

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	216.5	276.0	332.8	108.2	138.0	166.4
NUMB	11.5	12.2	12.7	5.7	6.1	6.4
NM	-6.3	64.5	131.1	-3.2	32.2	65.6
BED 2	4.7	27.3	50.6	2.3	13.6	25.3
BED 3	26.3	119.8	178.3	13.2	59.9	89.1
Sitra	0.0	76.7	161.9	0.0	38.4	81.0
NAES	0.0	3.7	11.4	0.0	1.8	5.7
NEAG Tiba	12.9	29.2	47.7	6.5	14.6	23.9
NEAG Ext	14.0	33.4	57.0	7.0	16.7	28.5
AESW	89.4	188.8	228.1	44.7	94.4	114.1
Total	**368.9**	**831.4**	**1,211.7**	**184.5**	**415.7**	**605.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. NPVs are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
3. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Contingent Resource Summary

On the basis of technical and other information made available, GaffneyCline hereby provides the following statement of oil, condensate and gas Contingent Resources as at 31st December 2019 (Table 6).

Contingent Resources are shown both as gross volumes and net to Shell's interest on a Working Interest (WI) basis, i.e. Shell's Working Interest fraction of the gross volumes. The WI basis volumes do not represent Shell's actual Net Entitlement under the terms of the Contracts that govern the assets, which would be lower. The WI basis volumes are quoted here since the development projects are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the Net Entitlement.

Table 6: Summary of Contingent Resources as at 31st December 2019

(a) Oil and Condensate

Assets	Gross Contingent Resources (MMBbl)			WI (%)	Shell Net (WI Basis) Contingent Resources (MMBbl)			50% WI (%)	50% of Shell Net (WI Basis) Contingent Resources (MMBbl)		
	1C	2C	3C		1C	2C	3C		1C	2C	3C
Obaiyed	4.2	7.0	9.7	100	4.2	7.0	9.7	50.0	2.1	3.5	4.9
NUMB	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NM	0.9	1.9	4.1	100	0.9	1.9	4.1	50.0	0.5	1.0	2.1
BED 2	1.3	2.3	3.7	100	1.3	2.3	3.7	50.0	0.7	1.2	1.9
BED 3	0.2	0.6	1.1	100	0.2	0.6	1.1	50.0	0.1	0.3	0.6
BED 19/20	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
Sitra	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NAES	0.1	0.2	0.5	100	0.1	0.2	0.5	50.0	0.1	0.1	0.3
NEAG Tiba	0.9	1.0	1.5	52	0.5	0.5	0.8	26.0	0.3	0.3	0.4
NEAG Ext	0.0	0.0	0.0	52	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	2.1	4.9	7.8	40	0.8	2.0	3.1	20.0	0.4	1.0	1.6
Total	**9.7**	**17.9**	**28.4**		**8.0**	**14.5**	**23.0**		**4.0**	**7.3**	**11.5**

(b) Natural Gas

Assets	Gross Contingent Resources (Bscf)			WI (%)	Shell Net (WI Basis) Contingent Resources (Bscf)			50% WI (%)	50% of Shell Net (WI Basis) Contingent Resources (Bscf)		
	1C	2C	3C		1C	2C	3C		1C	2C	3C
Obaiyed	72.5	106.1	150.6	100	72.5	106.1	150.6	50.0	36.3	53.1	75.3
NUMB	7.4	14	23.4	100	7.4	14.0	23.4	50.0	3.7	7.0	11.7
NM	6.2	10.9	20.3	100	6.2	10.9	20.3	50.0	3.1	5.5	10.2
BED 2	26.3	58.6	107.8	100	26.3	58.6	107.8	50.0	13.2	29.3	53.9
BED 3	13.4	28.1	46.3	100	13.4	28.1	46.3	50.0	6.7	14.1	23.2
BED 19/20	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
Sitra	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NAES	118.6	219.1	347.9	100	118.6	219.1	347.9	50.0	59.3	109.6	174.0
NEAG Tiba	1.2	1.8	3.1	52	0.6	0.9	1.6	26.0	0.3	0.5	0.8
NEAG Ext	0.0	0.0	0.0	52	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	76.7	92.8	117.4	40	30.7	37.1	47.0	20.0	15.4	18.6	23.5
Total	**322.3**	**531.4**	**816.8**		**275.7**	**474.8**	**744.9**		**137.9**	**237.4**	**372.5**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. Net (WI Basis) Contingent Resources in this table are Shell's Working Interest fraction of the Gross Resources; they do not represent Shell's actual Net Entitlement under the terms of the Contracts that govern the asset, which would be lower.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead 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 and the different basis on which the volumes are determined.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

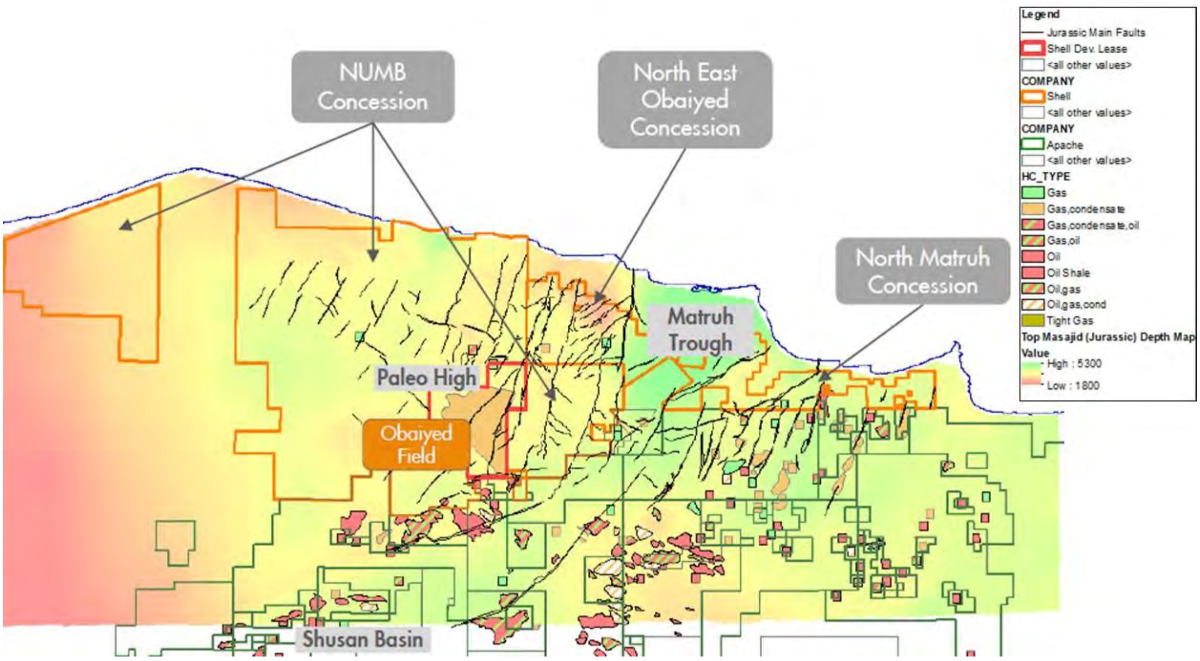
Discussion

1 Matruh Basin

1.1 Regional Geology

The Matruh Basin assets include the contract areas adjacent to the Mediterranean coast (Figure 1). The main Matruh Trough is an approximately NE-SW trending rift basin running through the centre of the area, normal to the continental margin, with subordinate faulting varying from the same NE-SW orientation to E-W. Rifting was active in the Triassic to Early Cretaceous, succeeded by a post-rift phase in the Late Cretaceous. Propagation of stresses along the continental margin during the latest Cretaceous and Early Cenozoic, as a result of Tethyan ocean closure, led to inversion and the local overprint by a ENE-WSW fault trend. Post Eocene, the area is one of passive subsidence on the Mediterranean margin.

Figure 1: Structural Elements of Matruh Basin

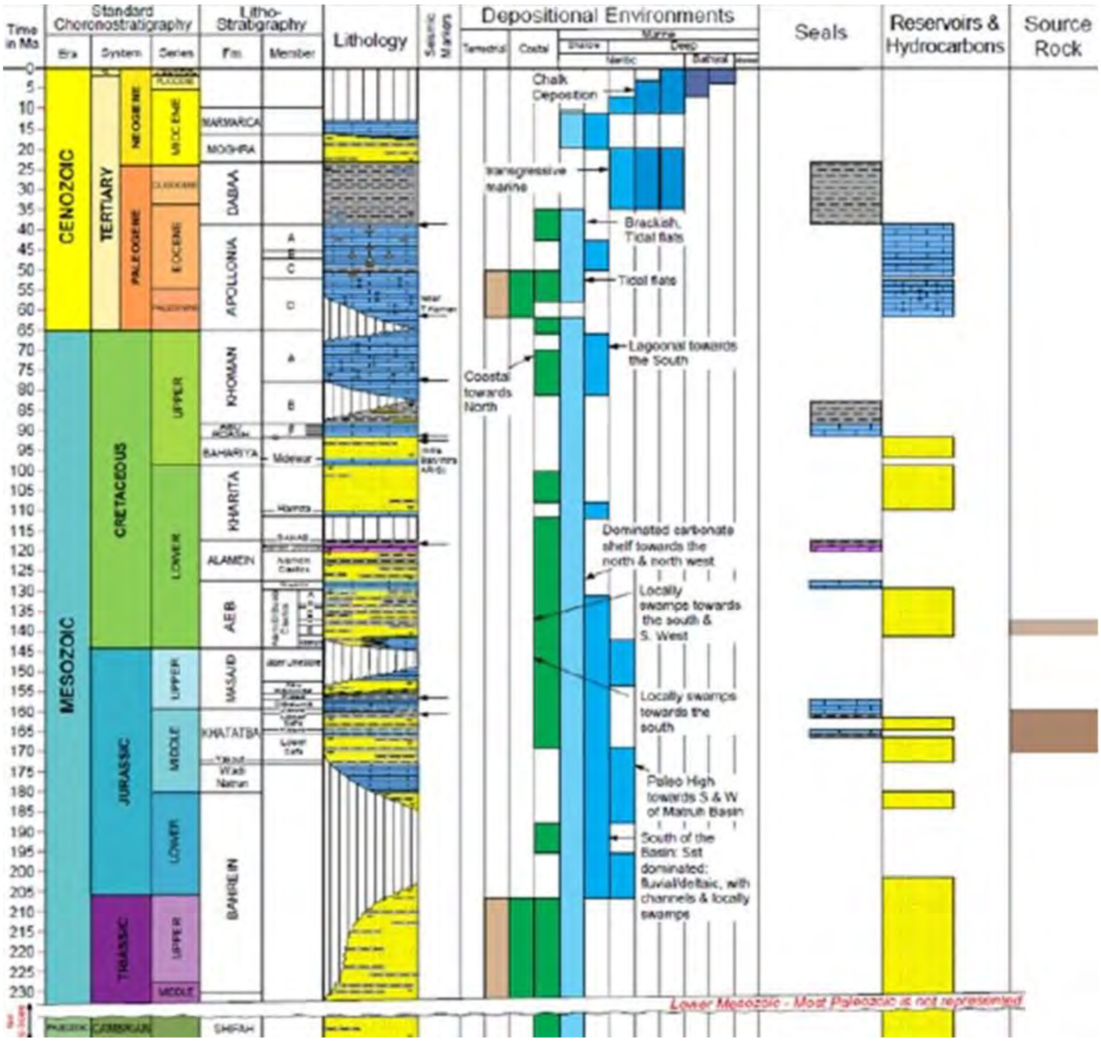


Source: Vendor VDR

The overall stratigraphy is shown in Figure 2. An eroded basement of Palaeozoic clastics is locally seen in the wells which represents the pre-rift phase. An initial phase of Triassic sandstones represents the earliest rift phase. This was followed by a mix of clastic and carbonate sedimentation in the Jurassic and Lower Cretaceous, as a result of the complex interplay of local rifting and overall sea level. Regional carbonate sedimentation dominates the later Cretaceous and Cenozoic stages of the basin's history.

Reservoirs relevant to the plays in the area are in the Safa Formation sandstones (Middle Jurassic), predominantly for gas, with some minor prospectivity attached to underlying Palaeozoic sandstones. There is also some oil potential in the Lower Cretaceous Alam el Bueib sandstones.

Figure 2: Matruh Basin Stratigraphy



Source: Vendor VDR

Source rocks are in the Khatatba Formation, which is equivalent to and interleaves with the Safa Formation, providing close juxtaposition of source and reservoir. This generates gas over most of the area, but modelling and hydrocarbon distribution show an oil fairway in the northwestern part of the area, in the NUMB contract area. Oil is also generated locally from source rocks in the Alam el Bueib Formation.

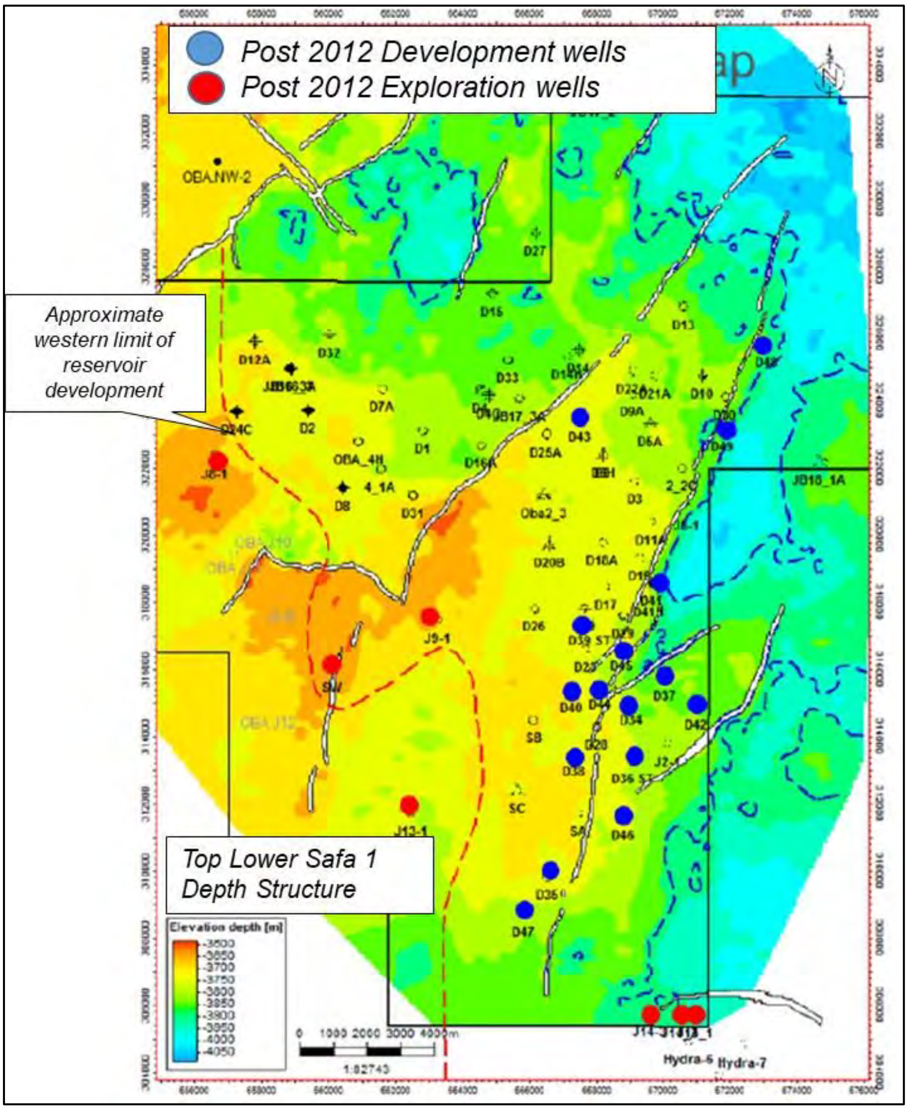
1.2 Obaiyed

1.2.1 Asset Description

1.2.1.1 Structure and Trap

Obaiyed is the principal gas and condensate field of the area, consisting of the main Obaiyed Field and the smaller J14 satellite to the south. It overlies a set of NW-SE trending fault blocks, which originally formed a palaeohigh, onto which reservoirs (Upper and Lower Safa Formation) pinched out from NE to SW. Trapping is thus partly structural, but with an element of stratigraphic closure to the southwest. Top Lower Safa Formation depth structure is depicted in Figure 3. GWC is for the most part interpreted as field-wide at -3,875 m subsea, but there is evidence for some fault compartmentalization, and hence variation in GWC on the northeastern flank, notably at D-48 where the GDT is at -3,910 m subsea (Figure 3).

Figure 3: Obaiyed Field. Top Lower Safa Formation Depth Structure (m)



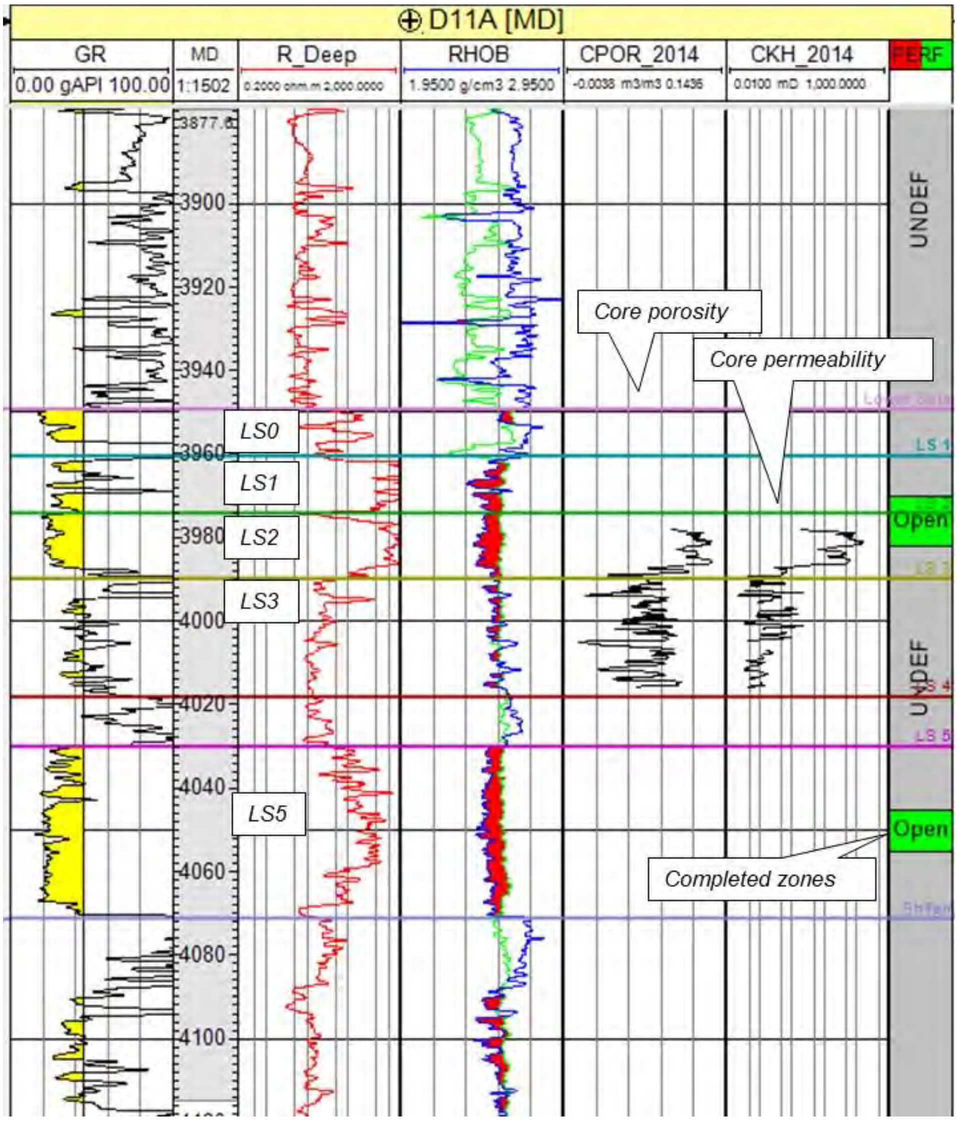
Source: Vendor VDR

1.2.1.2 Reservoir

Reservoirs in both Upper and Lower Safa Formations are divided into subunits (US 1 to 4.2) and (LS 1-5). For practical purposes, however, the Lower Safa can be simply divided into an upper unit (LS1-3) and lower unit (LS5), in which the bulk of the gas resource resides.

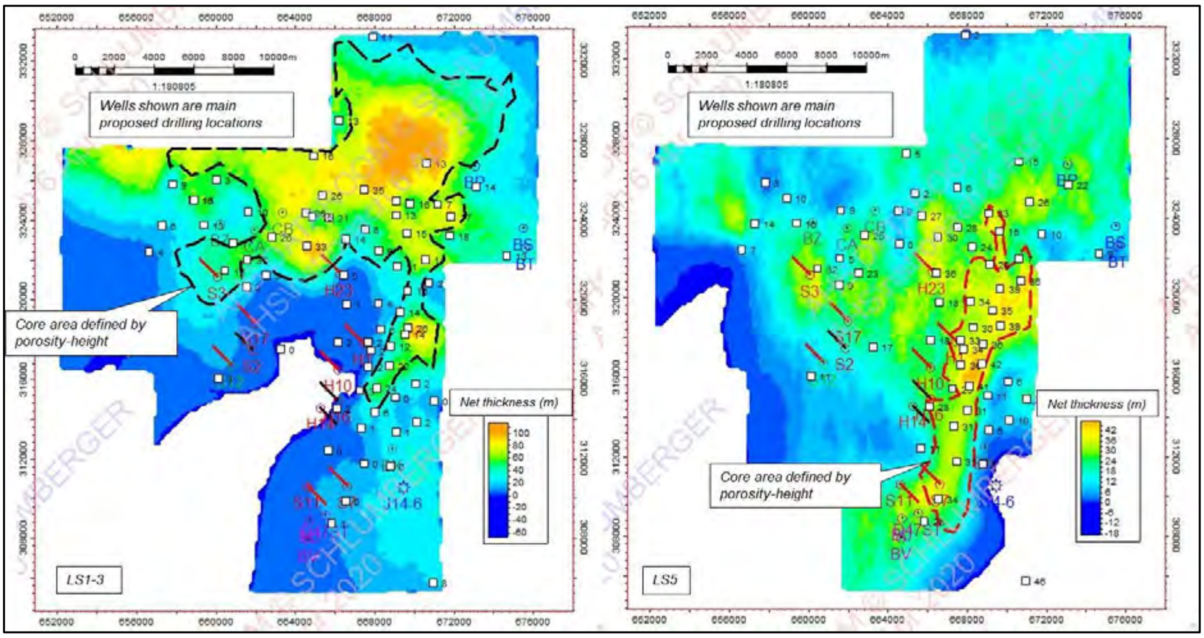
A representative reservoir section is shown in Figure 4. Reservoirs are tight, with porosities typically 7-8%, but rarely up to 13%. Core data suggest a conventional cut-off of approximately 6%. Lower Safa sandstones are extensive across the field, but pass laterally into tighter and/or more argillaceous reservoirs on the southwest flank. This has the effect of creating tighter reservoir facies, but also introduces areas of so-called "lean" facies, at the base of each of the productive units. These are understood to relate to lithological waste zones, or in places transition zones near the GWC, where possible pay exists, with high Sw and low measured resistivity (LRP), but with the additional risk of mobile water. Very broadly, the Lower Safa reservoirs can be considered to compose a "Core Area" with optimum reservoir development, both in terms of thickness and porosity, and a "Flank Area", with more marginal facies. The orientation of these differs between the LS1-3 and LS5 packages, and is inferred to result from a change from confined estuarine sand bodies in the lower unit to a less constrained deltaic complex in the upper. GaffneyCline has confirmed these interpretations based on porosity-height mapping (Figure 5).

Figure 4: Lower Safa Formation, Representative Reservoir Section



Source: GaffneyCline from vPDR database

Figure 5: Obaiyed Field. Lower Safa Formation Core Reservoir Area



Source: GaffneyCline from vPDR database

Unlike the Lower Safa, the Upper Safa is composed of thin discrete sandstone layers, which are laterally separate, and are interpreted to have been deposited in NE-SW trending tidal sand bars, subparallel to the axis of the Matruh Trough.

1.2.1.3 Reservoir and Fluid Properties

The pressure data provided mostly consist of MDT measurements that indicate the reservoirs have normal pressure and temperature gradients (Table 7). Obaiyed is a wet gas field and the condensate-gas ratio (CGR) for Obaiyed is generally approximately 30-50 scf/Bbl, but CGR can be higher, and range from an average of 38 Bbl/MMscf in the SE part of the field to 100 Bbl/MMscf (LS 5) or 144 Bbl/MMscf (LS1-3) in the NW. The dividing line between these two domains is taken as the principal NE-SW normal fault that bisects the field. Methane is 78.8 Mole % while CO_2 is seen to be 8.4 Mole % from PVT data.

No PVT data are available for the Upper Safa formation. Here, CGR is assumed high throughout from test and production data, and a value of 120 Bbl/MMscf is used in evaluation.

Table 7: Obaiyed: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Obaiyed	Lower Safa	3,994	149.5	5,900	5,361	0.0042	30-50	0.01	0.73

1.2.1.4 Production Facilities

The Obaiyed area fluids are transported via pipelines for treatment in the Obaiyed processing plant. The facility takes its feedstock from the Obaiyed, North Um Baraka (NUMB) and Khalda Qasr (3rd party gas) producing fields. The processing plant has two main processing trains and has the potential to process 420 MMscfd of gas and 16 Mbpd of condensate. The facility separates and then compresses the lower pressure feedstocks from Obaiyed and NUMB fields, which are co-mingled with Khalda Qasr gas before entering the main process trains.

Each processing train at the Obaiyed processing plant is designed to separate the liquid (condensate and water), treat the gas to remove CO_2, dehydrate and extract NGLs to ensure the export gas is of sales quality. Produced water is treated and then reinjected into a well. The treated gas from Obaiyed is exported via a booster compression station before export into the EPC gas distribution network. Condensate is stabilised and exported to Meleiha before being forwarded to the Hamra Terminal for offtake by tanker.

After December 2020, the Khalda Qasr gas supply to Obaiyed processing plant will cease. When developed, it is planned that the North Matruh (NM), NUMB and North East Obaiyed (NEO - which is not part of the acquisition) fluids will feed into the Obaiyed facility to fill any ullage.

1.2.2 HIIP

GaffneyCline has reviewed GIIP estimates presented by the Vendor and the static model database for the Lower Safa Formation provide as part of the vPDR. Some independent estimates and cross-checks have also been made.

GaffneyCline checked the petrophysical interpretations made by the vendor by making an independent analysis of data available for three wells D-10, D-34 and D-45. This generally validated the vendor analyses and gave confidence in the petrophysical inputs to the static model and the targets identified for recompletions.

Estimates of the GIIP are shown in Table 8. The salient points are:

- For the Lower Safa Formation, GaffneyCline has conducted sufficient volume checks to be satisfied that the volumes represented by the vendor static model are valid as a Best Case;
- Volumes derived from dynamic modelling do not include all of the mapped volume, but are included to illustrate the range of uncertainty present;
- The static model volumes do not include any "lean" facies; and
- Upper Safa volumes estimated approximately by GaffneyCline are only those in the pools believed to be accessible by planned activities, not all of the gas contained in other, unconnected pools.

Table 8: GIIP, Obaiyed Field

<table>
<tr><th rowspan="2">Reservoir</th><th rowspan="2">Source</th><th></th><th colspan="3">GIIP (Bscf)</th><th></th></tr>
<tr><th></th><th>Low</th><th>Best</th><th>High</th><th>Notes</th></tr>
<tr><td rowspan="4">Lower Safa</td><td>FDP 2016</td><td>Total</td><td>2,690</td><td>3,140</td><td>3,650</td><td>Based on dynamic model</td></tr>
<tr><td rowspan="3">PETREL calculation in VDR</td><td>LS 1-3</td><td>-</td><td>2,457</td><td>-</td><td>Includes some volume in LS 0 unit</td></tr>
<tr><td>LS 5</td><td>-</td><td>1,191</td><td>-</td><td></td></tr>
<tr><td>Total</td><td>-</td><td>3,648</td><td>-</td><td>Volumes do not include any gas in high Sw “lean” facies</td></tr>
<tr><td rowspan="2">Upper Safa</td><td>Vendor FDP 2013</td><td>Total</td><td>146</td><td>180</td><td>210</td><td>Understood to be total volume</td></tr>
<tr><td>GaffneyCline Estimate</td><td>Total</td><td>-</td><td>86</td><td>-</td><td>GaffneyCline approximate estimate of GIIP in pools associated with planned completion etc. activities</td></tr>
</table>

Source: Vendor VDR, vPDR and GaffneyCline estimates

In addition, GaffneyCline has used the static model volumes to estimate the Best Case GIIP in the core, and western and eastern flanks of the field, to be targeted by the future development programme (Table 9).

Table 9: Obaiyed Field GIIP in Lower Safa Formation in “Flank” Areas of Field

Area	GIIP (Bscf) Best
Core	**2,826**
Western Flank	697
NW Flank LS1-3	*328*
NW Flank LS 5	*164*
SW Flank LS 5	*205*
Eastern Flank	125
(Total flank)	***(822)***
Total Field	**3,648**

1.2.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline’s evaluation are listed in Table 10.

Table 10: Obaiyed: Resources Described in Databooks

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NFA	Existing wells NFA		**Reserves**
Lower Safa Infill	Lower Safa Core infill	Defined well locations in core of field	**Reserves:** 12 vertical and horizontal well locations defined.
	Lower Safa flanks	Defined well locations in flanks, with more marginal reservoir quality	
	Lower Safa Upsides	Notional well locations in vendor plan, principally in flanks of field	**Contingent Resources,** 22 notional locations are considered CR based on the drilling schedule and the lack of a defined plan to exploit marginal reservoir facies.
Upper Safa Infill	Upper Safa Infill	Recompletion and fracking programme in existing wells	**Reserves:** 8 activities defined, and a further 12, contributing to **Contingent Resources** are included, to be selected from other available targets.
General infill	LLP	Benefit to vendor of introduction of Low Line Pressure	**Reserves**
N/A (WOs added by Consortium)	Reactivation of shut-in wells	Also treated as additional infill project contributing to Reserves	**Reserves**

1.2.4 Historical Field Performance

Obaiyed production commenced in August 1999 and it currently comprises production of gas and condensate, with very small amounts of water.

Gas production reached a peak of some 336 MMscfd in 2003, declining to 117 MMscfd by 2019, as the pressure has substantially declined. The Obaiyed J14 area started production in 2015 and production peaked to 88 MMscfd in 2017.

The CGR is approximately 30-50 Bbl/MMscf, with current CGR at 44 Bbl/MMscf for Obaiyed main and 50 Bbl/MMscf for Obaiyed J14 area.

The current water rate is around 984 bwpd in Obaiyed main and 330 bwpd in J14 area.

Historical field performance for Obaiyed main and the J14 area are shown in Figure 6 and Figure 7 respectively. The cumulative produced volumes, rates and water cuts are summarised in Table 11.

Figure 6: Historical Production, Obaiyed Main

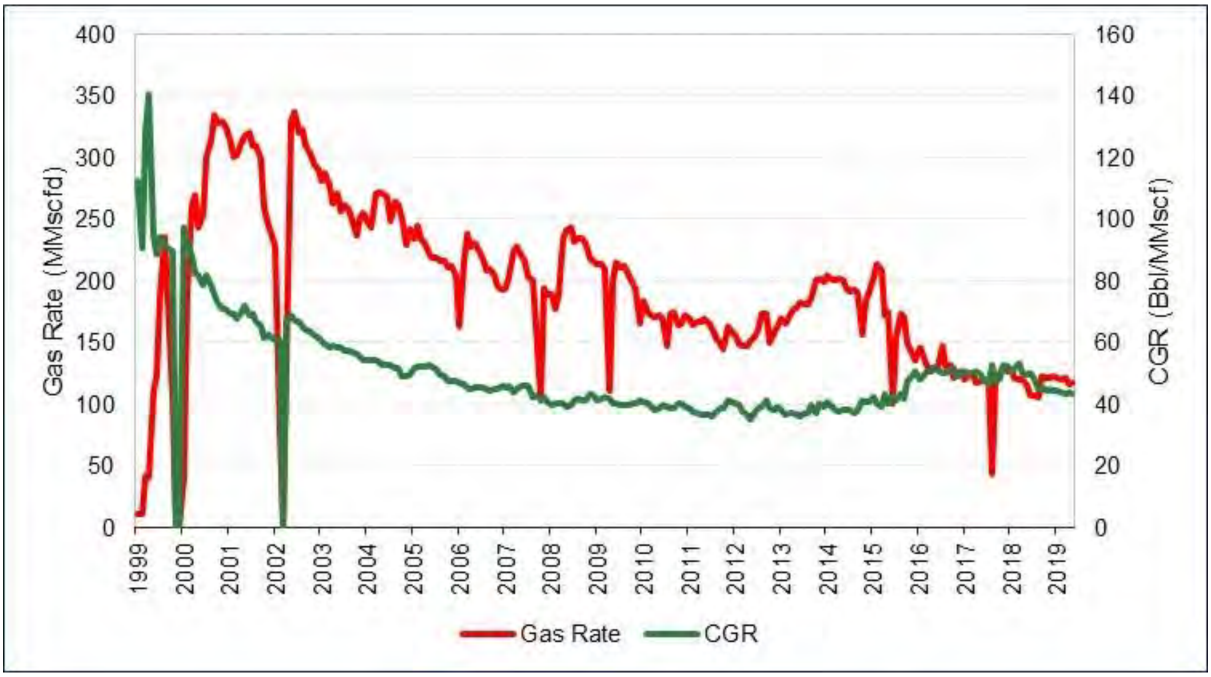


Figure 7: Historical Production, Obaiyed J14 Area

Table 11: Obaiyed Field Production Performance as at 31st December 2019

Field	Active Well Count in December 2019	Cumulative Gas Production to End 2019	Average Gas Rate in 4Q 2019	Average Condensate Rate in 4Q 2019	Average Water Rate in 4Q 2019
	Number	Bscf	MMscfd	bcpd	bwpd
Obaiyed	36	1,423.1	118.6	5,164.5	984.5
J14	7	89.2	42.3	807.3	329.5
Total	**43**	**1,512.3**	**160.9**	**5,971.7**	**1,314.0**

1.2.5 Field Development Plan

The consortium's five year future development plan for the fields includes the following activities:

- Infill opportunities in the Lower Safa core area: continued drilling primarily in the Lower Safa in order to produce from currently un-drained areas that have been identified by the Vendor, and audited by GaffneyCline. These include five Core well locations.
- Lower Safa Flank Development: Developing poorly drained areas by long horizontal multi-fracced wells. These include seven flank wells and one workover for well H22, which has well integrity issues.
- Re-completions and fracs targeting eight upper Safa sands across the Core development area. These comprise eight recompletions and fracs in existing lower Safa wells.
- Low Line Pressure project: lowering the pre-compression inlet pressure to 6 bar.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The new production wells and well workovers are summarised in Table 12 and Table 13 respectively.

Table 12: Obaiyed Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Lower Safa	0	2	3	3	4	**12**
Upper Safa	0	0	0	0	0	**0**
Total	**0**	**2**	**3**	**3**	**4**	**12**

Table 13: Obaiyed Workover Schedule

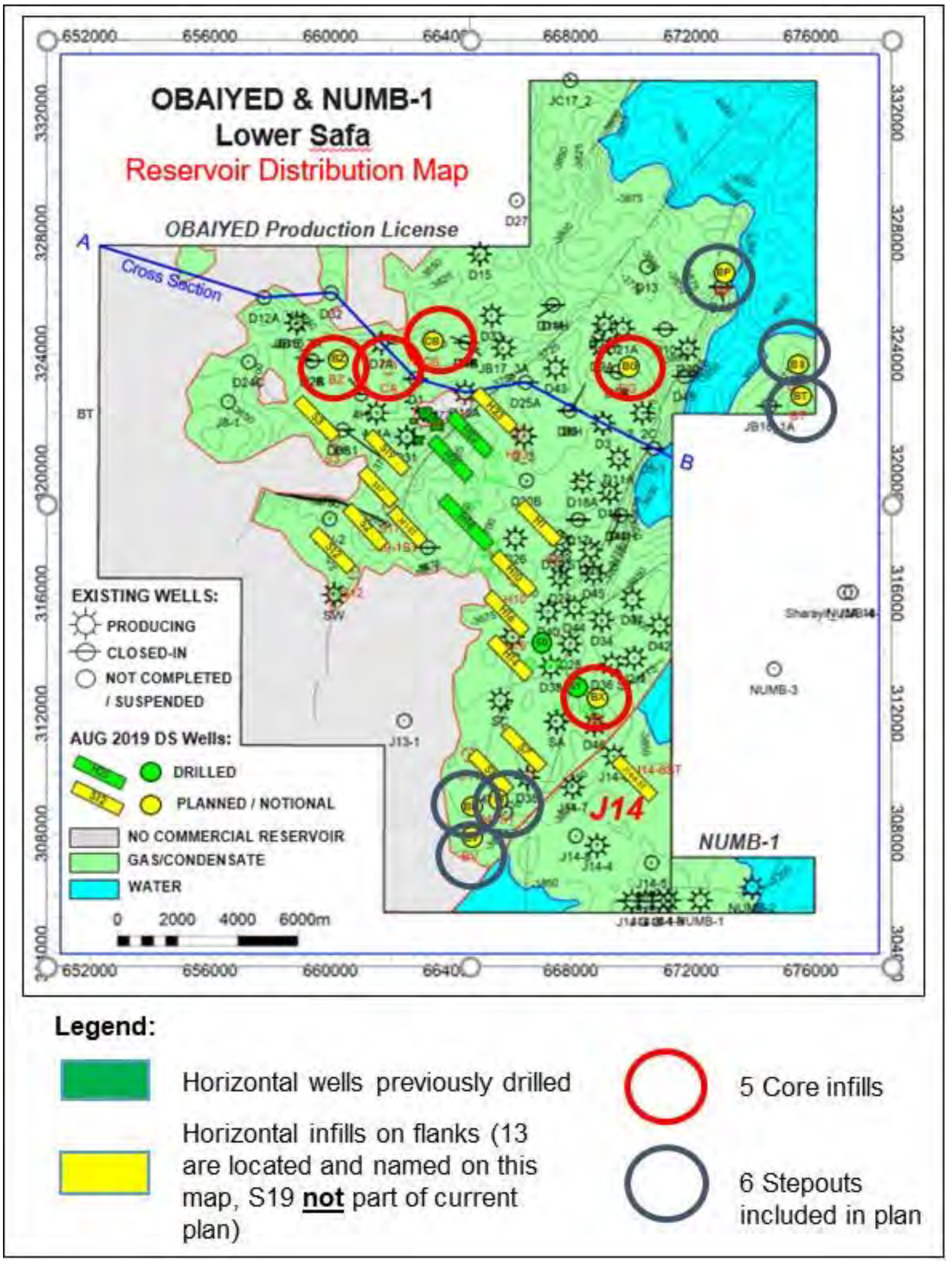
Year	2020	2021	2022	2023	2024	Total
Lower Safa	0	1	0	0	0	**1**
Upper Safa	0	7	1	2	2	**12**
Total	**0**	**8**	**1**	**2**	**2**	**13**

Further details of the new locations contributing to the work programme are discussed below.

Lower Safa Formation

Discussions with the vendor during the vPDR confirmed that their overall plan consists of a programme of 24 defined locations, including horizontal wells in the more marginal western flank area, vertical wells within the field core, and "stepouts" to further assess the eastern and northern flanks of the field, both in terms of reservoir development, and in terms of assessing the position of the GWC. Locations are shown in Figure 8. In addition, there is provision for a further ten wells, whose locations are not yet defined in detail, making a total of 34 future wells.

Figure 8: Lower Safa Formation, Future Development Locations



Source: Vendor VDR

GaffneyCline has reviewed these locations and graded their attractiveness in terms of the principal geological risks anticipated. These are:

- Definition of location within dataset;
- Horizontal/vertical well;
- Proximity to core area, based on porosity and net reservoir thickness;
- Proximity to GWC in NE of field; and
- Likelihood of encountering "Lean" facies at base of each reservoir – high water saturation in transition zone or associated with clay-bound water.

Results of the ranking of locations are described in Table 14.

Table 14: Obaiyed Field. Assessment of Planned Lower Safa Infill Locations

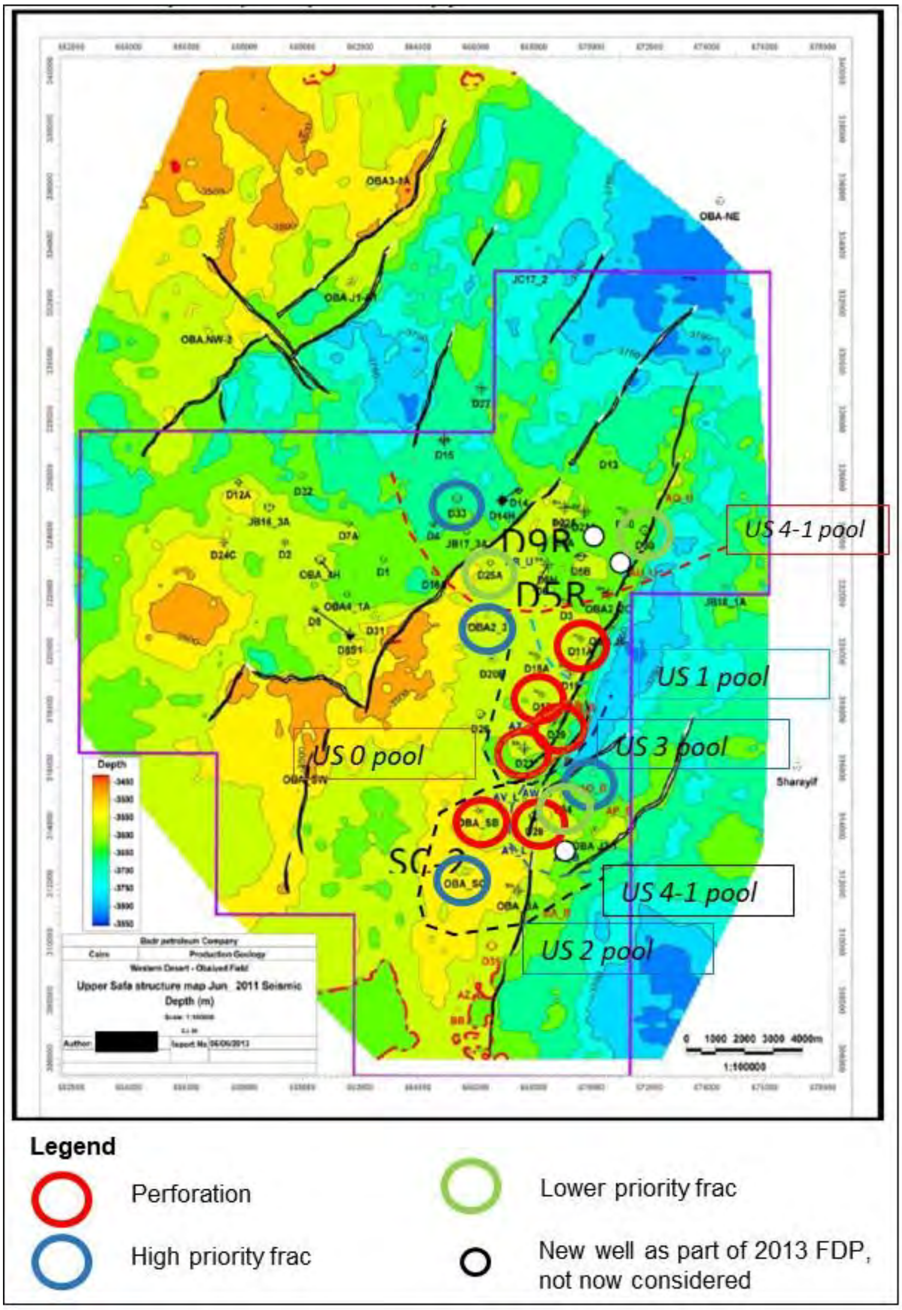
Cluster	Location	Well	Principal Reservoir	Ranking
J-14	J-14-6ST	Horiz	LS-3, LS-5	High
Core (north)	BZ	Vert	LS1-3	Moderate
Core (north)	CB	Vert	LS1-3	Moderate
Core (north)	CA	Vert	LS1-3	Moderate
Core (North)	BG	Vert	LS1-3	Moderate
Core (Southeast)	BX	Vert	LS-5	Moderate
SW Flank	S11	Horiz	LS-5	Moderate
SW Flank	S7	Horiz	LS-5	Moderate
SW Flank	H-1	Horiz	LS-5	High
SW Flank	H-10	Horiz	LS-5	High
SW Flank	H-16	Horiz	LS-5	High
SW Flank	H-14	Horiz	LS-5	Moderate
SW Flank	H23	Horiz	LS-5	High
NW Flank	S3	Horiz	LS1-3	Moderate
NW Flank	S17	Horiz	LS-5	Moderate
NW Flank	S2	Horiz	LS-5	Moderate
NW Flank	S12	Horiz	LS-5	Low
NW Flank	J9-1ST	Horiz	LS-5	Moderate
Northeast	BP	Vert	LS-3, LS-5	Low
East	BS	Vert	LS-1-2	Low
East	BT	Vert	LS-1-3	Low
SW Flank	47-ST	Vert	LS-5	Low
SW Flank	BU	Vert	LS-5	Low
SW Flank	BV	Vert	LS-5	Low

As noted earlier in the report, only 5 core locations (BZ, CB, CA, BG, BX), and 7 flank wells are included in the Consortium's 5 year plan. The latter would be expected to be selected from the locations graded "high" or "moderate" in the above analysis. Other locations represent future upside possibilities.

Upper Safa Formation

In its current “infill” plans, the Consortium proposes a campaign of 20 recompletions and fracking of existing completions to exploit the Upper Safa Formation (Figure 9). Production to date has been small. Although new well locations are discussed in the original 2013 FDP, these are not understood to be part of the Vendor’s current plan and hence, not part of the Consortium’s plan. The Consortium’s plan highlights 12 opportunities that would be initially targeted, notionally from those flagged as “good” and “moderate” in the succeeding analysis.

Figure 9: Upper Safa Formation, Future Development Locations



Source: Vendor VDR

GaffneyCline has examined the detail of the activities planned and notes that the bulk of the resources are aimed at two main sand bodies, the Upper Safa 4-1 sand in the north, and the Upper Safa 2 sand in the south. Approximate estimates of GIIP for each of the sand units suggests that the incremental RF expected to be achieved ranges between 26-36%. Higher values are expected where a particular pool is targeted by activities in several wells.

The main risks are associated with the marginal reservoir quality and the performance of the frac, where this is planned. In general, however, GaffneyCline has been able to confirm the validity of the targets proposed (Table 15).

Table 15: Obaiyed Field. Assessment of Planned Upper Safa Recompletions

Sandstone unit	Well	Type of activity	Estimated CGR (Bbl/MMscf)	GaffneyCline Ranking/Comment
US0	D29	Perf	>100	Moderate
	D11	Perf	>100	Good
	D23	Perf	>100	Poor
US1 north	OBA 2-3	Frac	80-90	No well information
US1 south	SC	Frac	90-100	Good. Open completion
US2 south	SB	Perf	>100	Poor
	SC	Frac	80-90	Good. Open completion
	D37	Frac	90-100	Location and pool ID tentative. Open completion
	D34	Frac	80-90	Good. Open completion
US 3 north	D30	Frac	<80	D30 already marked as open in US4-1. US3 looks like very minimal target. Poor.
US3 south	D17	Perf	>100	Good
US4-1 north	D33	Frac	90-100	No open completion shown
	D25	Frac	<80	Good. Open completion
US4-1 south	D28	Perf	>100	Moderate
US4-2 north	D25	Frac	<80	Good. Open completion

1.2.6 Production Forecasts

For the profiles contributing to the Reserves cases, GaffneyCline carried out its own analysis based on historical well performance and analogues, using a combination of Decline Curve Analysis (DCA) for existing wells and analogue type wells to estimate the performance of the planned new wells and workovers.

The predicted technical recovery factors (to end of the licence, with no consideration of any economic cut-off) in the Lower Safa reservoir are approximately 71% for the Core area, which has most of the current producing wells and possess good reservoir properties, and 38% for the Western Flank area, taking into account the tight reservoir and the need for long reaching hydraulically fractured wells to recover the volumes.

The remaining recoverable gas and condensate volumes are shown in Table 16 and Table 17.

Table 16: Remaining Technically Recoverable Gas Volumes by Case, Obaiyed as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
NFA	280.8	305.6	329.1
Infill LS Core	17.6	35.7	54.1
Infill LS Flanks	54.9	68.2	81.1
Infill US	24.7	30.9	37.1
LLP project	7.9	9.6	11.3
SI wells Re-activation	23.9	25.2	26.5
Total	409.8	475.3	539.3

Notes:

1. The volumes in this table are to the end of August 2029; no economic cut off has been applied.
2. The volumes are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 17: Remaining Technically Recoverable Condensate Volumes by Case, Obaiyed as at 31st December 2019

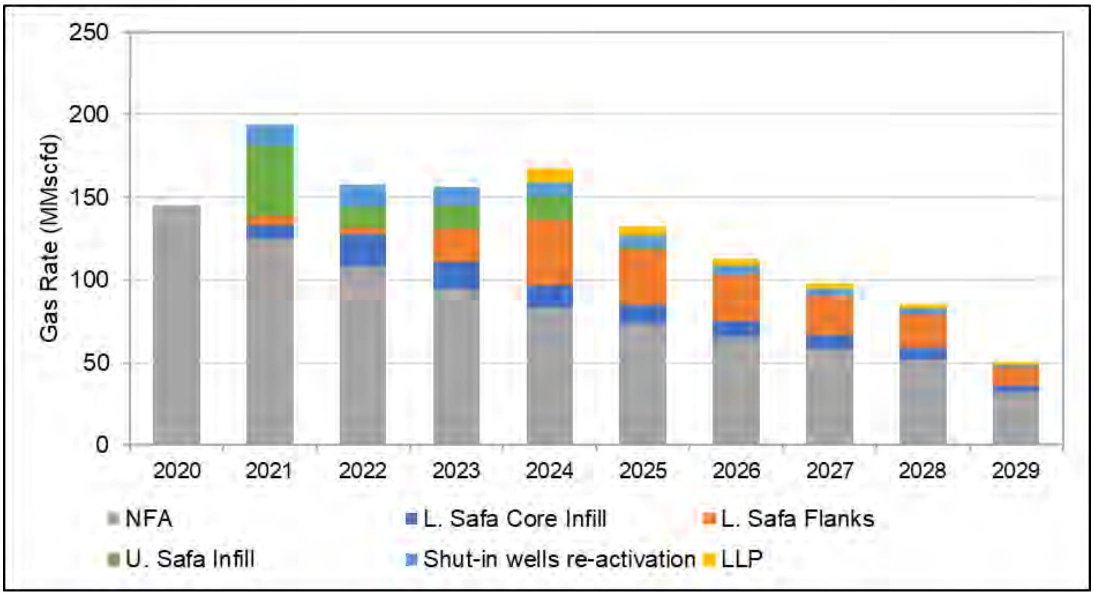
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NFA	10.1	11.4	12.3
Infill LS Core	0.9	1.6	2.4
Infill LS Flanks	2.4	3.1	3.9
Infill US	2.5	4.6	6.6
LLP project	0.3	0.4	0.5
SI wells Re-activation	0.9	1.0	1.0
Total	**17.1**	**22.2**	**26.8**

Notes:

1. The volumes in this table are to the end of August 2029; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 10 and Figure 11 show the Best Case gas and condensate forecasts for Obaiyed by activity wedge.

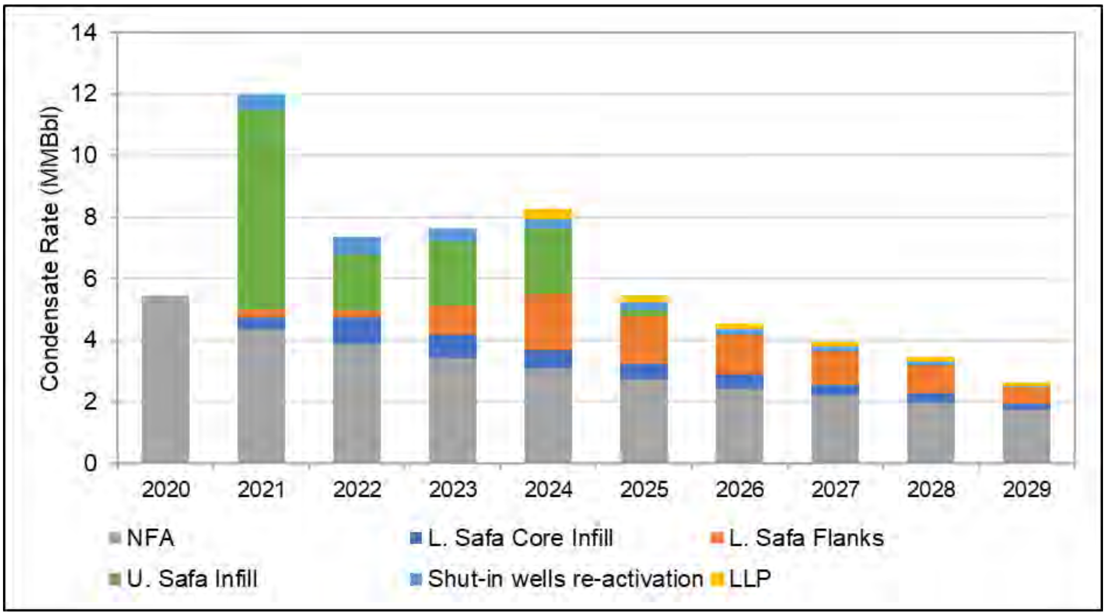
Figure 10: Best Case Gas Production Forecast, Obaiyed



Notes:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 11: Best Case Condensate Production Forecast, Obaiyed

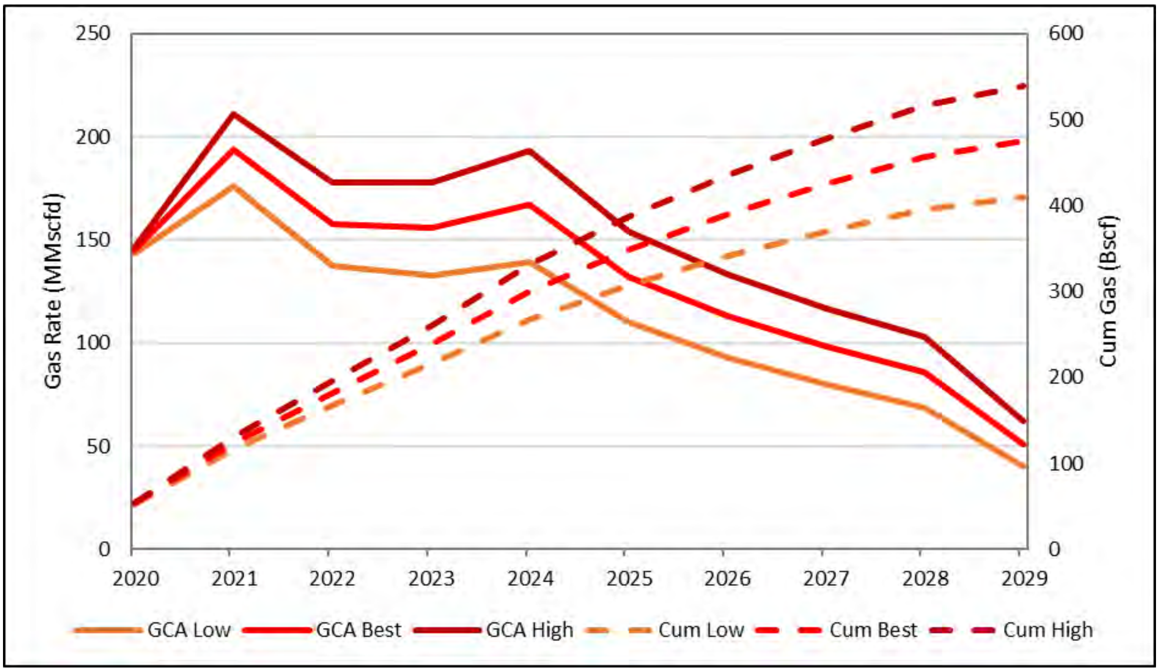


Note:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.

Figure 12 and Figure 13 show the Low, Best and High gas and condensate production forecasts for Obaiyed.

Figure 12: Gas Production Forecasts, Obaiyed

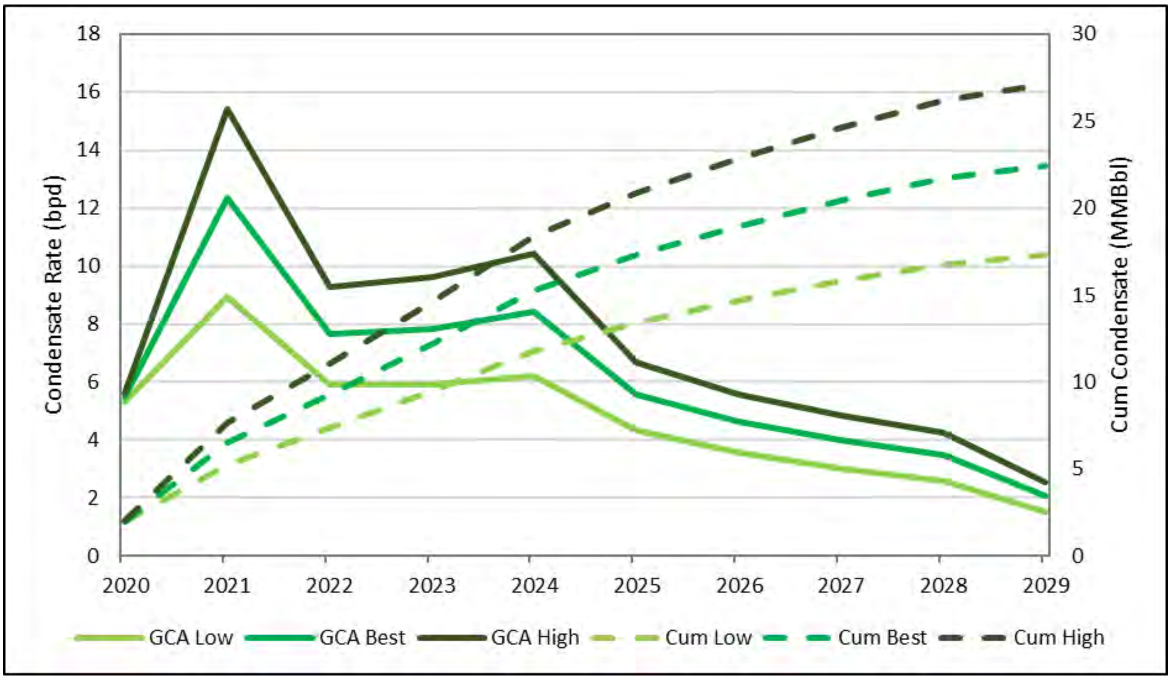


Notes:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.

2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 13: Condensate Production Forecasts, Obaiyed



Note:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.

1.2.7 Contingent Resources

Contingent Resources were assigned to well locations where low ranking was applied, or which have not yet been fully defined. Further modelling work is required to bring these opportunities to a higher level of confidence. There are seventeen upside (low ranking) locations in this category.

Activities currently envisaged more than 5 years in the future (2025 onwards) were also considered as Contingent Resources. These comprise an additional six infill wells in the Lower Safa (LS), plus twelve re-completions in the Upper Safa (US) formation. Table 18 and Table 19 show the gross gas and condensate Contingent Resources.

Table 18: Gross Gas Contingent Resources, Obaiyed, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Lower Safa	56.2	85.6	116.0
Upper Safa	16.4	20.4	24.5
Total	**72.5**	**106.1**	**150.6**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 19: Gross Condensate Contingent Resources, Obaiyed, as at 31st December 2019

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Lower Safa	2.5	3.9	5.4
Upper Safa	1.6	3.1	4.4
Total	**4.2**	**7.0**	**9.7**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

1.3 North Matruh (NM)

1.3.1 Asset Description

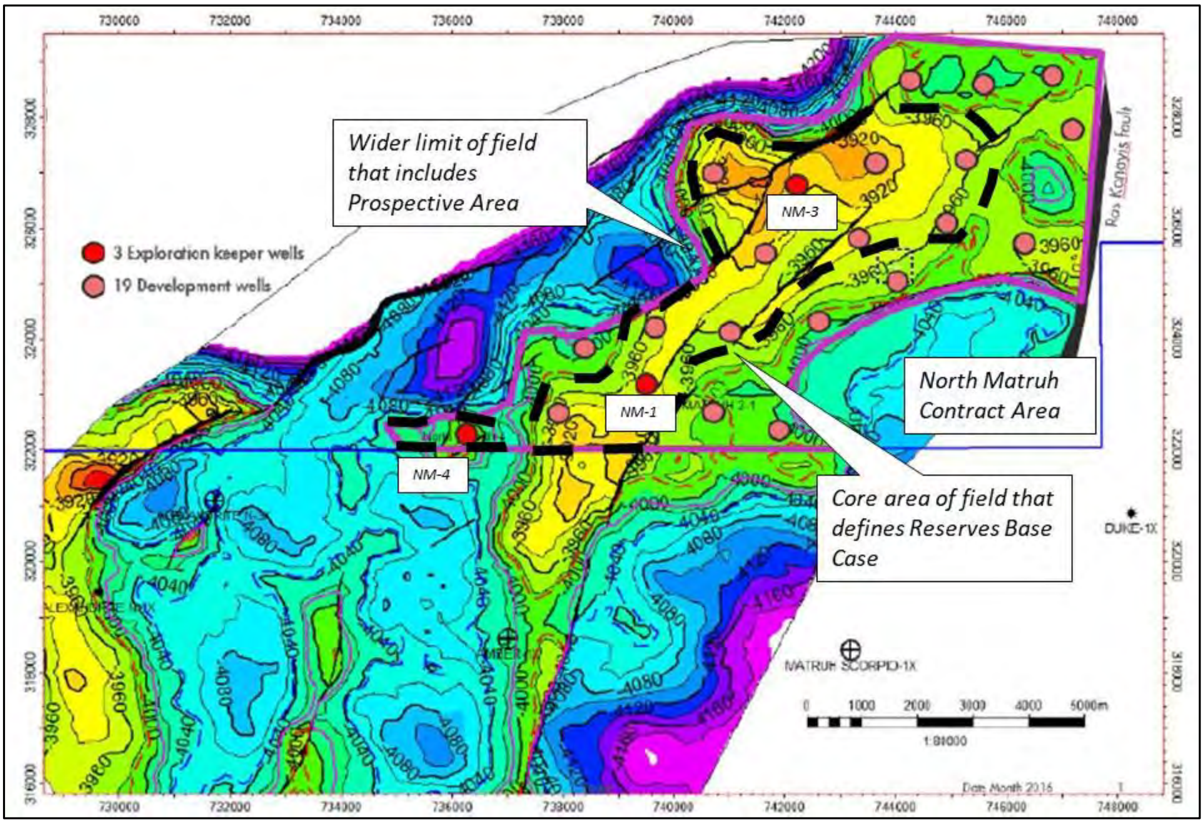
1.3.1.1 Structure/trap

The NM contract area lies on the eastern margin of the Matruh Trough. Its main asset is the Teen gas condensate Discovery, adjacent to its south central boundary, but does contain other prospects identified by the vendor.

Teen consists of a broadly ENE-WSW trending fault block, bounded to the west by a normal fault, which merges southwards with a more N-S oriented trend to the south of the contract area boundary. In detail, however it comprises a series of fault terraces, including a separate satellite to the west drilled by well NM-4, and these show evidence of fault bounded compartments leading to distinct GWC. A depth structure map on the Upper Safa is presented in Figure 14.

Gaffney Cline

Figure 14: NM (Teen) Discovery. Top Upper Safa Formation Depth Structure (m), showing Proposed Development Locations



Source: Vendor VDR with GaffneyCline annotation

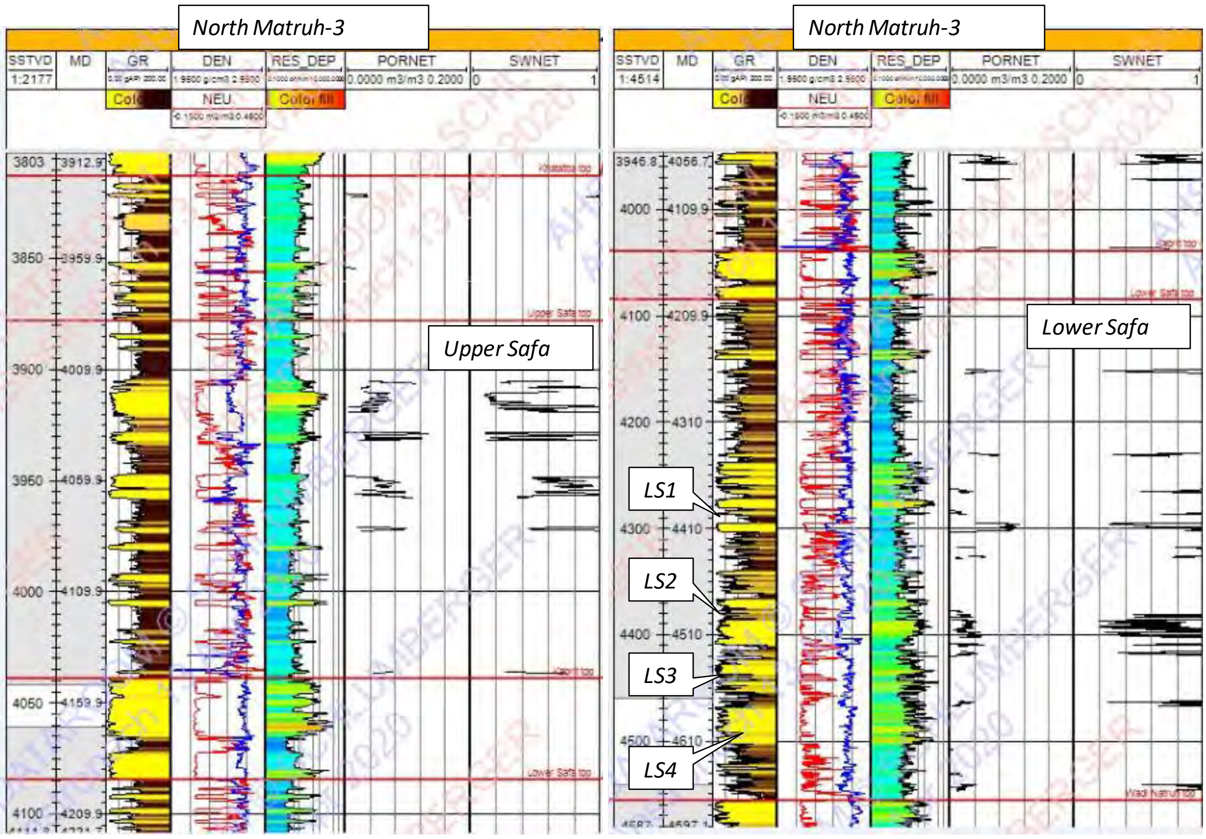
There are three wells in the NM area: NM-1, NM-3 and NM-4 (Figure 14). All are suspended as potential gas and condensate producers:

- NM-1 (Teen-1): Drilled at the southern end of the main structure and discovered gas in the Upper and Lower Safa Formation, although the former was not tested. In two tests, LS1 flowed at 9 MMscfd and LS2-5 flowed at 1.3 MMscfd. Neither unit was fracked. Gas condensate content in the Lower Safa is modest at 20-30 Bbl/MMscf.
- NM-3 (Teen North, or Teen-2): Discovered gas in both Lower and Upper Safa at the northern end of the main structure. The LS2 sand was fracked, but without significant flow. LS1 flowed at 8-18 MMscfd, without frac. A later workover was undertaken on the Upper Safa and this flowed at 9 MMscfd with significant (200 Bbl/MMscf) condensate content. There is also a small pool of oil in the Alam el Bueib Formation, although this was tight on MDT, so is likely of little significance.
- NM-4 (Teen 3): Drilled in a small satellite structure to the west. It discovered an estimated 40 m of net pay in the Lower Safa Formation and 31 m in the Upper Safa, but was not tested. It remains to be confirmed if the lower GWCs interpreted here are relevant to the wider Teen structure, or are local to this smaller feature.

1.3.1.2 Reservoir

PVT samples from NM-1 are summarized in Table 20. Test results suggest slightly higher CGR than that sampled and a value of 36 Bbl/MMscf has been used in the evaluation. Much higher condensate content (200 Bbl/MMscf) in the Upper Safa is suggested by the test at NM-3, generally in line with the variation seen at Obaiyed. A CO_2 content of around 6 mol% is indicated by the sample data. Wireline pressure data is sparse, but suggests strongly over-pressured and isolated reservoir bodies in the Upper Safa Formation at NM-4, but normal pressure gradients elsewhere and in the Lower Safa Formation.

Figure 15: NM (Teen) Discovery. Representative Reservoir Section



Source: Vendor VDR

1.3.1.3 Reservoir and Fluid Properties

PVT samples from NM-1 are summarized in Table 20. Test results suggest slightly higher CGR than that sampled and a typical value of 36 Bbl/MMscf has been used in the evaluation. Much higher condensate content in the Upper Safa is suggested by test at NM-3 of 200 Bbl/MMscf, generally in line with the variation seen at Obaiyed. A CO_2 content of around 6 mol% is indicated by the sample data. Wireline pressure data is sparse, but suggests strongly overpressured and isolated reservoir bodies in the Upper Safa Formation at NM-4, but normal pressure gradients elsewhere and in the Lower Safa Formation.

Table 20: Teen: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Teen	Lower Safa	4,306	149.2	6,596	Not known	0.0036	18	0.01	0.75

1.3.1.4 Production Facilities

Gas production is expected to be via a future trunk line to the Obaiyed gas processing facility (see section 1.2).

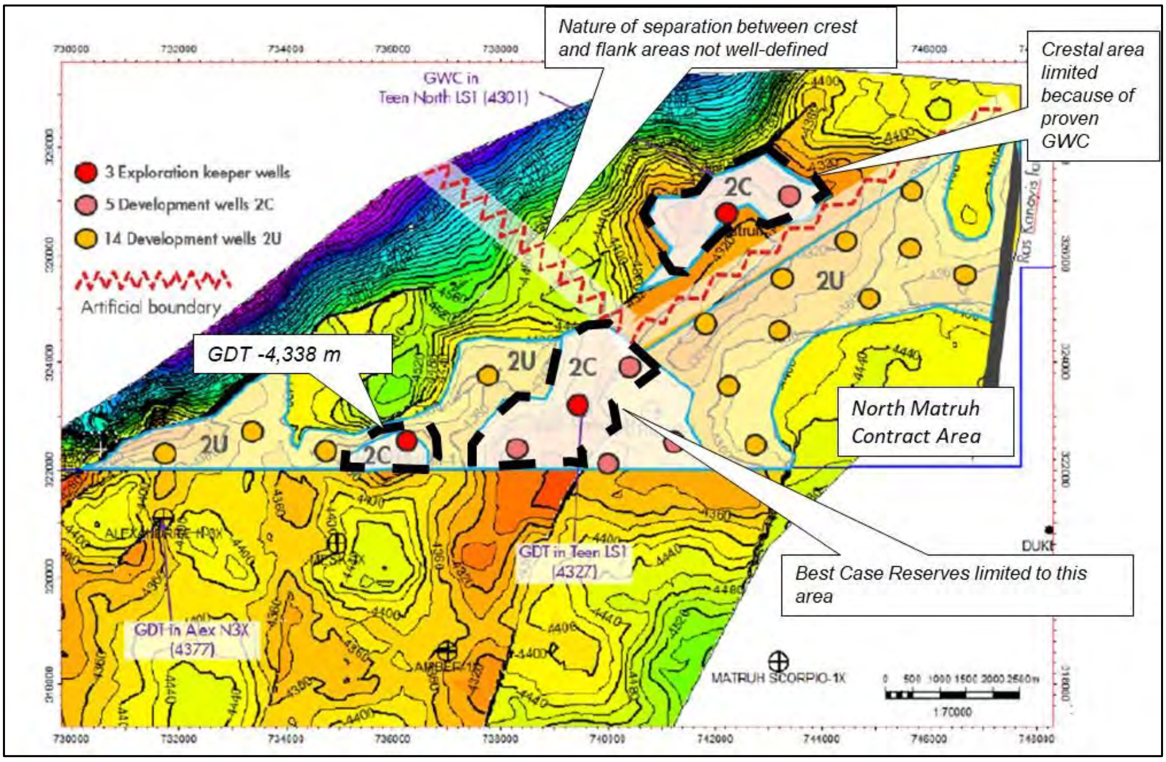
1.3.2 HIIP

HIIP is assessed from the Contingent Resources statement provided by the vendor, along with certain supporting data. There are no static models at this point to aid volumetric assessment. The vendor includes a large area of the structure in its analysis and includes volumes deemed to contribute both to Contingent Resources (i.e. discovered volumes) and to Prospective Resources (undiscovered). In its assessment, GaffneyCline has opted to focus on Best Case volumes that can realistically contribute to Reserves (Figure 14 illustrates the area for the Upper Safa, and Figure 16 for the Lower Safa). It thus specifically excludes (Figure 16):

- Volumes in the far NE of the structure near the limit of the mapping.
- Volumes below the proven GDT and below the apparent mapped spill point of the structure to the south.
- Volumes in fault terraces to the east below the GWC seen in the Lower Safa Formation at NM-3.
- Volumes in the vicinity of and below the legacy well at Mutrah 3-1 (to the east of NM-1, Figure 14), suggested to be water-bearing on test.

Differences between the GaffneyCline assessment and the vendor assessment are considered to lie in the Prospective category. HIIP are summarized in Table 21.

Figure 16: NM (Teen) Discovery. Lower Safa Formation Depth Structure and Areas included in Volume Assessment



Source: Vendor VDR with GaffneyCline annotation

Table 21: NM (Teen) Discovery. Hydrocarbons-initially-in-place

Reservoir	Source		GIIP (Bscf)			Notes
			Low	Best	High	
Upper Safa	Vendor CR Statement 2019	**Total**	**75**	**153**	**286**	
	GaffneyCline Estimate	NM-1, NM-3	-	107	-	
		NM-4	-	21	-	
		Total	**-**	**128**	-	GaffneyCline estimate broadly validates vendor estimate. Adopted in analysis as it excludes area in north east of structure
Lower Safa	Vendor FDP 2013	LS 1	43	65	83	
	GaffneyCline Estimate		-	27	-	Vendor estimate appears to overestimate 2C area
	Vendor FDP 2013	LS 2-3	102	148	198	
	GaffneyCline Estimate		-	38	-	Vendor estimate appears to overestimate 2C area, and net pay
	Vendor FDP 2013	LS 4-5	0	0	0	No resources in LS4-5 because of poor reservoir quality
	GaffneyCline Estimate		-	0	-	

Source: Vendor VDR and GaffneyCline estimates

1.3.3 Asset Streams

The categories described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 22.

Table 22: NM: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Notes
NM General	Upper Safa Development	Defined well locations in core of field	**Reserves** GaffneyCline concludes development should be considered as being limited to core areas of field only.
	Lower Safa Development	Defined well locations in core of field	
	Upper and Lower Safa eastern flank		**Prospective Resources**

1.3.4 Historical Field Performance

There is no production to date. Test results are described in section 1.3.1, above.

1.3.5 Field Development Plan

The Vendor has described a development consisting of 24 wells, including reactivation of the suspended exploration and appraisal wells and the drilling of 21 new locations. In GaffneyCline's view, it is inappropriate to consider this plan to be wholly firm as it clearly targets areas outside of the main proven areas (see Figure 14 above). Thus, only 12 well locations in the forward plan are deemed as firm and as potentially contributing to Reserves or Contingent Resources. Other proposed locations are considered as contributing only to Prospective Resources and are not considered further here, as they lie in separate structural or stratigraphic pools. In addition to the 12 previously proposed locations, efficient exploitation of the area around NM-4 is planned by the Consortium to require another well to target the Upper Safa Formation. Thus there are 13 locations in total. No grading of locations is attempted for this field.

Three of the 13 wells are the original exploration and appraisal wells, and ten are additional locations.

1.3.6 Production Forecast

The Consortium's five year future development plans for the fields thus includes the following activities:

Lower Safa:

- Three suspended gas wells in NM-1,3 and 4 plus three relatively low risk development locations, all within GDT as demonstrated at NM-1, NM-3, NM-4 and principal spill point. All six of these wells in the Lower Safa are part of the consortium's five year plan.

- Although NM-4 has not been tested, on the basis of petrophysics, MDT results and analogue with the rest of the field, it is nonetheless regarded as contributing to Reserves.
- Sixteen high risk locations, designated as outside of the vendor's 2C area (see Figure 16), are not considered as Reserves or Contingent Resources due to these wells being high risk.

Upper Safa:

- The three suspended gas wells (NM-1, NM-3 and NM-4) are not planned for early completion of the Upper Safa, so new wells will be required.
- Although NM-4 has not been tested, on the basis of petrophysics, MDT results and analogue with the rest of the field, the area around it is regarded as contributing to Upper Safa Reserves.
- Ten wells in the Upper Safa are relatively low risk development locations, within GDT as demonstrated at NM-1, NM-3 and NM-4, and the principal spill point. Locations are shown on Figure 14, to which is added a twin of the NM-4 well. All of these lie within the five year plan and are considered as contributing to reserves. Two further wells outside of the five year plan are included as Contingent Resources only (see below).
- A further ten high risk locations, located outside of the core area (see Figure 16), are not considered as contributing to Reserves or Contingent Resources.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of re-entries and new production wells are summarised in Table 23.

Table 23: NM Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Upper Safa	0	0	0	5	5	**10**
Lower Safa	0	0	0	3	3	**6**
Total	**0**	**0**	**0**	**8**	**8**	**16**

Note:

1. The first three wells targeting the Lower Safa are expected to be re-entries of the existing exploration and appraisal wells.

The remaining recoverable gas and condensate volumes are shown in Table 24 and Table 25 as of the 31st December 2019 until the end of 2047.

Table 24: Remaining Technically Recoverable Gas Volumes, NM as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
Upper Safa	30.9	54.5	101.5
Lower Safa	19.9	30.9	49.1
Total	**50.8**	**85.5**	**150.6**

Notes:

1. The volumes in this table are to the end of 2047; no economic cut off has been applied.
2. The volumes are prior to the deduction of fuel and shrinkage, estimated at 7.5% in 2020-2023 and 8% from 2023 onwards (Fuel = 4% and shrinkage due to CO_2 removal = 3.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 25: Remaining Technically Recoverable Condensate Volumes, NM as at 31st December 2019

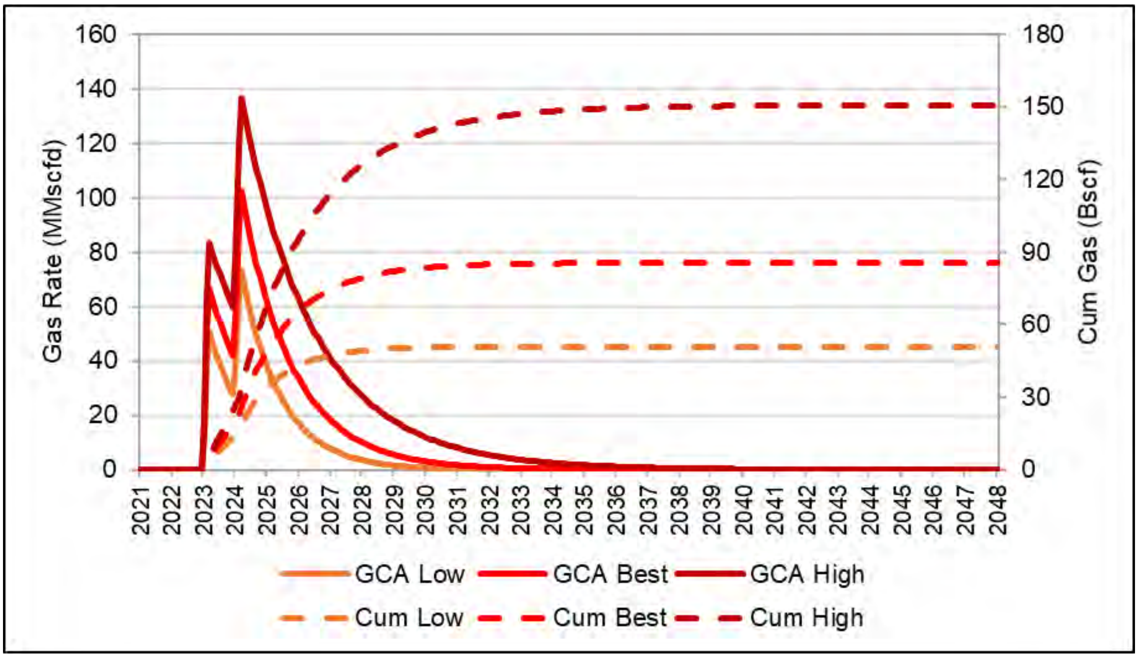
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Upper Safa	4.6	9.5	20.3
Lower Safa	0.4	0.8	1.5
Total	**5.0**	**10.3**	**21.8**

Notes:

1. The volumes in this table are to the end of 2047; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 17 and Figure 18 show Low, Best and High gas and condensate forecast production profiles for NM.

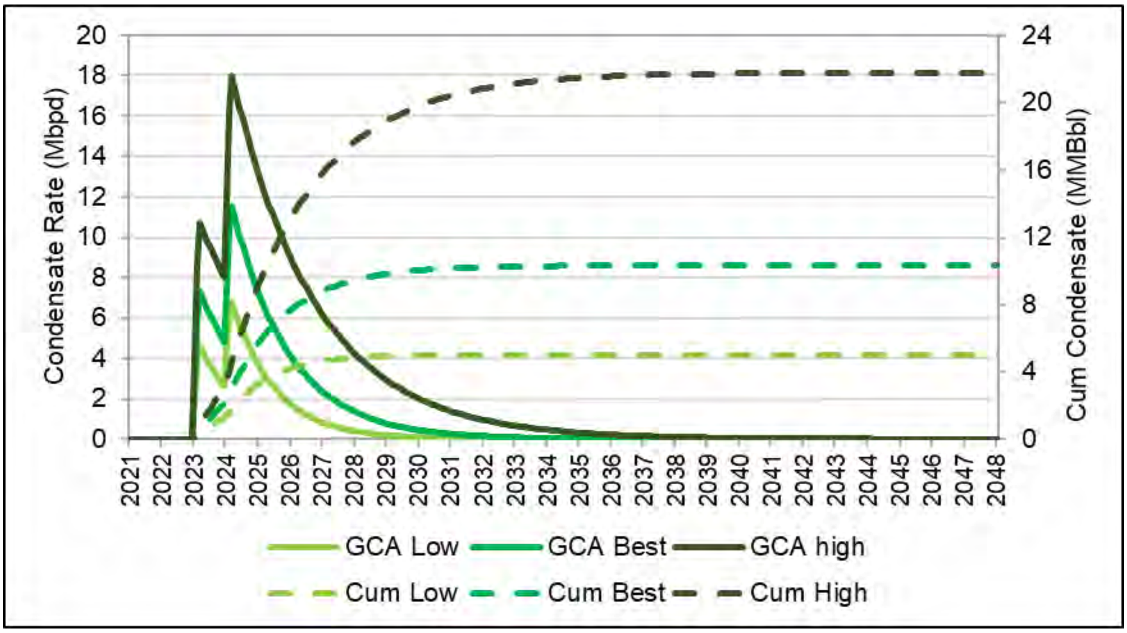
Figure 17: Gas Production Forecasts, NM



Notes:

1. The values in this figure are annual average rates; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 18: Condensate Production Forecasts, NM



Note:

1. The values in this figure are annual average rates; no economic cut off has been applied.

1.3.7 Contingent Resources

Contingent Resources were assigned to well locations which lie beyond the five-year threshold for inclusion as Reserves. Two additional infill wells in the Upper Safa starting in 2025 were thus considered as Contingent Resources, notionally located in the vicinity of the existing NM-1 and NM-3 exploration/appraisal wells. No Contingent Resources are assigned to the Lower Safa.

The Contingent Resources for gas and condensate for the Upper Safa Formation are shown in Table 26 and Table 27 respectively.

Table 26: Gross Gas Contingent Resources, NM, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Upper Safa	6.2	10.9	20.3

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.

Table 27: Gross Condensate Contingent Resources, NM, as at 31st December 2019

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Upper Safa	0.9	1.9	4.1

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.

1.4 North Umbaraka

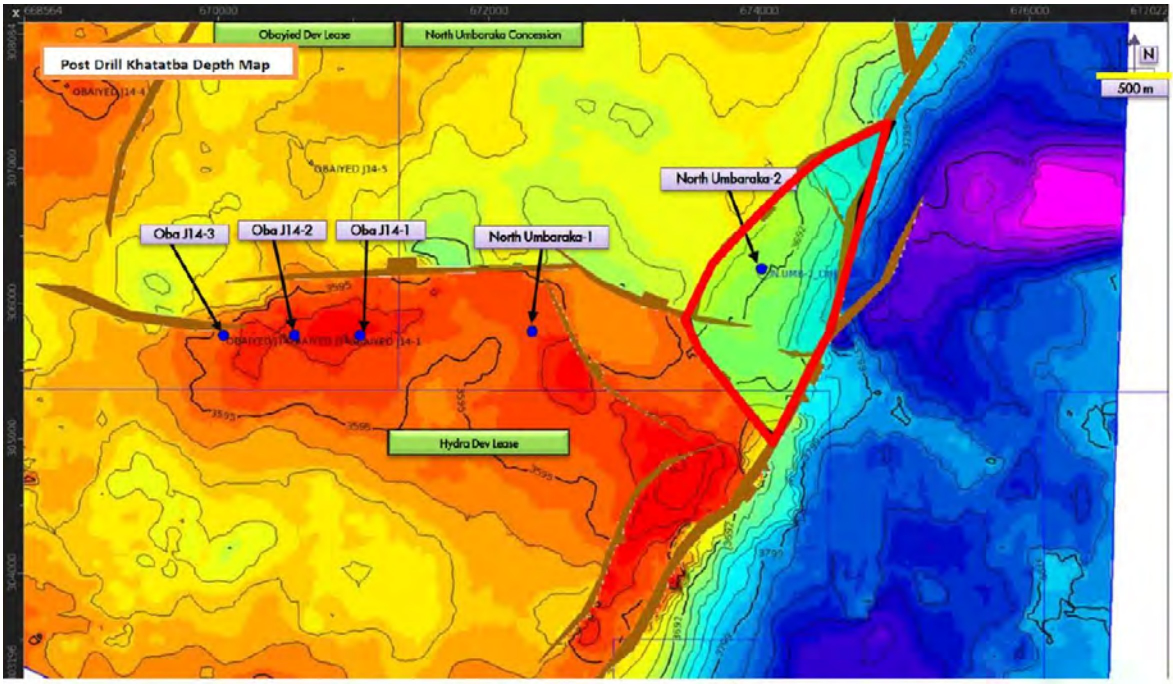
1.4.1 Asset Description

The North Umbaraka (NUMB) contract area is formed of a number of separate blocks, both to the east and west of the Obaiyed Field. It thus comprises areas which are essentially satellites to the Obaiyed Field, with a mix of Reserves and Contingent Resources, and other areas which are the realm of exploration prospects.

1.4.1.1 Structure and Trap

The proven Obaiyed satellites comprise the NUMB-1 pool, which is essentially an extension of the J-14 fault block in Obaiyed, and the NUMB-2 pool, which is a small separate downthrown fault block to the east (Figure 19).

Figure 19: NUMB-1, NUMB-2: Top Khatatba Formation, Depth Structure (m)

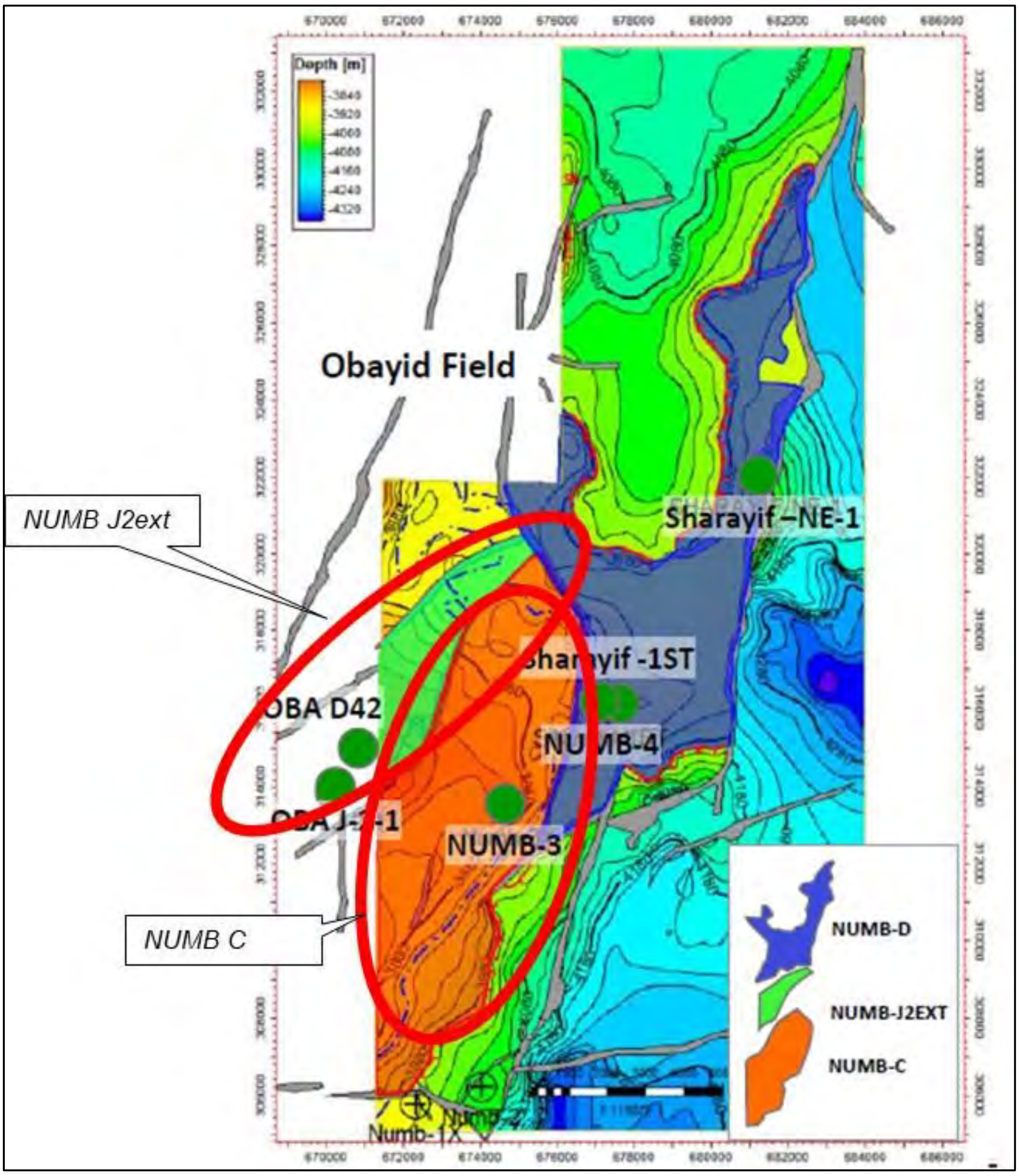


Source: Vendor VDR

To the north are two separate fault blocks, designated as NUMB-C and NUMB-J2ext (Figure 20). Both of these are designated as containing Reserves. In the case of NUMB-C, this is based on the discovery at NUMB-3, which tested up to 3.5 MMscfd from the Lower Safa Formation, and in the case of NUMB-J2ext, the area is an extension of the area proven by wells Obaiyed D-42 and J2-1.

The Consortium also proposes a further fault block to the north (NUMB-D), but this has not shown gas production to surface in three wells, and along with structural uncertainties, it has been eliminated from consideration here.

Figure 20: NUMB-C, NUMB-J2ext: Top Khatatba Formation, Depth Structure (m)



Source: Vendor VDR

1.4.1.2 Reservoir

NUMB 1 produces from both Upper and Lower Safa, but NUMB 2 only from the Upper, with the Lower being water-bearing.

The Upper Safa is shown to be tight at NUMB-3 and is not viewed as part of the reservoir fairway at J2ext.

1.4.1.3 Reservoir and Fluid Properties

PVT data are available from bottom hole samples at NUMB-2 and NUMB-3, as illustrated in Table 28. A 5.1-6.6 mol% content of CO_2 is indicated from separator gas analysis. Pressure and temperature gradients are normal.

Table 28: NUMB 2 and 3: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
NUMB 2	Upper Safa	3,844	141.9	5,974	Not known	0.0039	52	0.01	0.79
NUMB 3	Lower Safa	3,493	130.4	5,131	Not known	Not known	63	0.01	0.85

1.4.1.4 Production Facilities

Gas production is via the Obaiyed gas processing facility (see section 1.2).

1.4.2 HIIP

Analysis of HIIP of each of the fault blocks is presented by the Vendor, with modification for NUMB-C and NUMB-J2ext conducted by the Consortium. GaffneyCline has reviewed and confirmed these results and they are presented here (Table 29).

Table 29: NUMB: GIIP

Reservoir	Source		GIIP (Bscf)			Notes
			Low	Best	High	
Safa Formation	Vendor VDR	NUMB-2	6.8	9.3	12.3	Upper Safa Formation only
	Consortium	NUMB C	40.8	94.2	193.8	Upper Safa Formation only included in High Case
		NUMB J2ext	12.2	23.6	51.7	

1.4.3 Asset Streams

The categories described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 30.

Table 30: North Umbaraka Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NFA	Existing NFA	Continuing production from NUMB-2	**Reserves**
Exploration	Near Field Exploration	Pools included are only satellites to Obaiyed Field where activities are appraisal and development	**Reserves.** The separation of near field appraisal from wildcat prospect locations is key to understanding potential.
	Exploration	All other prospects in west of contract area	**Prospective Resources**

1.4.4 Historical Field Performance

The NUMB production history is from one well (NUMB-2) which was drilled in February 2018. NUMB-2 is produced through the existing Obaiyed J14 manifold and routed to the Obaiyed facilities 20 km away where the gas and condensate are processed. The production peaked at 24 MMscfd in July 2017. The well currently producing at 18 MMscfd with a CGR of 20 MMscf/Bbl as shown in Figure 21.

Figure 21: Historical Gas Production Rate and CGR for NUMB-2

1.4.5 NUMB 3 Well Test Results

A summary of the well test results from the NUMB 3 well post /pre Frack are as follows:

Pre-Frack

- Completion 4 ½ ”
- TPC Perforation Perf Interval 4,112-4,115 m and 4,118-4,127 m
- Gas Rate: 1.5-3.5 MMscfd
- WHP: 100-1,500 psi
- Water Rate <10 bpd
- Very low Condensate (CGR<1 Bbl/MMscf)

Post-Frack

- Completion 3 ½ ”
- Gas Rate: 1.5 -1.8 MMscfd
- WHP: 80-800 psi
- Water Rate: 50-150 Bbl/d
- Very Low CGR <1 Bbl/MMscf)

* Possible Frac into water, which caused an increase in water production and a reduction in gas rate

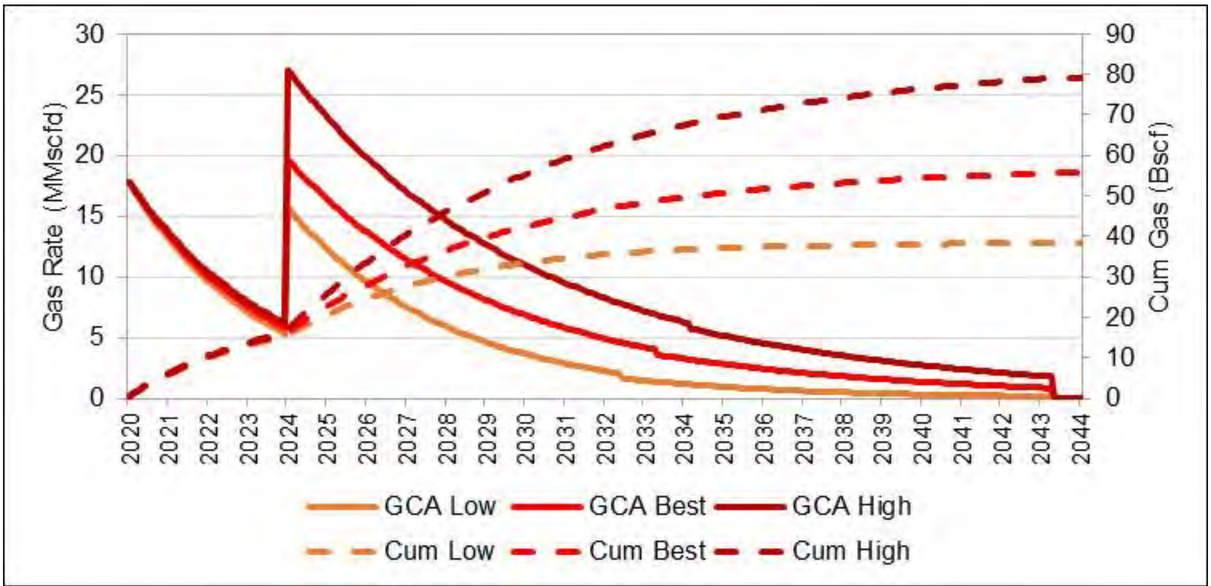
1.4.6 Field Development Plan

The Consortium's five year development plans for the field (Figure 22) includes the following activities:

* Eight Wells in the NUMB-C area.
* Two wells in the NUMB J2X area.

Figure 22 shows Low, Best and High gas forecast production profiles for NUMB.

Figure 22: NUMB Gas Production Forecasts



Notes:

1. The values in this figure are annual average rates and in 2043 include only 4 months of production (to the end of April 2043); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 4% in 2020-2023 and 4.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of new production wells are summarised in Table 31.

Table 31: NUMB Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
NUMB-C	0	0	0	5	3	**8**
NUMB J2X	**0**	0	0	2	0	**2**
Total	**0**	**0**	**0**	**7**	**3**	**10**

The remaining recoverable gas and condensate volumes are shown in Table 32 and Table 33.

Table 32: NUMB Remaining Technically Recoverable Gas Volumes, as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
NFA	21.0	22.5	23.9
NUMB-C/J2X Infill	17.4	33.1	55.2
Total	**38.4**	**55.6**	**79.1**

Notes:

1. The volumes in this table are to the end of April 2043; no economic cut off has been applied.
2. The volumes are prior to the deduction of fuel and shrinkage, estimated at 7.5% in 2020-2023 and 8% from 2023 onwards (Fuel = 4% and shrinkage due to CO_2 removal = 3.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 33: NUMB Remaining Technically Recoverable Condensate Volumes, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NFA	0.3	0.4	0.4
NUMB-C/J2X Infill	0.0	0.0	0.0
Total	**0.3**	**0.0**	**0.4**

Notes:

1. The volumes in this table are to the end of April 2043; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

1.4.7 Contingent Resources

Contingent Resources are assigned to wells where locations have not yet been defined. Further modelling work is required to bring to these opportunities to a higher level of confidence.

An additional three infill wells in the Lower Safa NUMB-C area, planned from 2025 were considered as Contingent Resources.

The gas Contingent Resources for the Lower Safa reservoir are shown in Table 34.

Table 34: Gross Contingent Gas Resources, NUMB, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Lower Safa	7.4	14.0	23.4

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2 Abu Gharadig Basin

2.1 Regional Geology

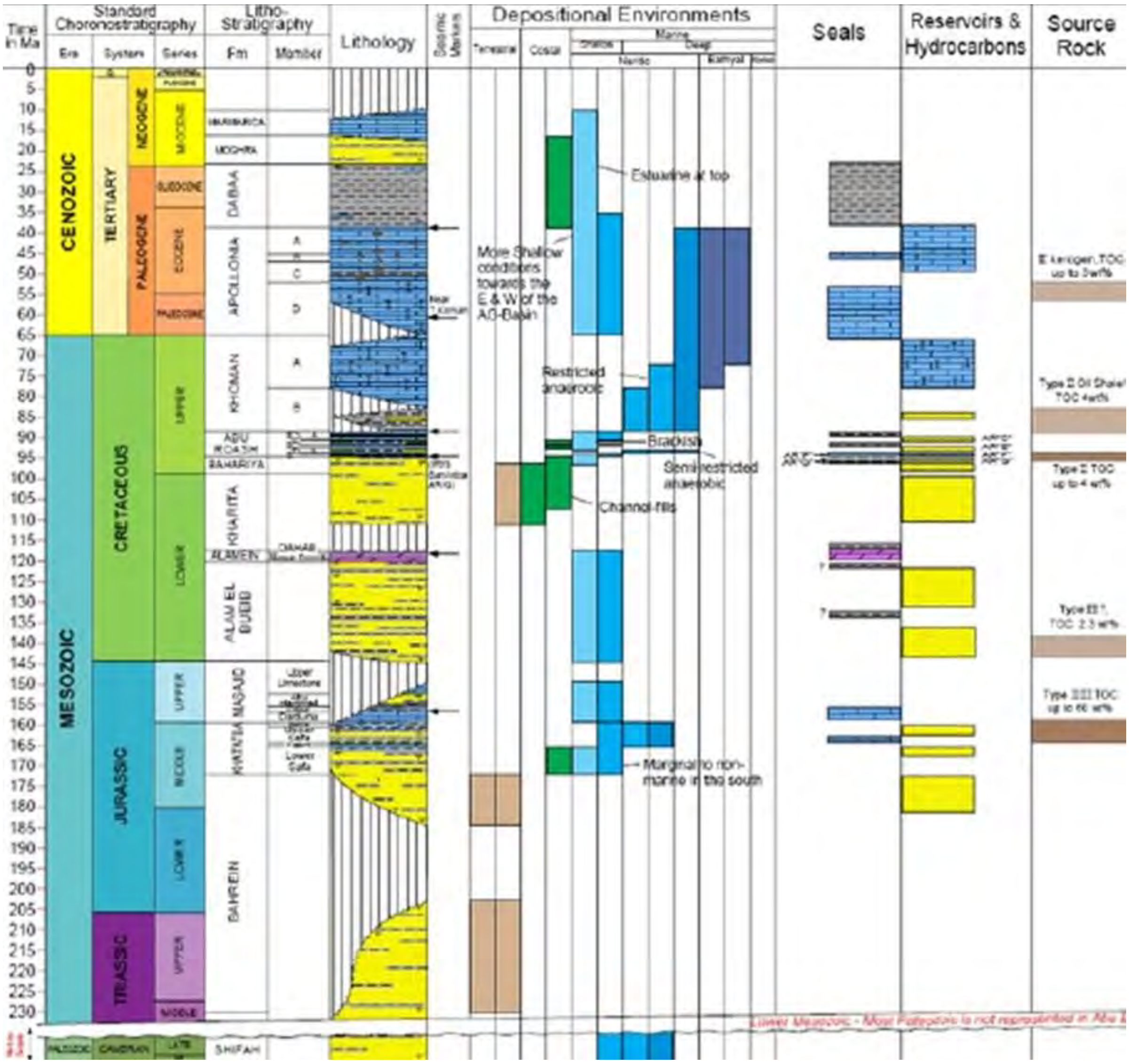
Assets in the BED, Sitra, NAES and NAEG all lie within the Abu Gharadig sedimentary basin. This forms an approximately ENE-WSW oriented depression within the platform of the Western Desert. It probably relates to an ancestral Palaeozoic basin, but owes its current form to transtensional rifting during the Triassic, Jurassic and Cretaceous. Overall the basin is controlled by approximately E-W basement faults, but the rifting has opened an extensional fabric of approximately NW-SE trending normal faulting. Rifting continued until the end of the Early Cretaceous, followed by a brief phase of passive subsidence, followed in the latest Cretaceous by a phase of inversion tectonics, created by phases of Tethyan continental convergence to the NE. From the latest Eocene to the present day, the area has seen a reversion to passive margin subsidence on the southern coast of the Mediterranean.

The overall representative stratigraphy for the area is shown in Figure 23. An initial phase of Triassic to lower Middle Jurassic sandstones represents the earliest rift phase. This was followed by carbonates in the remainder of the Middle and Upper Jurassic. Clastics dominate the Lower Cretaceous, with a mix of clastic and carbonate sedimentation in the Middle Cretaceous in the transition to post-rift phase, as a result of the complex interplay of local rifting and overall sea level. Regional carbonate sedimentation dominates the later stages of the basin's history.

Reservoirs occur principally in the sandstones of the Lower and Middle Cretaceous in the Kharita, Bahariya and Abu Roash Formations. The latter also contains some limestone reservoir interbeds. Recent discoveries have highlighted the deep potential of the Middle Jurassic Khatatba/Safa Formation sandstones and there remains other carbonate reservoir potential, deep in the Lower Cretaceous section in the Alamein Dolomite, and also in the shallow chalks of the Apollonia and Khoman Formations.

Hydrocarbon charge is complex and varies within and between each field. Sourcing is of mixed oil and gas from kitchens in the Khatatba Formation and the Abu Roash Formation, with several other subordinate source rock horizons.

Figure 23: Abu Gharadig Basin Stratigraphy



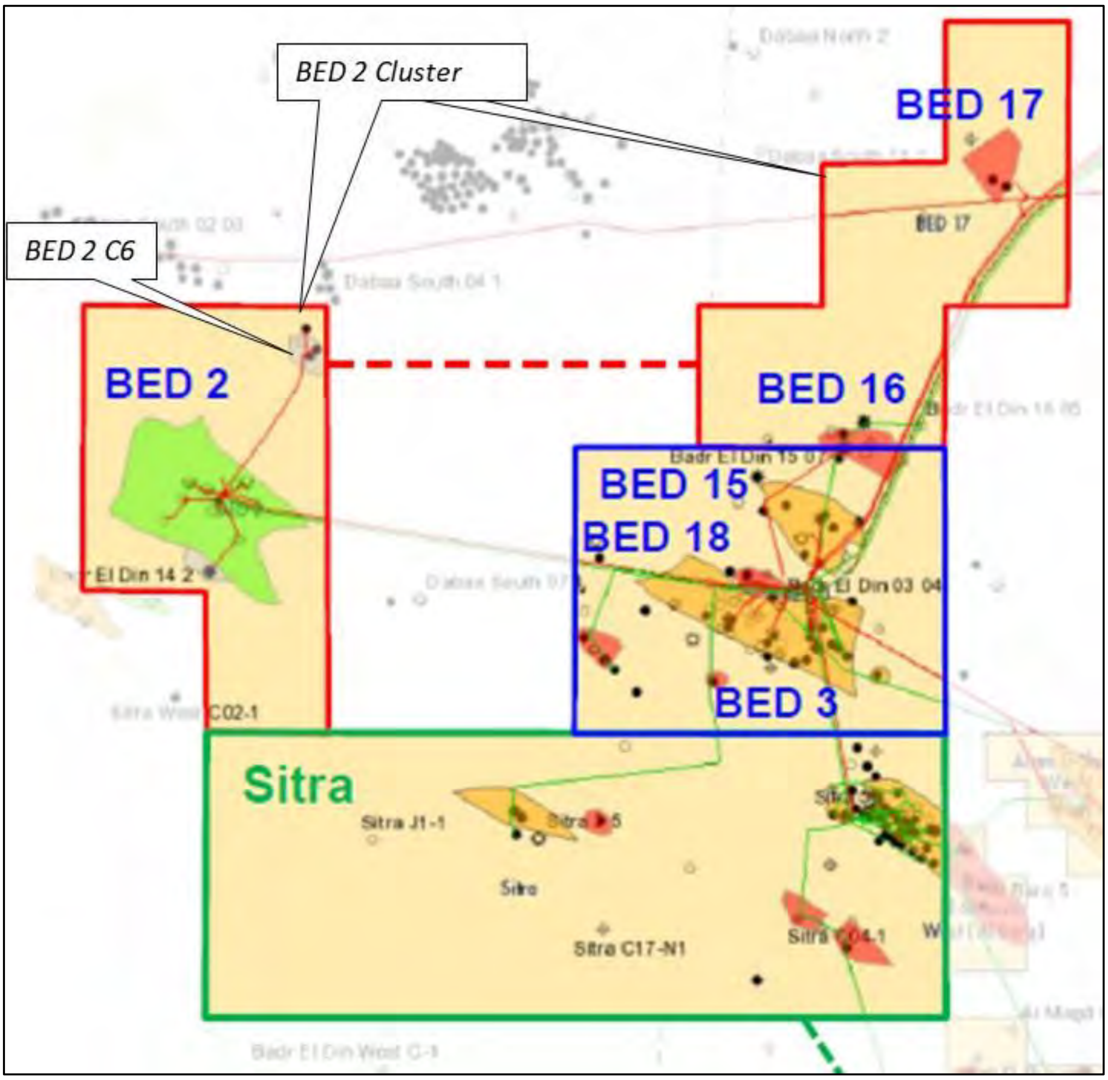
Source: Vendor VDR

2.2 BED 2 Cluster

2.2.1 Asset Description

The BED 2 cluster, as described by the vendor, consists of the BED 2, BED 16 and BED 17 development leases (Figure 24). These are considered together despite the distance of approximately 25 km between the BED 2 and BED 16 blocks.

Figure 24: BED 2 Cluster Location Map

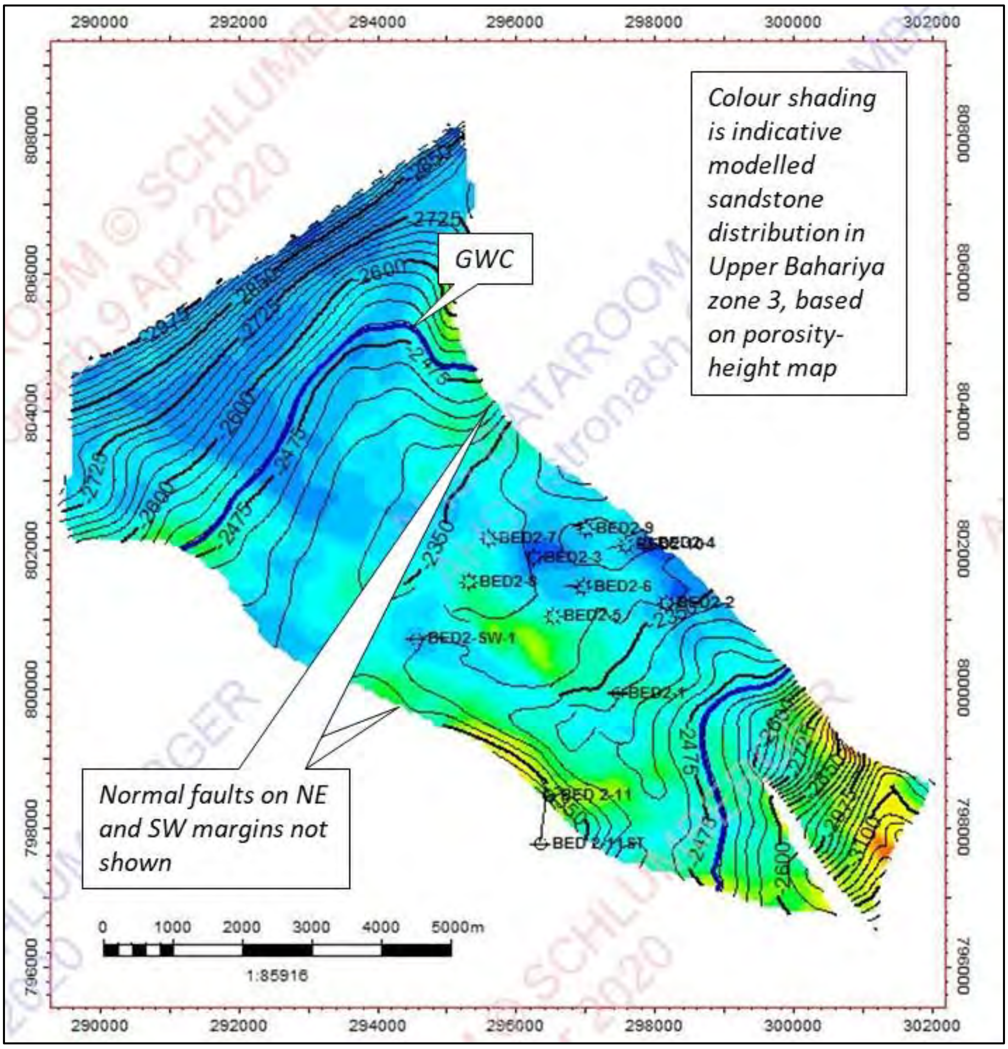


Source: Vendor VDR

2.2.1.1 *Structure and Trap*

BED 2 is a well-established gas field, It is a horst block structural trap, constrained by normal faults on SW and NE margins, but dip-closed to the NW and SE (Figure 25). Previous drilling has focused on the axial crest of the structure, but leaves flank areas poorly developed.

Figure 25: BED 2 Top Bahariya Depth Structure Map (m) and Modelled Sand Distribution Upper Bahariya 3 Zone



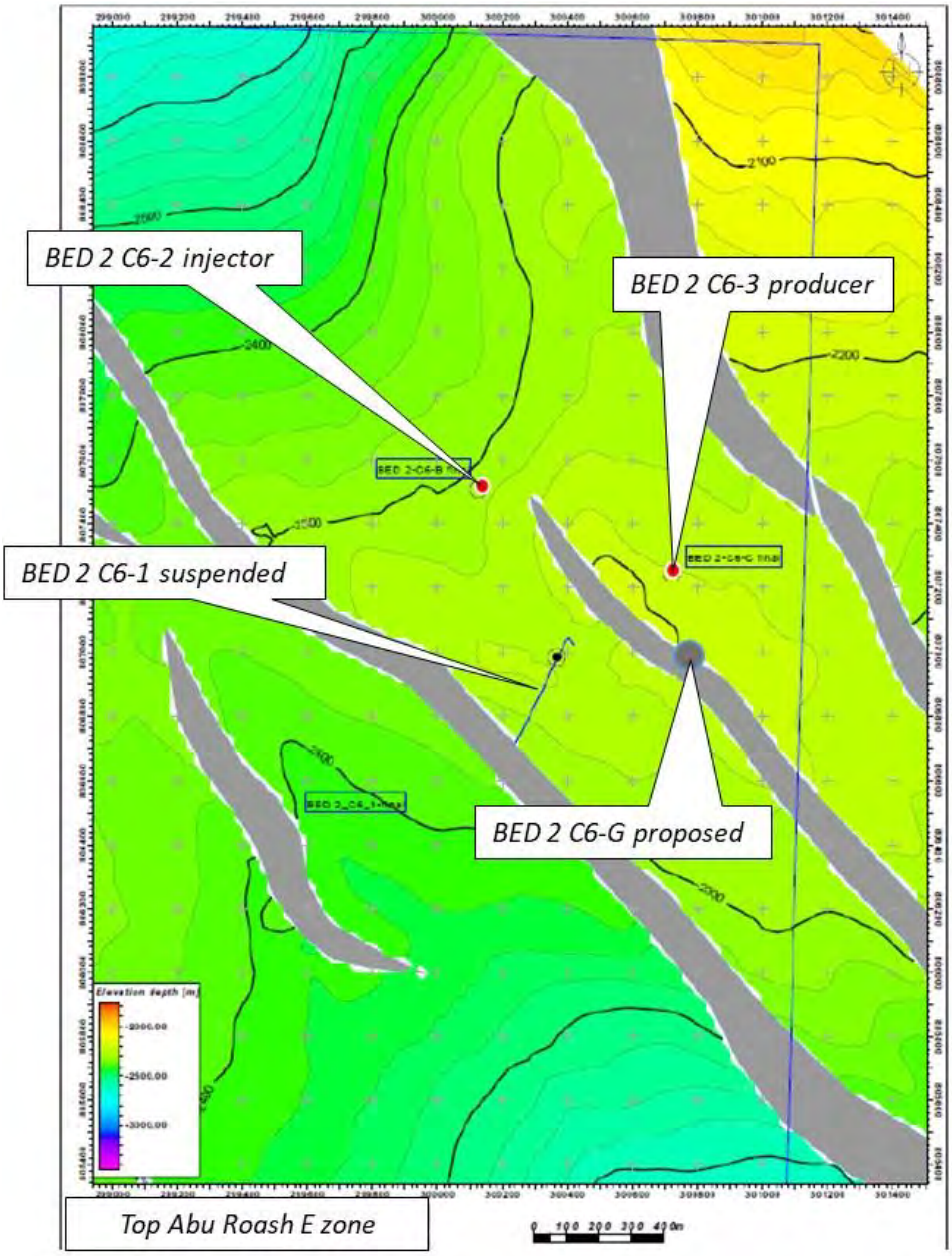
Source: Vendor vPDR

BED 2 C6 is a separate field, located approximately 6 km to the NE of the main BED 2 field. This is also controlled by normal faults to the NE and SW, and 2-way dip closure (Figure 26).

BED 16 is a structural trap, fault-closed by two normal faults to the south, but dip-closed to the north.

BED 17 is also a structural trap, controlled by a major normal fault on its northwestern boundary, but consisting of a complex of fault terraces bounded by an array of approximately NW-SE trending faults. Closures exist both in footwall and hangingwall traps.

Figure 26: BED 2 C6 Top Abu Roash E Depth Structure Map (m)



Source: Vendor vPDR

2.2.1.2 *Reservoir*

BED 2 is productive from sandstone reservoirs in the Abu Roash B, C, D, E and G zones, the Bahariya, and Kharita Formations.

BED 2 C6 produces primarily oil from Abu Roash E sandstones, with some additional potential in the carbonates of the Abu Roash D zone. Existing wells appear to define a NE-SW alignment of the Abu Roash E sandstones. There is thus question of continuity of reservoir onto the undrilled SE flank of the field.

BED 16 contains gas in the lower reservoirs of the field, the Bahariya and Kharita Formations, but oil in the Abu Roash C, E and G zones.

Oil reservoirs at BED 17 occur in the Abu Roash C and G zones, and in the Bahariya, but one zone in the Abu Roash E is gas-bearing.

2.2.1.3 Reservoir and Fluid Properties

PVT data are available from a small number of wells in the BED 2 cluster (Table 35). Gas compositions reported from separator gas are low in CO_2 (BED 2 ARG 0.52 mol%, BED 2-3 LBAH 1.33%), except at BED16, where 5.03 mol% CO_2 is reported. Overall pressure and temperature gradients are normal.

Table 35: BED 2 Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BED 2-2	ARG	No data	86.9	3,186	3,186	Not known	43	0.02	Not known
BED 2-3	LBAH	2,437	97.2	3,631	3,610	Not known	19	0.02	0.66
BED 16-3	KHAR	Not known	141.1	6,367	4,862	Not known	24	Not known	0.67

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
BED 2 C6-1	ARE	2,222	86.9	3,379	508	1.10	130	1.91	30
BED 16-4	ARC	Not known	120.6	5,186	1,305	1.28	381	0.55	39

2.2.1.4 Production Facilities

At Badr El-Din 2 (BED 2), the remote gathering station separates production fluids from the BED 2 area before export via pipeline to the BED 3 processing plant for further treatment (see section 2.3).

2.2.2 HIIP

GaffneyCline checked the petrophysical interpretations made by the Vendor by making an independent analysis of data available for three wells BED 2-2, Sitra 8-18 and Sitra 8-33. This generally validated the Vendor analyses for the BED/Sitra area and gave confidence in the petrophysical inputs to the static models and the targets identified for recompletions. It should be noted however, that data quality and coverage is only moderate, with limited log and core data available and poor borehole quality in some wells.

Particular attention was paid to assessment of the Marginal and Low Resistivity Pay (LRP) that it is used by the Vendor to ascribe upside potential to the Bahariya and Kharita Formations. The reports provided describing the Vendor's analysis and showing the presence of thin hydrocarbon-bearing reservoirs were reviewed by GaffneyCline. Thin-bedded reservoirs do appear to be present, and hydrocarbon volume in these intervals would be under-estimated by conventional log analysis methods.

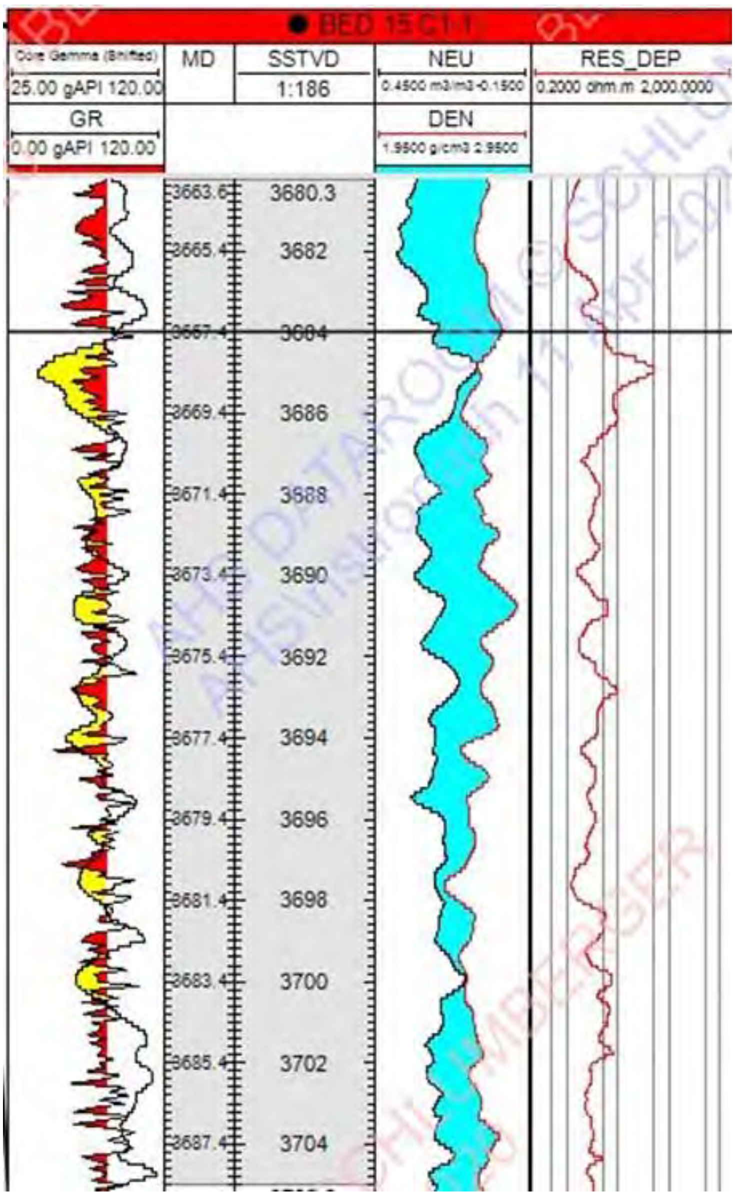
HIIP has not been closely re-evaluated by GaffneyCline for the established producing reservoirs, but it has been for the Bahariya Formation, where significant upside is described by the vendor. This relies on the recognition of poor quality and "low resistivity pay" (LRP) intervals that have not been currently exploited. As well as resulting from errors and uncertainties in previous petrophysical analysis, newly recognized LRP may result from:

- Thin beds not fully resolved by wireline log data;
- Clay (illite) bound water;
- Structural water in mixed-layer clays – basement for this reportedly at 3,500 m.

Comparison of core and wireline log data from the BED 15 area (Figure 27) show that indeed thin sandstone beds may not be fully recognised in the latter dataset, but also that overall bed thickness may be exaggerated. Certain zones (e.g. the Uppermost Bahariya 0 unit, Figure 28) may have substantial gas unrecognised because of high clay content. The Vendor claim uplifts of GIIP by including LRP ranges from 16 to 34%. The main Upper Bahariya 3 unit seems to be associated with 46% increase. A 2017 study by the Vendor records a general 40% increase. GaffneyCline's review suggests that this resource may be present and indicative volume uplift may be correct, but poor reservoir connectivity and predictability suggests that its effect on recoverable gas volumes may be relatively small.

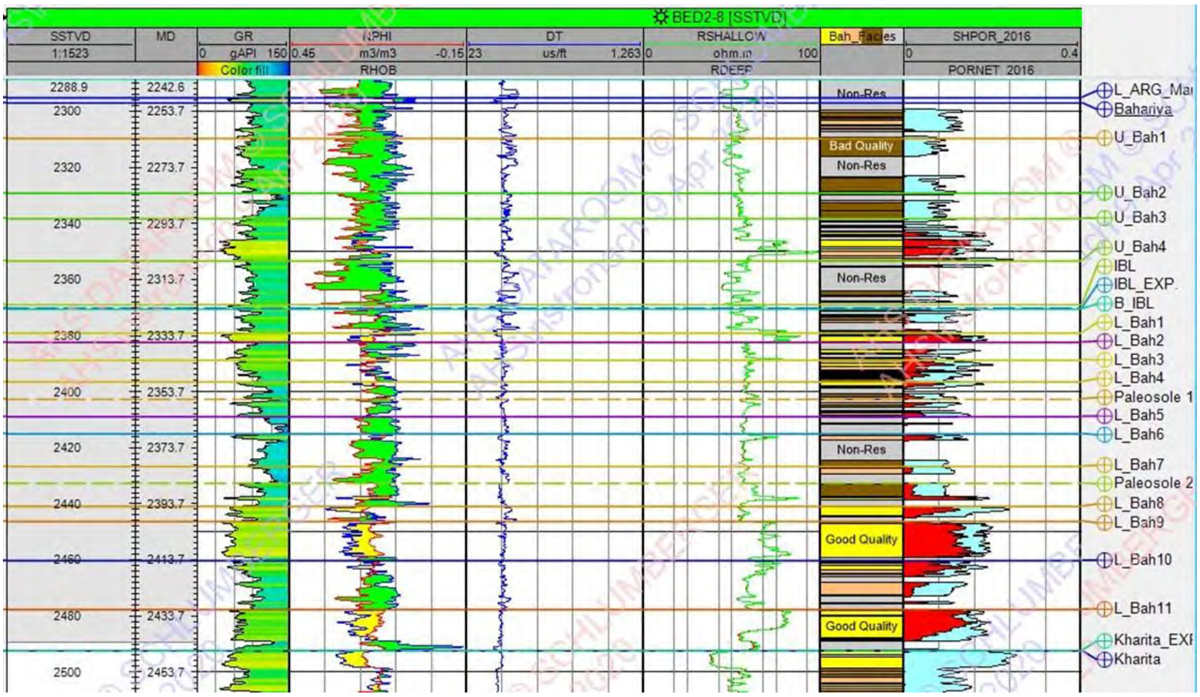
A summary of GIIP estimates for BED-2 is shown in Table 36 and STOIIP in Table 37.

Figure 27: BED 15 C1-1. Comparison of Core and Wireline Gamma Log, Upper Bahariya Formation



Source: Vendor vPDR

Figure 28: BED 2-8: Bahariya Formation Reservoir Section



Source: Vendor vPDR

Table 36: BED 2 Cluster GIIP

<table>
<tr><th rowspan="2">Location</th><th rowspan="2">Source</th><th rowspan="2" colspan="2">Reservoir</th><th colspan="3">GIIP (Bscf)</th><th rowspan="2">Notes</th></tr>
<tr><th>Low</th><th>Best</th><th>High</th></tr>
<tr><td>BED 2 T</td><td>Vendor VDR</td><td colspan="2">Apollonia</td><td>43.8</td><td>76.1</td><td>139</td><td>Total volume of seismic anomaly, covering three fault blocks</td></tr>
<tr><td rowspan="9">BED 2</td><td rowspan="3">Vendor VDR</td><td colspan="2">Abu Roash BCD</td><td>85.7</td><td>101</td><td>116</td><td></td></tr>
<tr><td colspan="2">Abu Roash E</td><td>88</td><td>97</td><td>108</td><td></td></tr>
<tr><td colspan="2">Abu Roash G</td><td>141</td><td>159</td><td>177</td><td></td></tr>
<tr><td rowspan="6">GaffneyCline Estimate in Best Case. Low and High from vendor VDR.</td><td rowspan="3">Upper Bahariya</td><td>Good sand facies</td><td rowspan="6">1,268</td><td>119</td><td rowspan="6">1,384</td><td rowspan="6">Based on 2017 modelling study and on calculations in vPDR database. Total GIIP to be targeted by new drilling is 707 Bscf in “poor” and “LRP” reservoir facies. Low and High case ranges not defined for each category. The range quoted by vendor does not fully express uncertainty in “poor” and “LRP” facies.</td></tr>
<tr><td>Poor sand facies</td><td>273</td></tr>
<tr><td>LRP</td><td>197</td></tr>
<tr><td rowspan="3">Lower Bahariya</td><td>Good sand facies</td><td>499</td></tr>
<tr><td>Poor sand facies</td><td>138</td></tr>
<tr><td>LRP</td><td>99</td></tr>
<tr><td>BED 2 C4</td><td>Vendor VDR</td><td colspan="2">Abu Roash D</td><td>14.3</td><td>46</td><td>92.3</td><td></td></tr>
<tr><td>BED 2 J11</td><td>Vendor VDR</td><td colspan="2">Upper Safa</td><td>4.4</td><td>18.5</td><td>35.3</td><td></td></tr>
<tr><td>BED 16</td><td>Vendor VDR</td><td colspan="2">Bahariya and Kharita</td><td>-</td><td>106</td><td>-</td><td></td></tr>
<tr><td>BED 17</td><td>Vendor VDR</td><td colspan="2">Abu Roash E</td><td>-</td><td>21</td><td>-</td><td></td></tr>
</table>

Table 37: BED 2 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
BED 2C6	Vendor volume calculation and Vendor FDP	Abu Roash B	4.4	7.1	11.3	From mix of material balance and static calculations, generally validated by GaffneyCline.
		Abu Roash C	-	4.9	9.5	
		Abu Roash D	3.6	5.5	8.1	
		Abu Roash E	1.7	3.1	3.7	
BED 2 C4	Vendor VDR	Abu Roash E	3.1	9.5	20.8	
BED 2 C3-1	Vendor VDR	Lower Bahariya	7.9	10.6	13.9	
BED 16	Vendor VDR	Abu Roash C	-	4	-	
		Abu Roash E	-	6	-	
		Abu Roash G	-	9	-	
BED 17	Vendor VDR	Abu Roash C	-	3	-	
		Abu Roash G	-	4	-	
		Bahariya	-	2	-	

2.2.1 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 38.

Table 38: BED 2 Cluster: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
BED 2 NFA	BED 2 NFA		**Reserves**
BED 16 NFA	BED 16 NFA		**Reserves**
BED 17 NFA	BED 17 NFA		**Reserves**
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
BED 16 infill	BED 16 infill		**Reserves**
BED 2 infill	BED 2 infill (BED 2C6 and BED 2-C3)	Additional drilling in Abu Roash E reservoir	**Reserves**
General infill	Not included	All development activity viewed as covered by other categories.	N/A
BED 2 C2E	BED 2 NFE	Suite of discoveries requiring further appraisal and prospects.	Both **Contingent and Prospective Resources**
BED 17 C2E	BED 17 NFE	Satellite structures to	**Prospective Resources**
Upside	BED 2 upside	Bahariya Formation	**Contingent Resources**. Development plans require further detail in view of reservoir uncertainty.

2.2.2 Historical Field Performance

2.2.2.1 BED 2

Gas production from the Bahariya reservoir started in 1992 with well BED 2-1 and 10 further development wells were drilled by 2006. The BED 2 gas production history is shown in Figure 29.

Figure 29: Historical Gas and CGR Production Rates, BED 2 (Bahariya)

Oil production from the C6 reservoir commenced in 2014 and peak production of 1,400 bopd from four wells was reached in 2018. At end 2019, it was producing from one well BED 02 C6-3 with an average rate of 400 bpd and a watercut of 9.5%. The BED 2 oil production history is shown in Figure 30.

Figure 30: Historical Oil Production Rate, BED 2 (C6)

2.2.2.2 BED 16

Oil production commenced in 1990 and gas production in 2005. Oil production increased in 2006 to 750 bpd with the drilling of BED 16-4 and 16-8. Current production is from well BED 16-8 with rate of 400 bopd.

Figure 31 and Figure 32 show the gas and oil production history for the BED 16 field respectively.

Figure 31: Historical Gas and Water Production Rates, BED 16 Kharita and Bahariya Reservoirs

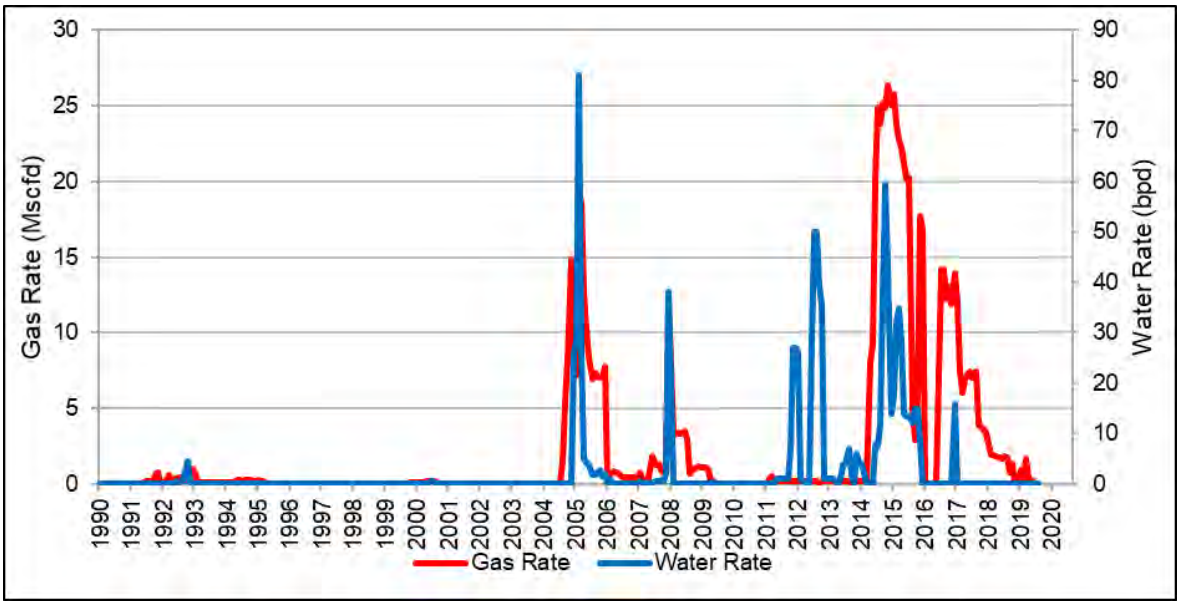
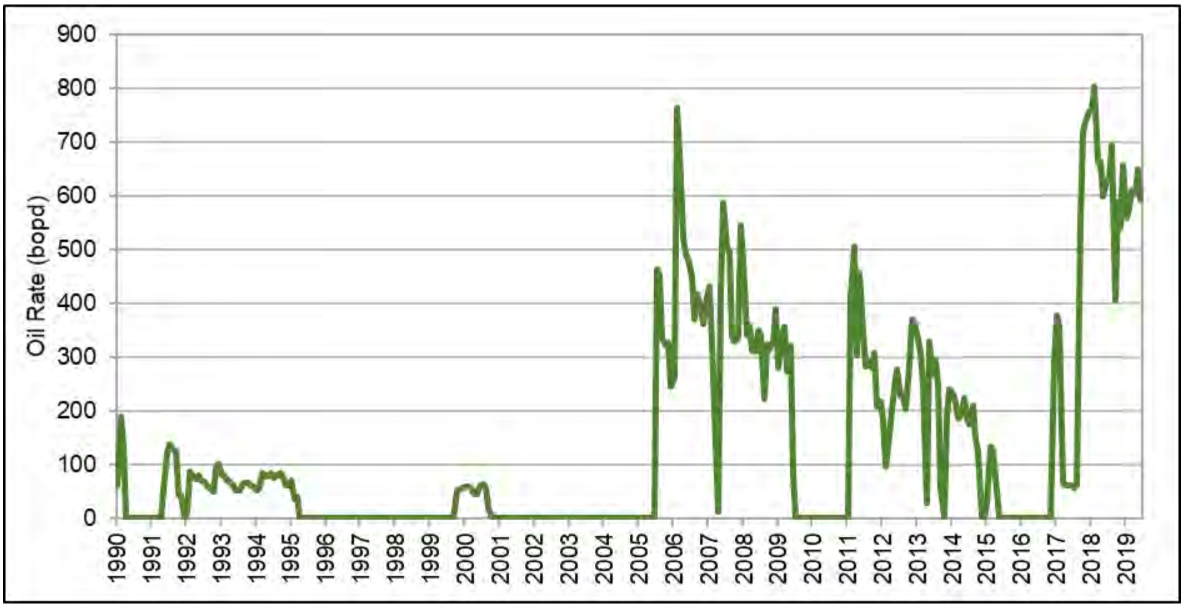


Figure 32: Historical Oil Production Rate, BED 16



2.2.2.3 Summary

The BED 2, 16 and 17 historical production performance is summarized in Table 39.

Table 39: BED 2, 16 and 17 Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
BED 2	12	1.5	830.5	530.4	13.8	951.8
BED 16	2	1.5	24.9	615.0	0.6	0.0
BED 17	1	0.2	5.8	147.7	0.0	2.0
Total	**15**	**3.2**	**861.2**	**1,293.1**	**14.5**	**953.8**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.2.3 Field Development Plan

2.2.3.1 BED 2

The consortium's future development plans for the fields include the following activities:

- One new horizontal infill oil producer planned in the BED 2 C6 (ARE and ARD) area in 2020.

  At the Effective Date, BED 2 C6 was producing from a single producer-injector pair. A further production well was planned to target the crestal area of the main fault block and to improve drainage of the southeastern flank of the field, although there is some uncertainty over sand continuity into this area. This well has been drilled as BED 2 C6-5 in 1Q 2020, post the Effective Date of this report, and is successfully on stream as an oil producer.

- No new firm wells are planned in the Bahariya gas reservoirs. Eleven new wells and four workovers assumed in the Bahariya gas reservoir are considered as Contingent Resources.

  Modelled sandstone reservoir development is concentrated in the crestal parts of the field, with more limited and discontinuous sandstones on the flanks. The Consortium proposes the 11 well campaign to specifically target the untapped more marginal reservoirs and LRP (see above). No specific locations are defined but in general terms a small number of axial targets may be able to be defined using the existing dataset, but those on flank of field are high risk due to (i) poor reservoir presence, (ii) uncertain distribution of marginal facies and (iii) proximity to water. These resources have been estimated using the static model for the reservoir, but are here considered Contingent on demonstration of satisfactory targeting of undrained low quality reservoirs and demonstration of successful production performance.

- Appraisal and development of discoveries made in the Lower Bahariya.

  An oil discovery has been made at BED 2 C3-1 in the Lower Bahariya and Kharita Formations in the extreme south of the BED 2 block. A small 3-way dip closure is controlled by a normal fault on its NE margin. Two main sandstones are present with approximately 15 m of net pay, but with several subordinate units, and porosity is approximately 18%. Two further firm wells were planned to further appraise and develop this. Subsequent to the Effective Date of this Report, in 1Q 2020, wells BED 2 C3-2 and BED 2 C3-3 have been drilled, although the latter required sidetracking as BED 2 C3-3ST to find optimum reservoir. Both are successfully on stream as oil producers from the Lower Bahariya Formation. Thus two new wells as well as well BED 2 C3-1 have been included in the Reserves estimates. BED 2 C3 wells are verticals.

- Appraisal and development of discoveries made in the Apollonia Formation.

  The Consortium has provided a detailed model of reservoir development in the Apollonia Formation at BED 19. On this basis further potential is ascribed to similar structures at BED 2. Gas is discovered at BED 2-7 and mapping of seismic amplitude attributes suggests that the pool straddles three normal fault blocks extending northeastwards to BED 2 C6, where there are more tentative gas indications at BED 2 C6-2. The target is extremely shallow at around 800 m, so porosities may exceed 0.4, and the gas is dry. Only one well is currently scheduled, so the resources remain Contingent on firming a more complete development plan.

The schedule for the firm activities above has been defined in the consortium's Business Plan and is summarized in Table 40.

Table 40: BED 2 C6 and C3 Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	4	0	0	0	0	**4**
Injection Wells	0	0	0	0	0	**0**
Total	**4**	**0**	**0**	**0**	**0**	**4**

2.2.3.2 BED 16

The Consortium's future development plans for BED 16 includes four new infill wells in the Kharita and Bahariya gas reservoirs (Table 41) and three new infill wells in the ARG oil reservoir (Table 42). These are understood to be targeting western, crestal areas of the field.

Table 41: BED 16 Kharita and Bahariya Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	1	3	0	**4**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**1**	**3**	**0**	**4**

Table 42: BED 16 ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	3	0	0	**3**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**3**	**0**	**0**	**3**

2.2.3.3 BED 17

No new infill wells are planned in the near future. No Contingent Resources are included in the "near field exploration" programme.

2.2.4 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (10th April 2034).

Table 43 and Table 44 show the remaining technically recoverable gas and oil volumes for the BED 2 cluster.

Table 43: Remaining Technically Recoverable Gas Volumes, BED 2 Cluster, as at 31st December 2019

Area	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
BED 2	24.3	**31.0**	36.9
BED 16	4.4	**27.0**	51.1
BED 17	0.0	**0.0**	0.0
SI Re-activation	0.3	**0.3**	0.4
Total	**29.0**	**58.3**	**88.4**

Notes:

1. The volumes in this table are to April 2034; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 44: Remaining Technically Recoverable Oil and Condensate Volumes, BED 2 Cluster, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
BED 2	3.3	3.9	4.7
BED 16	0.8	2.1	3.3
BED 17	0.0	0.0	0.1
SI Re-activation	0.5	0.5	0.5
Total	**4.6**	**6.5**	**8.6**

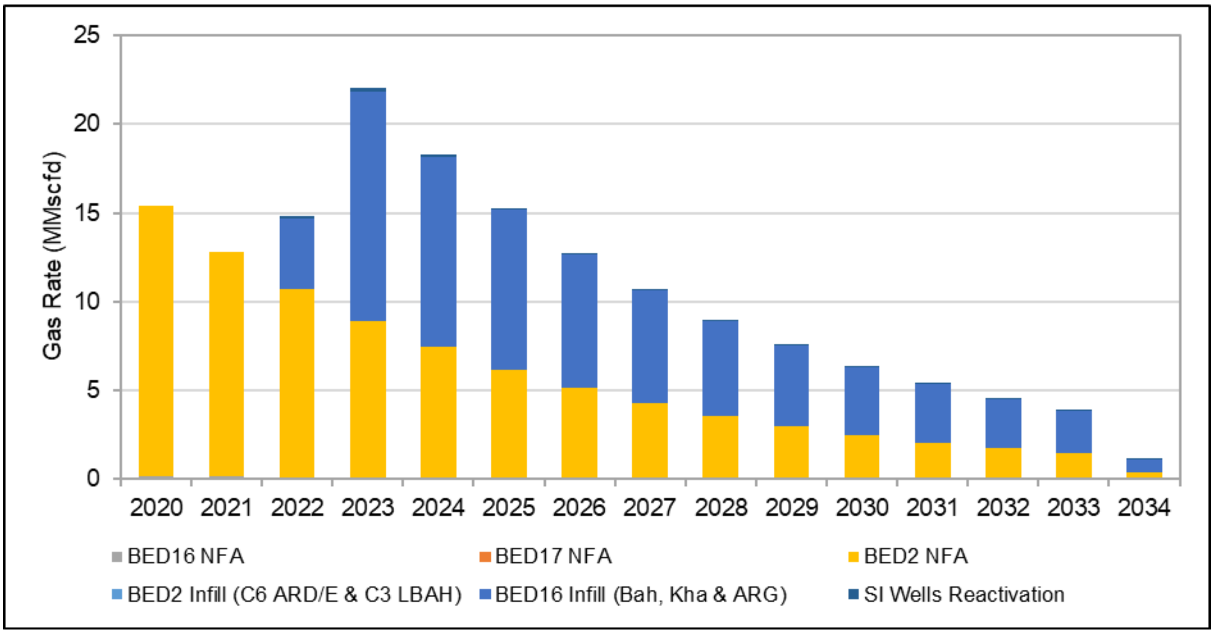
Notes:

1. The volumes in this table are to April 2034; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 33 and Figure 34 show the gas and oil production forecasts for the BED 2 cluster by activity.

Figure 35 and Figure 36 show the Low, Best and High production forecasts for the BED 2 cluster.

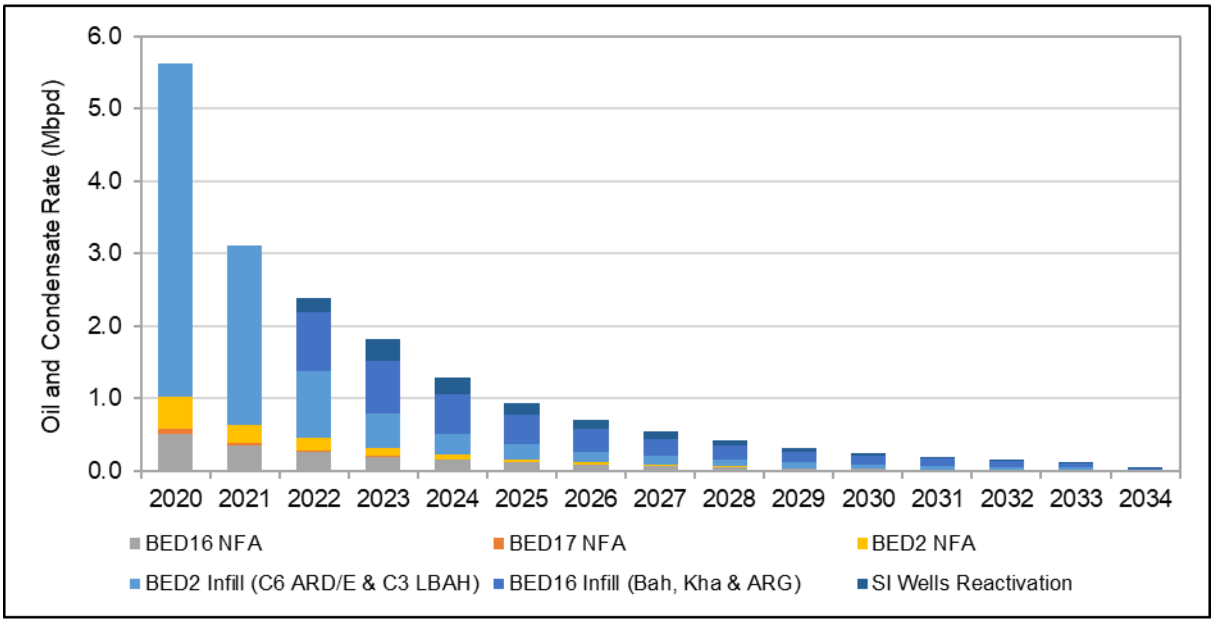
Figure 33: Best Case Gas Production Forecasts, BED 2 Cluster



Notes:

1. The values in this figure are annual average rates and in 2034 include production only until April; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

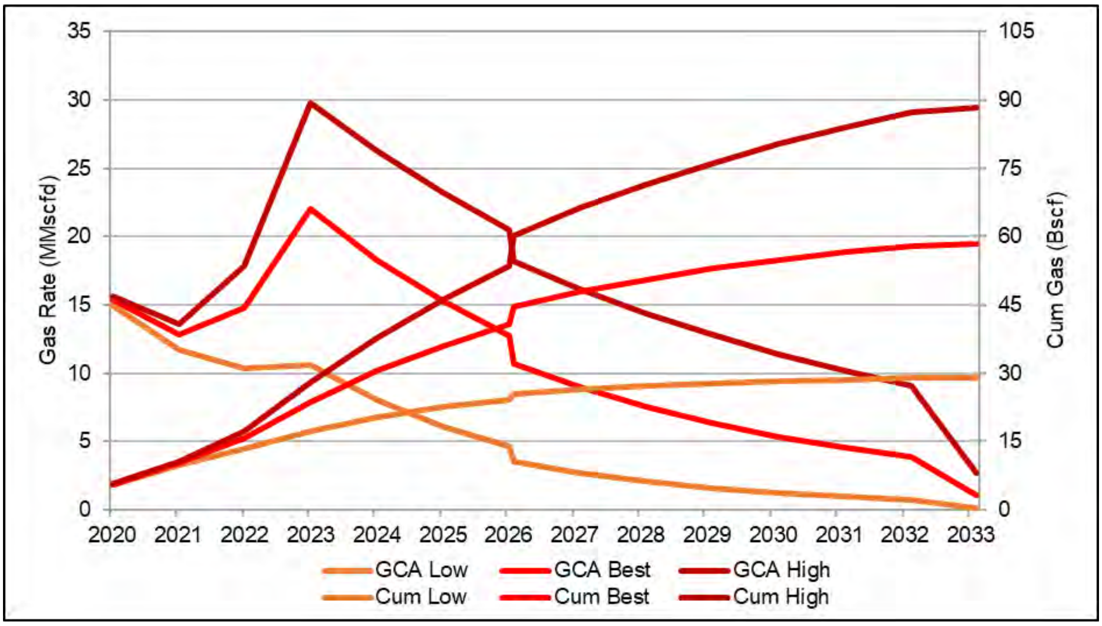
Figure 34: Best Case Oil and Condensate Production Forecasts, BED 2 Cluster



Note:

1. The values in this figure are annual average rates and in 2034 include production only until April; no economic cut off has been applied.

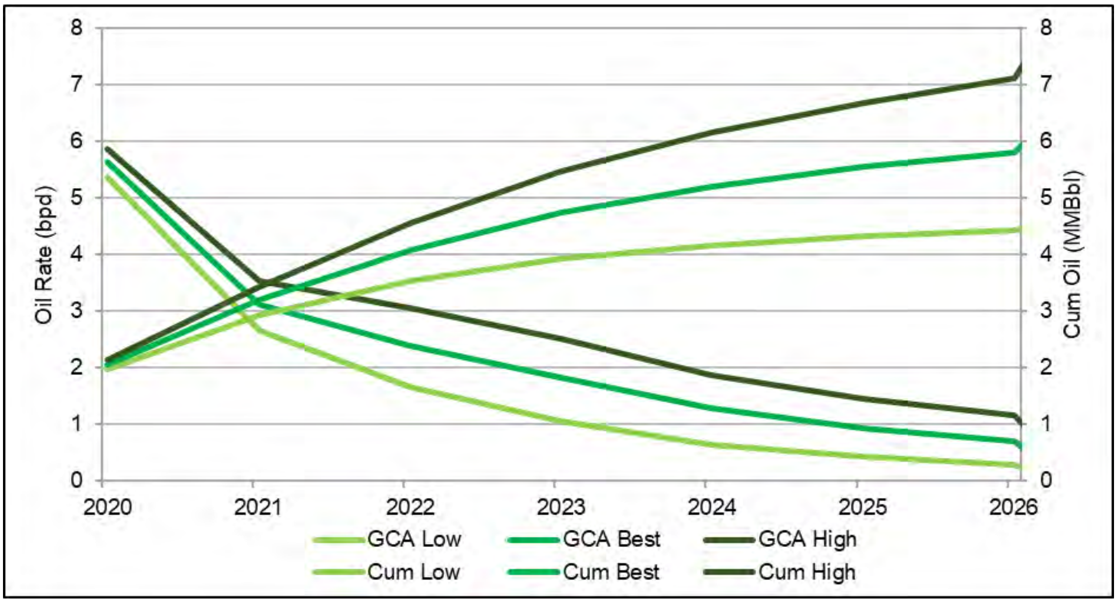
Figure 35: Gas Production Forecasts, BED 2 Cluster



Notes:

1. The values in this figure are annual average rates and in 2034 include production only to April; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 36: Oil and Condensate Production Forecasts, BED 2 Cluster



Note:

1. The values in this figure are annual average rates and in 2034 include production only to April; no economic cut off has been applied.

2.2.5 Contingent Resources

Contingent Resources were assigned to wells where further clarification of the development is required to address technical uncertainty. Further modelling work is required to bring to these opportunities to a higher level of confidence.

The incremental production from 11 infill gas wells in the BED 2 Bahariya reservoir are considered as Contingent Resources. In addition, the incremental production from four workovers is also considered as Contingent Resources.

There are Contingent Resources assigned to BED 2 in the Apollonia, ARB and ARD reservoirs.

The BED 2 Contingent Resources are summarized in Table 45.

Table 45: Gross Contingent Resources, BED 2 Cluster, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
BED 2 (Bahariya)	18.0	35.3	55.5
BED 2 (Apollonia)	8.3	23.3	52.3
BED 2 C6 (ARB)	0.0	0.0	0.0
BED 2 C6-HA (ARD)	0.0	0.0	0.0
Total	**26.3**	**58.6**	**107.8**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
BED 2 (Bahariya)	0.2	0.7	1.1
BED 2 (Apollonia)	0.0	0.0	0.0
BED 2 C6 (ARB)	0.5	0.7	1.1
BED 2 C6-HA (ARD)	0.6	0.9	1.5
Total	**1.3**	**2.3**	**3.7**

Notes:

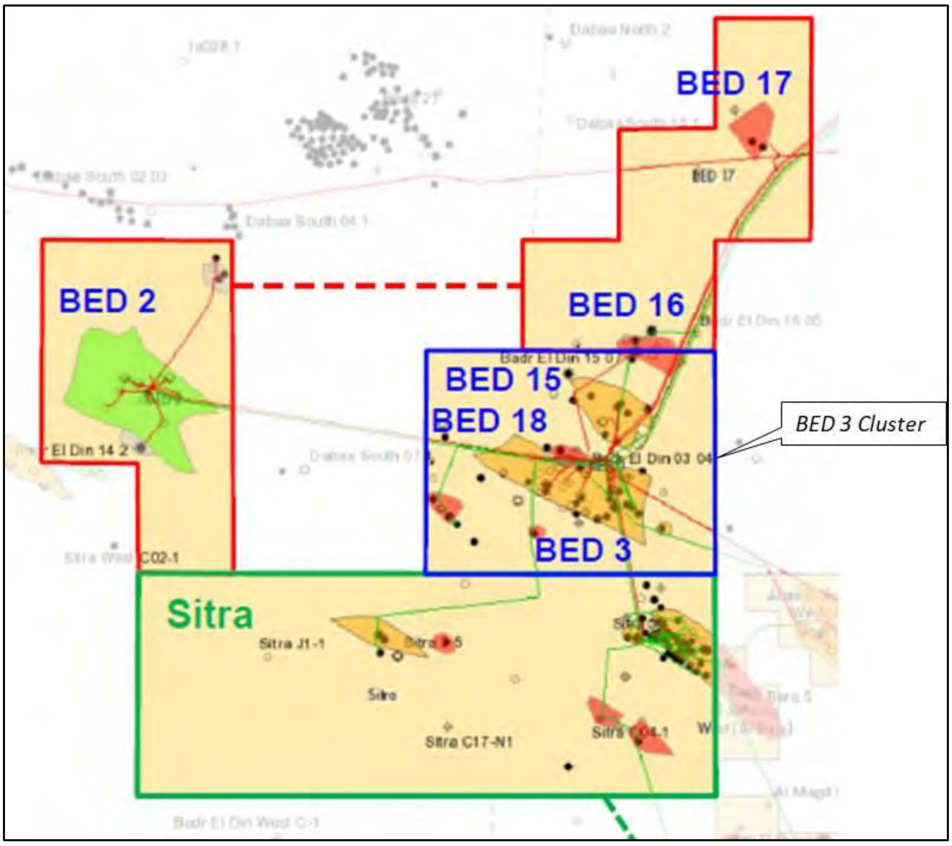
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.3 BED 3 Cluster

2.3.1 Asset Description

The BED 3 cluster, as described by the Consortium, consists of the BED 3, BED 15 and BED 18 development leases (Figure 37).

Figure 37: BED 3 Cluster Location Map



Source: Vendor VDR

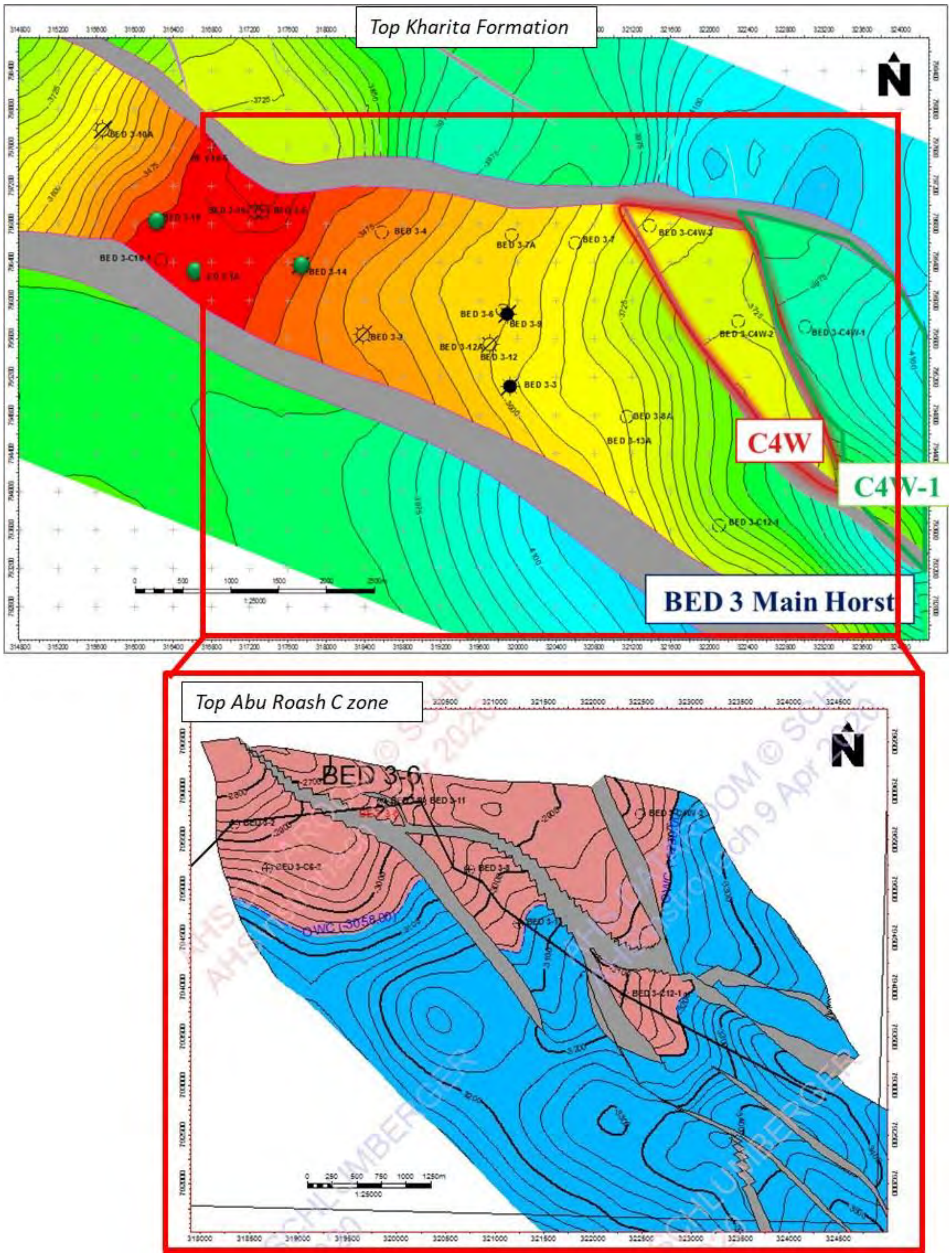
2.3.1.1 *Structure and Trap*

BED 3 is the principal field and comprises a complex of individual fault blocks, associated with a major NW-SE trending horst at depth whose bounding faults splay upwards and southwards. There is thus a relatively simple structure at Bahariya Formation level, but more complex fragmentation of the structure within the Abu Roash Formation. Individual fault blocks may thus have a component of NW or SE dip closure. The fault block and well nomenclature is complex, with individual component and satellite fault blocks carrying distinct names. Representative depth structure maps are shown in Figure 38.

BED 15 is controlled by a major NW-SE trending normal fault system. Closures in the deep section, at Kharita level are in the footwall of this fault, with dip closure to the NE. In the shallower, Abu Roash section, hydrocarbons also occur in the hangingwall section and appear to be partly stratigraphically controlled along N-S trending sandstone fairways.

BED 18 occupies the footwall of a major E-W trending fault. A N-S fault trend separates the field into west and east compartments. It appears that the orientation of the sandstone trend in the main Abu Roash G reservoir approximately aligns with the structural trend.

Figure 38: BED 3 Kharita Formation and Abu Roash C Reservoir, Depth Structure Maps (m)



Source: Vendor VDR and vPDR

2.3.1.2 Reservoir

BED 3 reservoirs are oil bearing in the Abu Roash C, E and G zones, and in the Upper Bahariya Formation, and gas-bearing in the Lower Bahariya and Kharita Formations. Most recent drilling success has been in the Abu Roash G. This unit consists of approximately NW-SE aligned shoreline trends, cut by orthogonal tidal channel and delta deposits. This creates a complex sand architecture which leads to uncertainty in volumetric estimates, but also further drilling opportunities.

Reservoirs at BED 15 are oil-bearing in the Abu Roash C and E zones and in the Upper Bahariya Formation, and gas-bearing in the Lower Bahariya and Kharita Formations. The principal oil bearing sandstone is oriented axially along the crest of the field.

BED 18 is an oil field in the Abu Roash E and G zones.

2.3.1.3 Reservoir and Fluid Properties

PVT data are available for representative medium and light oil samples in the Abu Roash Formation, and from gas in the deeper Bahariya and Kharita Formations (Table 46). In the gas reservoirs, CO_2 content in the samples ranges up to 4.87 mol% at BED 3-10 in the Kharita Formation. Pressure and temperature gradients are indicated to be normal.

Table 46: BED 3 Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BED 15-5	KHA	Not known	126.7	Not known	5,625	Not known	20	0.01	0.68
BED 3-10	KHA	Not known	Not known	Not known	Not known	Not known	80	Not known	0.69
BED 3-4	BAH	Not known	126.1	5,445	5,390	Not known	Not known	Not known	
BED 3-2	KHA	3,516	122.2	5,523	5,440	0.0040	44	Not known	0.66

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
BED 3 C6-1	ARG	3,345	121.7	5,250	1,668	1.22	303	1.98	33
BED 3 C9-1	ARG	Not known	115.6	4,980	4,100	1.75	1336	0.25	44
BED 18-2	ARG	3,275	119.7	5,347	1,675	1.32	433	0.69	32
BED 3-8	ARC	3,037	112	4,363	2,450	1.75	990	0.25	42
BED 3-6	ARC	2,808	106.7	Not known	2,243	1.75	1036	0.23	38

2.3.1.4 Production Facilities

The facilities at the BED3 main processing plant serve as the processing point for the BED3 area. The development of BED3 has grown organically and the main processing plant is supplied with production fluids from a number of remote gathering stations/facilities, namely:

- o Badr El-Din 2 (BED2) facility;
- o Sitra Early Production Facility (EPF);
- o Al Barq facility (AESW);
- o Bagha facility (AESW); and
- o North East Abu Gharadig JD facility.

The BED 3 processing plant has three main gas processing trains operating at high pressure, medium pressure and low pressure. Each gas train separates, compresses (MP and LP trains only), dehydrates, and recovers NGLs to ensure the export gas is of sales quality. The BED3 plant has the potential to process up to 340 MMscfd of gas, and 30 MBbl/day condensate.

The treated gas from BED3 is then exported to Amereya. Condensate is stabilised and dehydrated before being exported to Hamra Terminal for offtake by tanker. Condensate from Bagha and Al Barq facilities are sent directly to the storage tanks at BED3.

2.3.2 HIIP

GaffneyCline has evaluated the HIIP provided by the Vendor, with particular emphasis on confirming the Best Case for the established oil reservoirs and the upside potential in the deep gas-bearing reservoirs. The lack of detailed reservoir maps and static models means that there is uncertainty around the precise HIIP in the more sedimentologically complex Abu Roash reservoirs, and this has not been fully evaluated in the Vendor dataset.

The gas and oil in place estimates are shown in Table 47 and Table 48.

Table 47: BED 3 Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			Notes
			Low	Best	High	
BED 3	Vendor VDR	Lower Bahariya	-	102	-	
		Kharita	-	1,200	-	
BED 15	Vendor VDR	Lower Bahariya	-	309	-	
		Kharita	-	263	-	Corroborated by GaffneyCline estimate

Table 48: BED 3 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
BED 3	Vendor VDR and FDP	Abu Roash C	4.8	12.8	17.3	Principally in BED 3-6 block (7 MMBbl) and in BED C6 block (6 MMBbl), where development activity anticipated
			-	5	-	Estimated additional volume in other fault blocks
		Abu Roash E	-	4	-	No range estimated.
		Lower Abu Roash G	5.5	8.7	27	BED C6 block only.
			-	4	-	Estimated additional volume in C18 block. No range estimated.
			-	24	-	Estimated additional volume including other BED 3 and satellite blocks. No range estimated.
		Upper Bahariya	-	20	-	No range estimated.
BED 15	Vendor VDR	Abu Roash C	-	45	-	No range estimated
		Abu Roash E/Upper Bahariya	-	21	-	No range estimated
BED 18	Vendor VDR	Abu Roash E	-	4	-	No range estimated
		Abu Roash G (West)	-	12	-	No range estimated
	GaffneyCline estimate	Abu Roash G (East)	-	4.3	-	No estimate provided by vendor. Approximate GaffneyCline estimate only.

2.3.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 49.

Table 49: BED 3 Cluster: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
BED 3 NFA	BED 3 NFA		**Reserves**
BED 15 NFA	BED 15 NFA		**Reserves**
BED 18 NFA	BED 18 NFA		**Reserves**
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
BED 3 infill	BED 3 infill		**Reserves**
BED 15 infill	BED 15 infill		**Reserves**
BED 18 infill	BED 18 infill	Mainly ARG wells to develop east of field.	**Reserves**
General infill	Not included	All development activity viewed as covered by other categories.	N/A
BED 3 C2E	BED NFE Included only in upside case	Mainly additional prospects in satellite structures (e.g. C9, C19)	**Prospective Resources**
Upside	BED 3 upside	Bahariya Gas	**Contingent Resources**. Development plans require further detail in view of reservoir uncertainty.
	BED 15 Upsides	Kharita Gas	

2.3.4 Historical Field Performance

2.3.4.1 BED 3

BED 3 production commenced in 1990 with BED 3-1 producing gas from the Kharita gas reservoir. Peak production of 200 MMscfd occurred during 1998 to 2001. The last well was drilled in 2011, adding 20 MMscfd.

BED 3 oil production started in 1991 with oil production in ARC, ARE and ARG reservoirs. Water injection in ARG began in 2012.

Historical field gas and oil production are shown Figure 39 and Figure 40 for the BED 3 field.

Figure 39: Historical Gas Production Rate and CGR, BED 3 (Kharita and Bahariya)

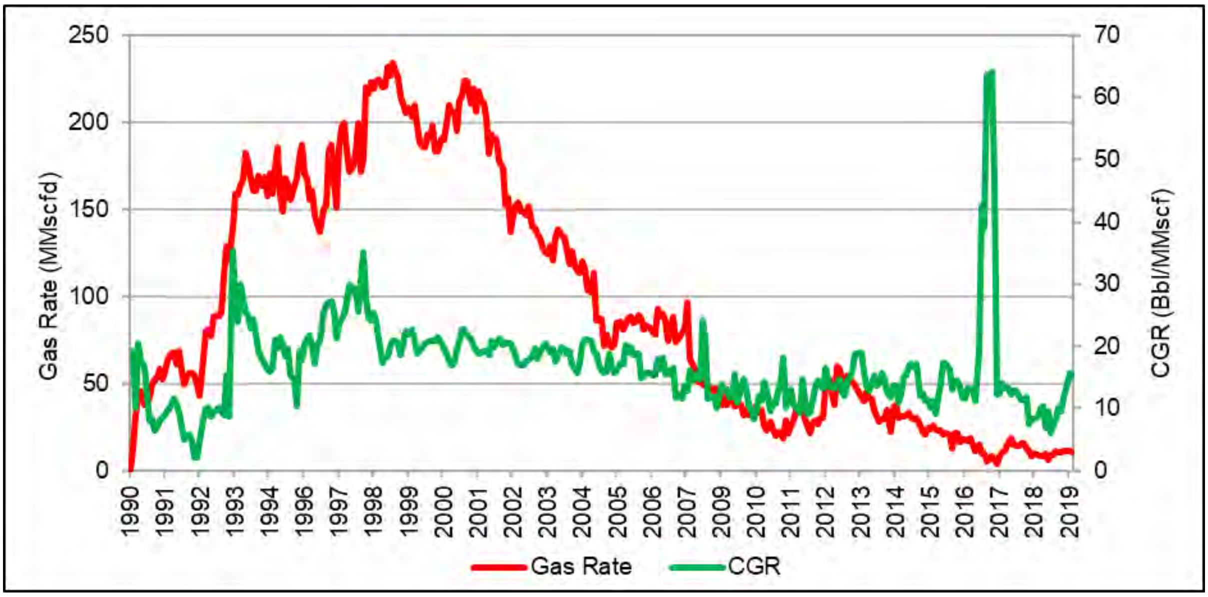
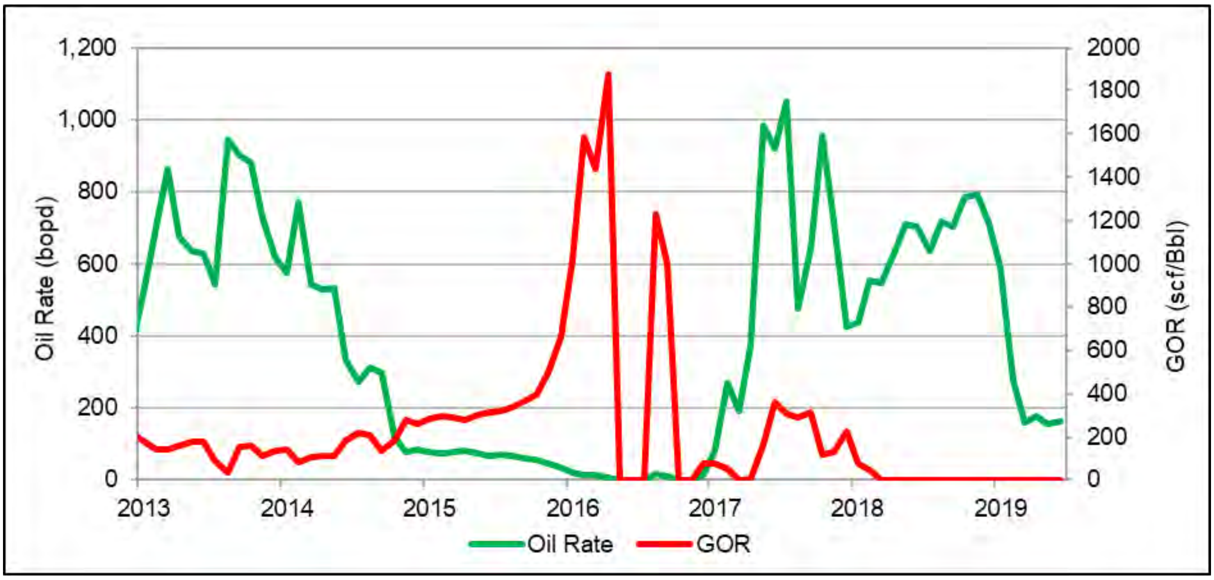


Figure 40: Historical Oil Production Rate and GOR, BED 3 (ARC and ARG)



2.3.4.2 BED 15

Oil production first started in 1989 with BED 15-1 well. Peak production of 5,000 bopd occurred in 1991 when BED 15-3 came on stream. Water injection started in 2003 with well BED 15-7, followed by well BED 15-8 in 2004 and well BED 15-9 in 2005. The last well was drilled in 2018 in a separate fault block.

First gas production came from the Kharita reservoir through well BED 15-5 in 1998 reaching a peak production of 45 MMscfd more than a year later. A second peak of production occurred in 2002 with the drilling of well BED 15-6. BED-11 and BED 15-12 followed in 2013 and 2018 respectively.

Historical field gas and CGR production profiles for the BED 15 Kharita gas are shown in Figure 41. Historical field oil and watercut production form the ARC formation are shown in Figure 42.

Figure 41: Historical Gas Production Rate and CGR, BED 15 (Kharita)

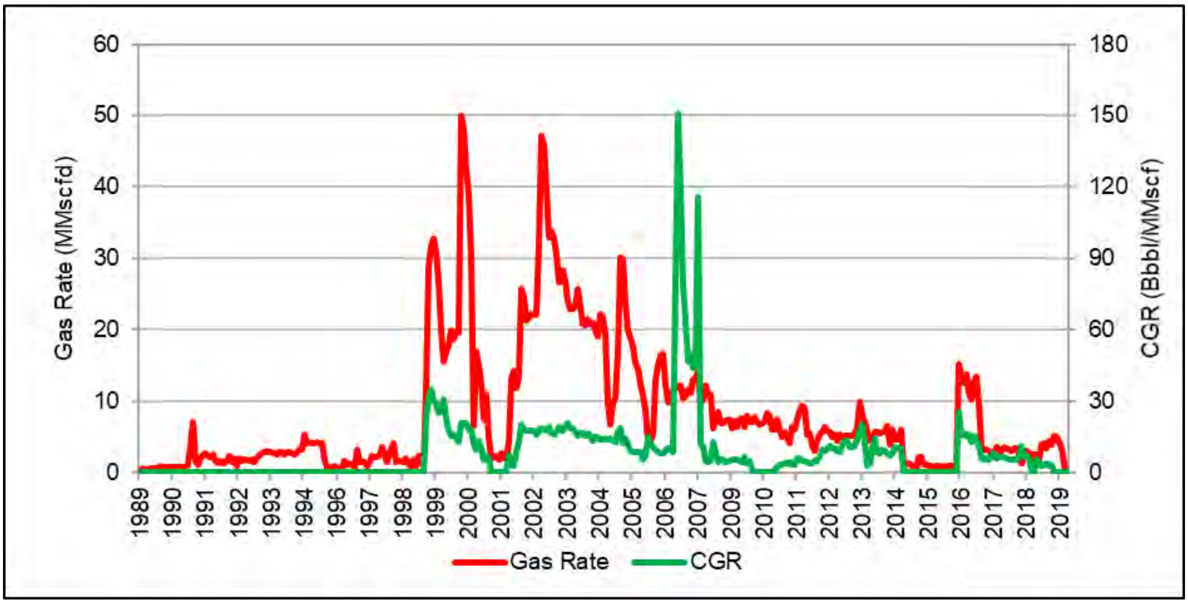
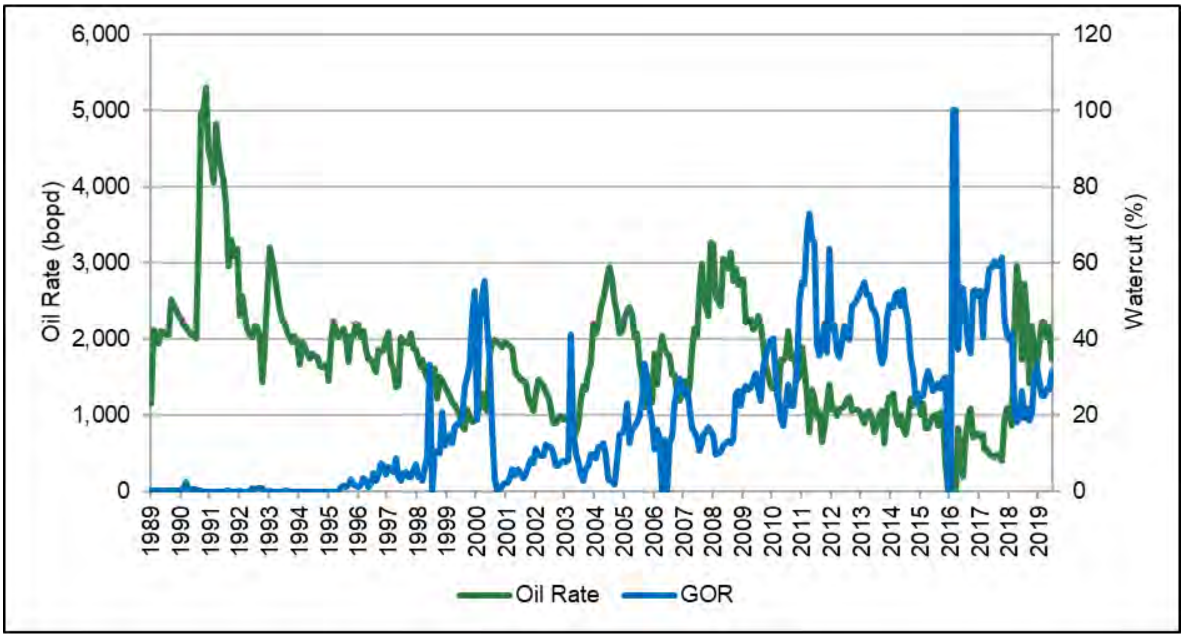


Figure 42: Historical Oil Production Rates and Water Cut, BED 15 (ARC)



2.3.4.3 BED 18

Oil production started in 2003 and peaked at approximately 1,300 bopd but had ceased by 2011. It restarted in 2013 and water injection commenced in 2016. Gas production commenced in 2004 but has been intermittent.

Historical Oil and water cut production profiles for BED 18 ARC are shown in Figure 43. Historical field gas production for BED 18 are shown in Figure 44.

Figure 43: Historical Oil Production Rates and Water Cut, BED 18 (ARG)

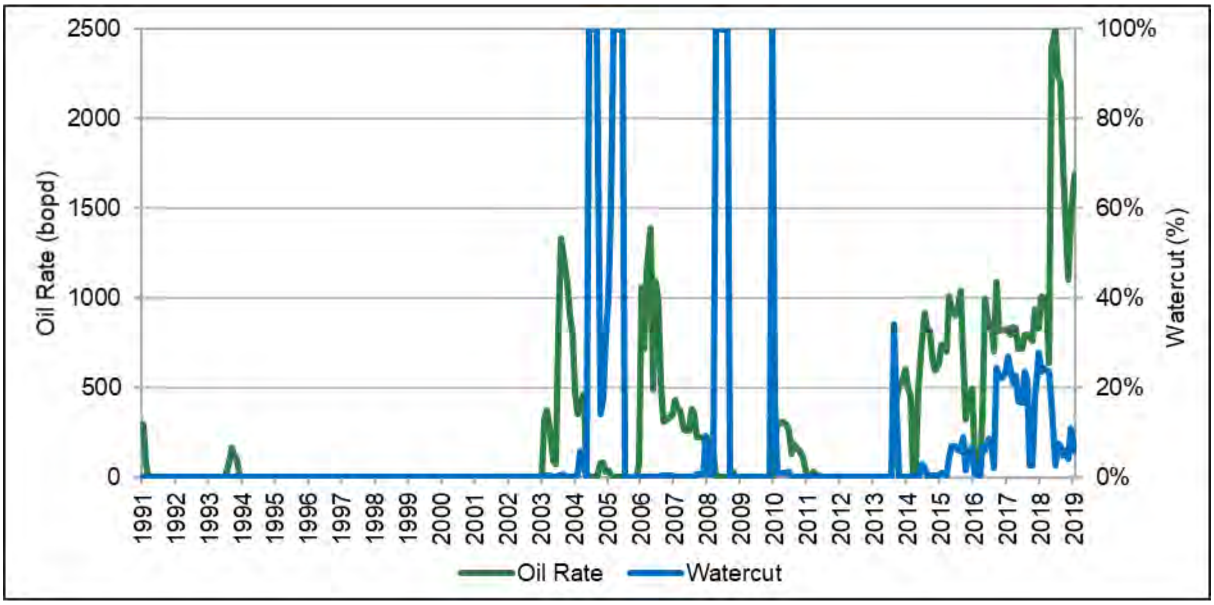
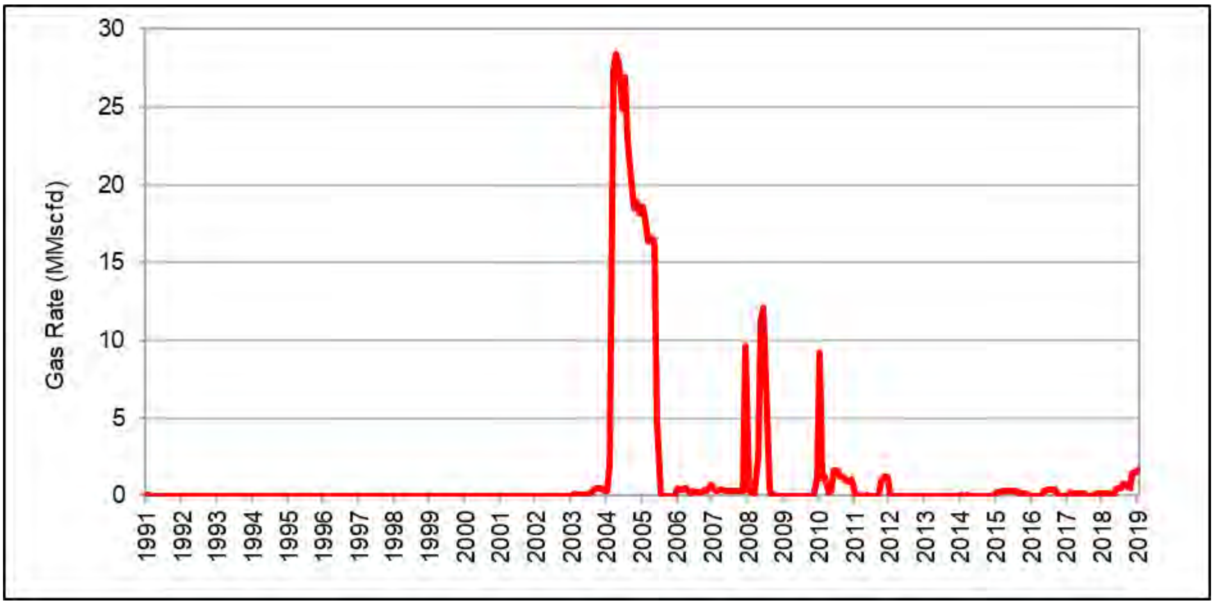


Figure 44: Historical Gas Production Rates BED 18 (ARG)



2.3.4.4 Summary

The cumulative produced gas and oil volumes as well as injected volumes for BED 3, BED 15 and BED 18 are summarized in Table 50.

Table 50: BED 3, 15 and 18 Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
		MMBbl	Bscf	bopd	MMscfd	bwpd
BED 3	20	34.4	1,032.0	5,087.3	33.5	2,096.5
BED 15	3	19.4	92.4	2,035.8	4.5	772.5
BED 18	5	21.8	105.1	3,447.6	5.8	876.5
Total	**28**	**75.6**	**1,229.5**	**10,570.8**	**43.8**	**3,745.5**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.3.5 Field Development Plan

2.3.5.1 BED 3

Recent (2019) drilling has further developed reservoirs in the Abu Roash C and G, in particular the discovery of unusually thick sandstone development at BED 3-23. New views of the sandstone distribution, combined with the complex set of fault splays at this stratigraphic level has opened further possible drilling locations (Figure 45). These target attic oil, possibly underexploited fault blocks and/or parts of sandstone fairways.

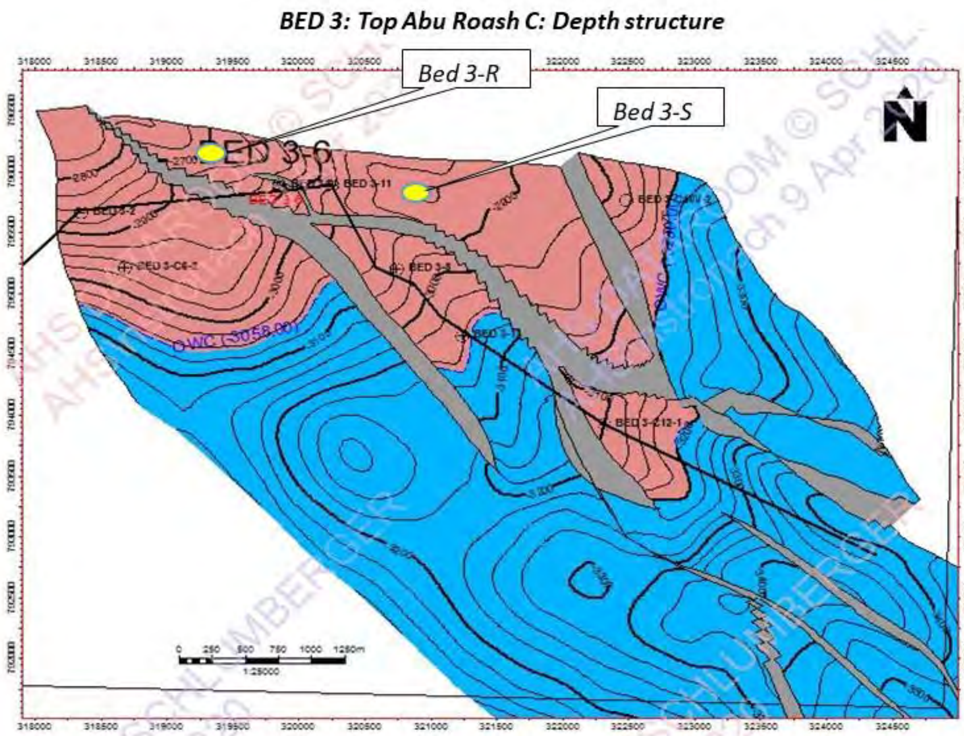
The Consortium's future development plans for BED 3 thus include the following activities:

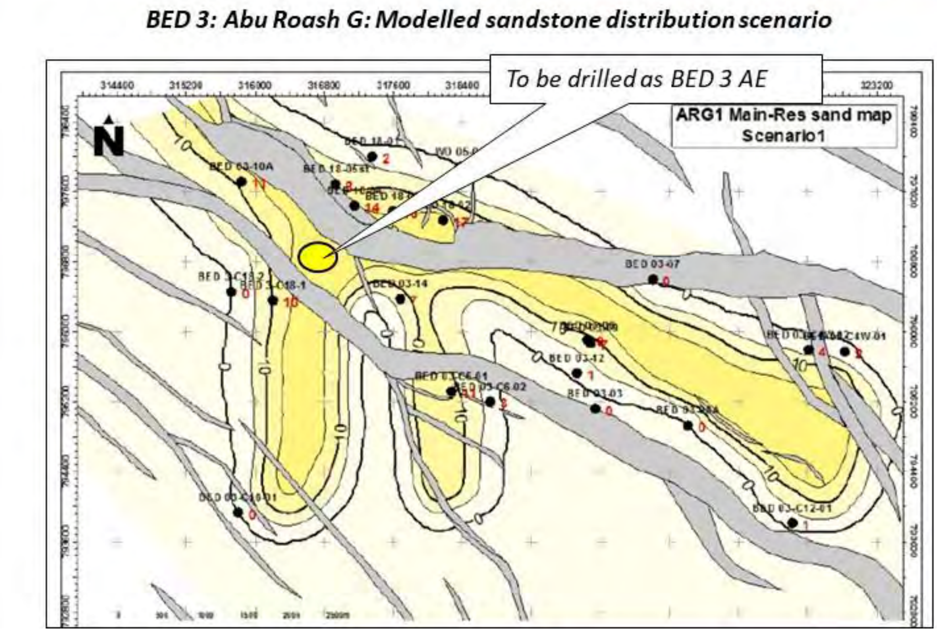
- One re-perforation plus four new infill wells are planned in the ARC. Of these, the Consortium has defined two locations in the BED 3-6 fault block in the Abu Roash C.
- Two new infills plus hookup of well BED 3-23 are planned in the ARG oil reservoir. Of these, one new location has been defined in the BED 3-C6 fault block in the Abu Roash G.
- The plan also includes one injector in the ARG (location AE), in the fault block containing well BED 3-18, and two in the ARC reservoir, the locations of which are yet to be confirmed.

Subsequent to the Effective Date of this report, in 1Q 2020, certain of the above activities have been completed, comprising:

- The completion and hook-up of BED 3-23 as a successful oil production well.
- Drilling of location BED 3 AE as well BED 3-24. Although understood ultimately planned to be used as injection support to wells BED 3-18 and BED 3-19, the well has initially been successfully completed as an oil well.

Figure 45: BED 3 Abu Roash Drilling Locations





Source: Vendor VDR

- No new firm wells are planned in the Kharita and Bahariya gas reservoirs.
- Three new wells to exploit upsides in the Bahariya gas reservoir are considered as Contingent Resources.

Although productive reservoir sweet spots occur, as at BED 3-14, reservoir quality is variable and much upside potential is attributed to successful targeting of low quality and "LRP" reservoirs. Studies have shown that these hydrocarbon volumes may be present, but the resources are at this stage considered contingent on definition of final drilling locations and demonstration of consistent productivity.

The schedule for the above activities has been defined in the Consortium's five year business plan. The drilling schedule is summarized in Table 51 and Table 52.

Table 51: BED 3 ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	1	0	0	0	**2**
Injection Wells	1	0	0	0	0	**1**
Total	**2**	**1**	**0**	**0**	**0**	**3**

Table 52: BED 3, ARC Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	4+1 re-perf	0	0	0	**5**
Injection Wells	0	2	0	0	0	**2**
Total	**0**	**7**	**0**	**0**	**0**	**7**

2.3.5.2 BED 15

The Consortium's future development plans for BED 16 include the following activities:

- Two new infill wells in the Kharita gas reservoir.

  Additional drilling is proposed to expand exploitation of the Kharita gas pool at BED 15. This involves 10 new wells in total, both in the main structure and in satellite fault blocks less well-defined with the available dataset. Only two wells are considered firm at this stage.

- Six new infill producers in the ARC and ARG reservoirs.

  As at BED 3, reconsideration of the latest understanding of sandstone distribution allows possibility of several new drilling locations in the Abu Roash. In this case, one location is currently specified as an updip attic target within the main Abu Roash C sandstone.

The drilling schedule is summarized in Table 53 and Table 54.

Table 53: BED 15, Kharita Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	2	0	0	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**2**	**0**	**0**	**2**

Table 54: BED 15, ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	6	0	0	0	**6**
Injection Wells	**0**	0	0	0	0	**0**
Total	**0**	**6**	**0**	**0**	**0**	**6**

2.3.5.3 BED 18

BED 18 consists of western and eastern areas, separated by a north-south oriented normal fault. Additional drilling is planned in the east for the Abu Roash G reservoir, where four production and two injection wells are planned. The key risks are both structural, in that the northern terrace of this area is not well-defined, and sedimentary, as the sand fairway appears oriented along the crest of the fault block, with the possibility of more marginal facies to the north. Subsequent to the Effective Date of this Report, in 1Q 2020, the first well, BED 18-15 has been completed. This confirmed the structural risks in this area, as it intersected a fault at Abu Roash G level. However, it was successfully completed as an oil producer in the Abu Roash E sandstone, thus opening a new hydrocarbon pool in the area.

The drilling schedule is summarized in Table 55.

Table 55: BED 18, ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	2	0	0	0	**2**
Injection Wells	0	2	0	0	0	**2**
Total	**2**	**2**	**0**	**0**	**0**	**4**

2.3.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (April 2026).

Table 56 and Table 57, show the remaining technically recoverable gas and oil volumes for the BED 3 cluster.

Table 56: Remaining Technically Recoverable Gas Volumes, BED 3 Cluster, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
BED 3	29.6	36.3	43.1
BED 15	7.9	14.9	22.4
BED 18	0.1	0.6	1.2
SI Re-activation	13.1	13.8	14.5
Total	**50.7**	**65.6**	**81.2**

Notes:

1. The volumes in this table are to the end of April 2026; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 57: Remaining Technically Recoverable Oil and Condensate Volumes, BED 3 Cluster, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
BED 3	6.1	8.4	10.8
BED 15	2.2	3.7	5.5
BED 18	1.1	1.9	3.0
SI Re-activation	1.5	1.6	1.7
Total	**10.9**	**15.6**	**21.0**

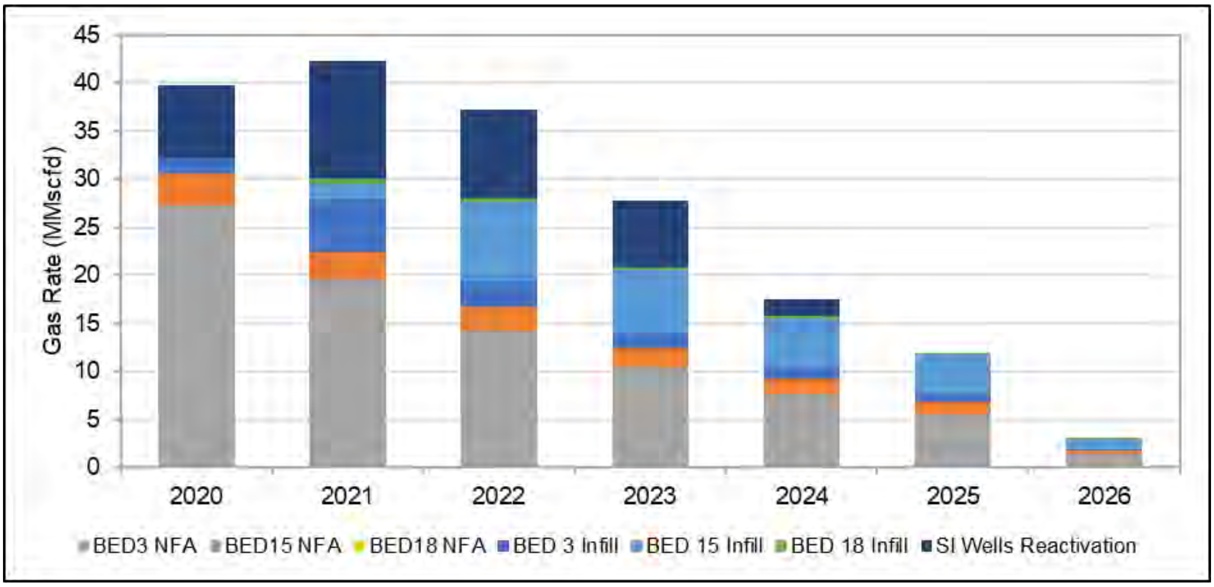
Notes:

1. The volumes in this table are to the end of April 2026; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 46 and Figure 47 show the gas and oil production forecasts for the BED 3 cluster by activity.

Figure 48 and Figure 49 show the Low, Best and High production forecasts for the BED 3 cluster.

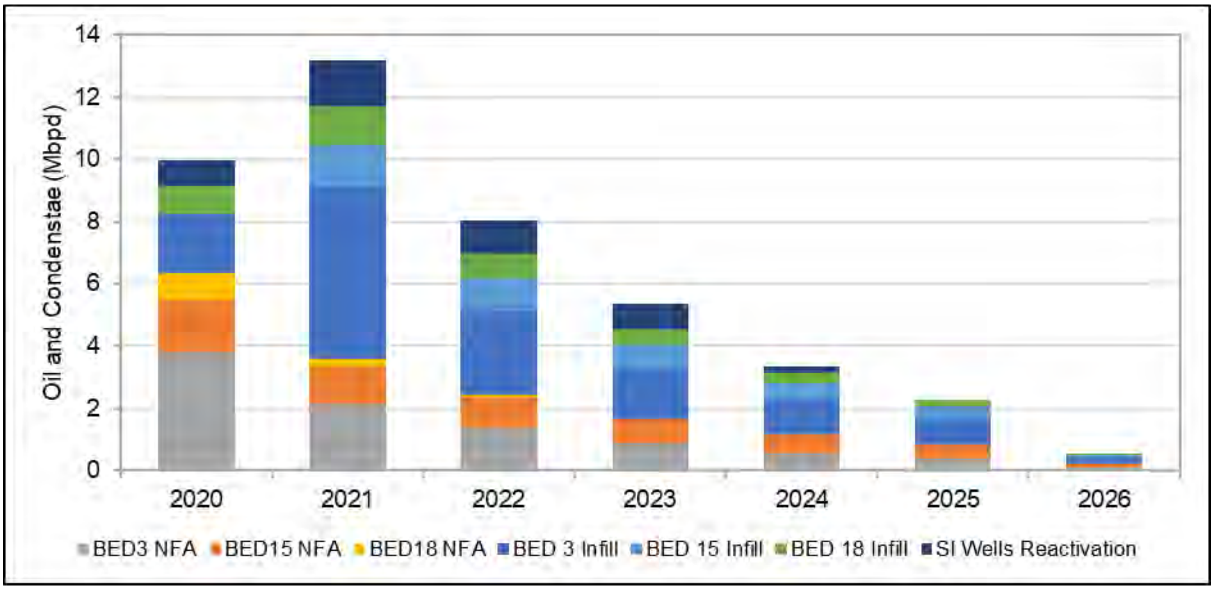
Figure 46: Best Case Gas Production Forecasts, BED 3 Cluster



Notes:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

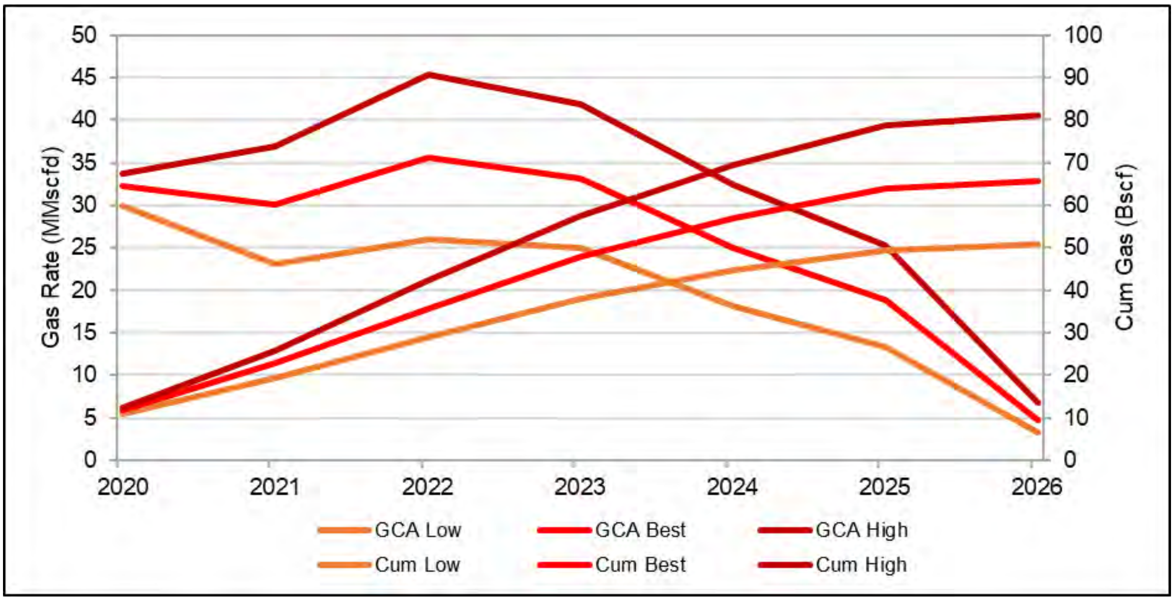
Figure 47: Best Case Oil and Condensate Production Forecasts, BED 3 Cluster



Note:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.

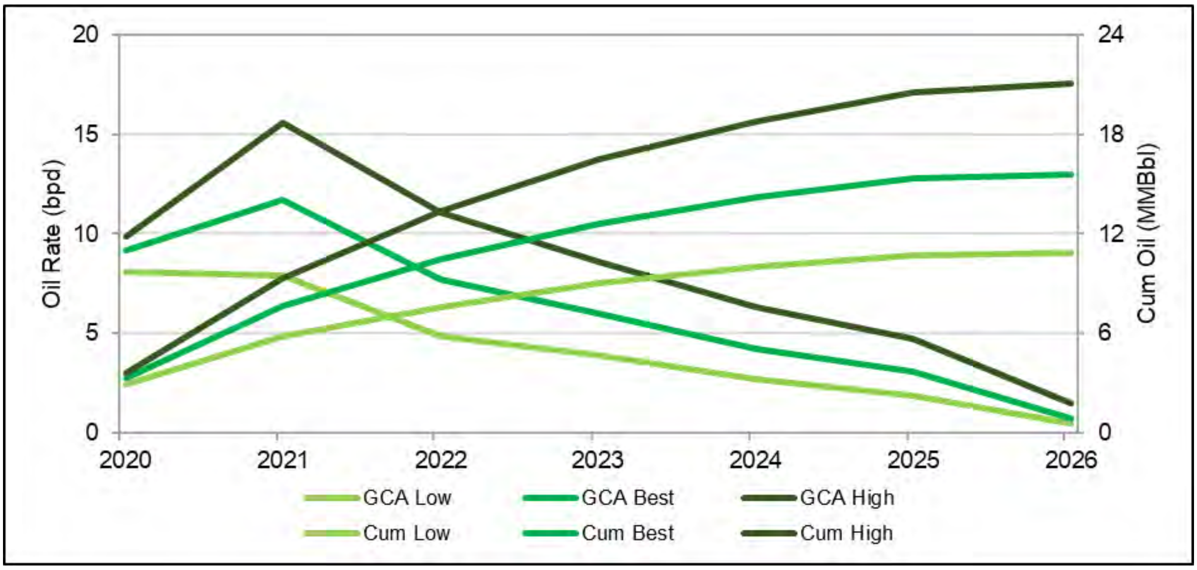
Figure 48: Gas Production Forecasts, BED 3 Cluster



Notes:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 49: Oil and Condensate Production Forecasts, BED 3 Cluster



Note:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.

2.3.7 Contingent Resources

Contingent Resources were assigned to wells for which locations have not yet been defined and where significant further modelling work is required to bring to these opportunities to a higher level of confidence.

The incremental production form three wells in the BED 3 Bahariya gas are considered as Contingent Resources. The incremental production of an additional eight infill producers in the BED 15 Kharita gas was also considered as Contingent Resources.

The BED3 Contingent Resources are summarized in Table 58.

Table 58: Gross Contingent Resources, BED 3 Cluster, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
BED3 Bahariya Gas	1.9	4.0	6.3
BED15 Kharita Gas	11.5	24.1	40.0
Total	**13.4**	**28.1**	**46.3**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
BED3 Bahariya Gas	0.0	0.1	0.1
BED15 Kharita Gas	0.2	0.5	1.0
Total	**0.2**	**0.6**	**1.1**

Notes:

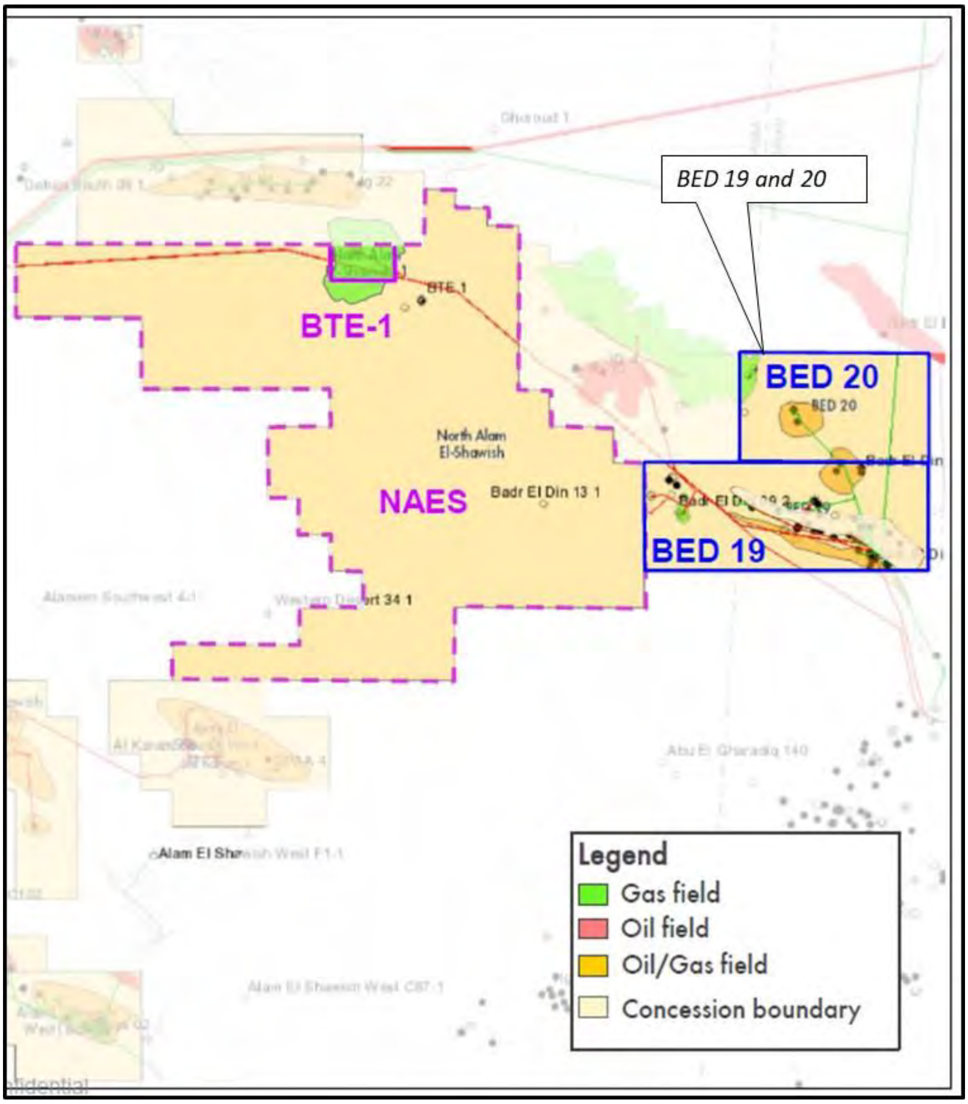
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.4 BED 19/20 Cluster

2.4.1 Asset Description

The BED 19/20 cluster, consists of the BED 19 and BED 20 development leases, located approximately 35 km to the east of BED 16 (Figure 50).

Figure 50: BED 19/20 Cluster Location Map



Source: Vendor VDR

2.4.1.1 *Structure and Trap*

The BED 19 and 20 structures are elongate structural traps with dip closure to the NE of down-to-the-SW normal faults. Trapping in the shallow plays is provided by dip-closed drape over underlying fault blocks.

2.4.1.2 *Reservoir*

Principal oil-bearing reservoirs are in the Lower Cretaceous Alam el Buieb sandstones, but with an emerging volatile oil play in the Jurassic Safa Formation, proved by the BED 20 J2-1 well. There is in addition a tight chalk play in the Upper Cretaceous Khoman Formation (oil) in BED 19, and in the pool immediately to the west, designated BED 9 for gas in the Cenozoic Apollonia Formation (gas).

2.4.1.3 Reservoir and Fluid Properties

No specific PVT data are available for the BED 19/20 area wells. Refer to the examples in the BED 3 dataset for illustrative information.

2.4.1.4 Production Facilities

Gas production is via the existing BED 19 line to the BED 3 processing plant (see section 2.3).

2.4.2 HIIP

As BED 19 and BED 20 were not prioritized for active development in the Consortium plans, HIIP has not been closely examined by GaffneyCline. The volumes reported by the Vendor are as in Table 59 and Table 60.

Table 59: BED 19/20 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			
			Low	Best	High	Notes
BED 19	Vendor exploration overview	Khoman	7.5	14.2	21.7	Total HIIP attributed to two potential prospects
		Alam el Buieb				Not reported
BED 20-2	Vendor "CRIN", 2019	Alam el Buieb	5.3	7.5	10.4	Total for A2, A3, A4 and B sands
BED 20 J2-1	Vendor "CRIN", 2019	Safa and Kabrit Formations	2.4	10.5	24.9	

Table 60: BED 19/20 Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			
			Low	Best	High	Notes
BED 19 (BED 9)	Consortium after Vendor static model (2013)	Apollonia A5	54	75	109	GaffneyCline has validated estimates. Those for C12 assume optimum reservoir development.
		Apollonia C12	64	189	261	
BED 20 J2-1	Vendor "CRIN", 2019	Safa and Kabrit Formations	4.4	19.1	49.8	Gas associated with volatile oil

2.4.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 61.

As can be seen, after evaluation, no Reserves or Contingent Resources were attributed by the Consortium to the Best Case plan described here.

Table 61: BED 19/20: Resource Categories in Databook

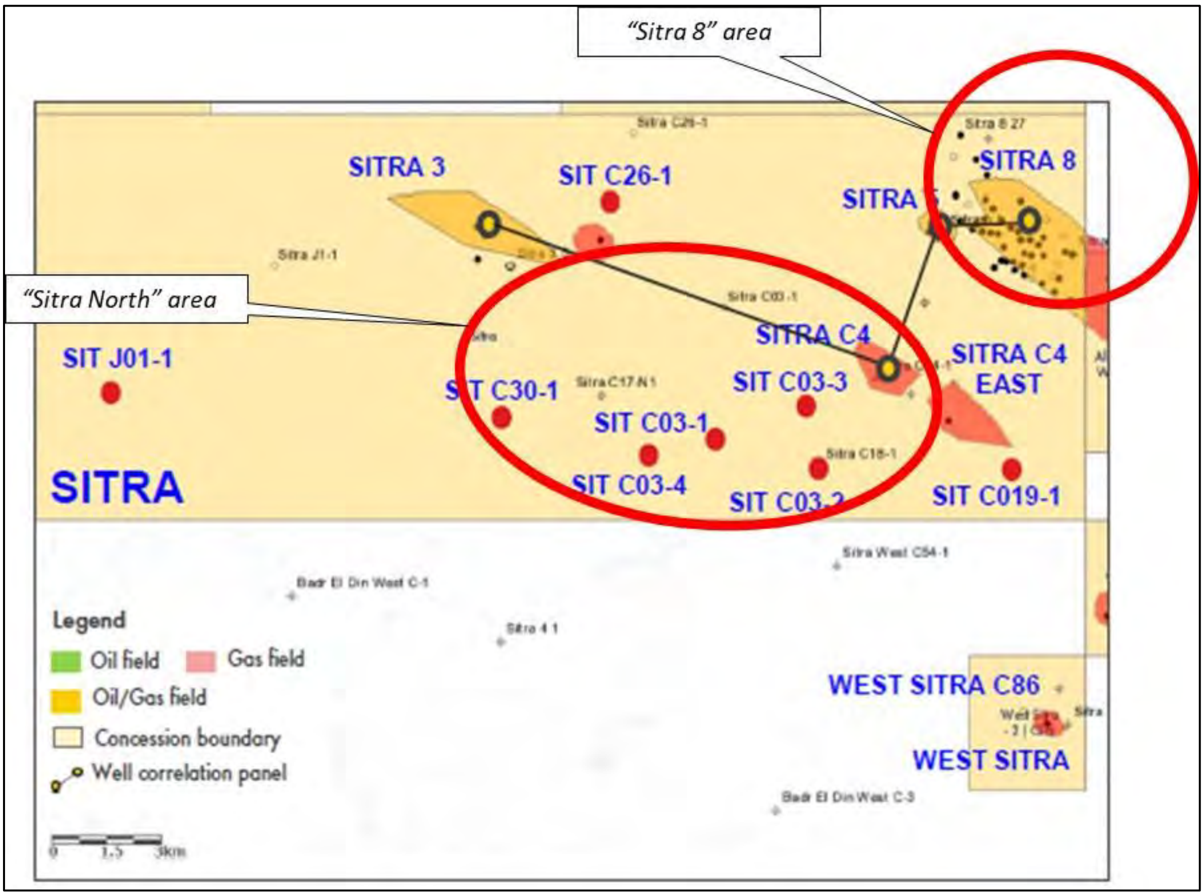
Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Notes
BED 9 NFA	Not included	Minor activities with insufficient materiality	N/A
BED 19 NFA	Not included		N/A
BED 20 NFA	Not included		N/A
General NFA	Not included		N/A
BED 20 infill	Not included	Further Alam el Bueib development. Not viewed as sufficiently material.	N/A
BED 19 C2E	Not included	Principally recovery of gas and oil from tight chalk plays (Apollonia and Khoman Formations)	**Contingent Resources**. Apollonia gas resources evaluated, but not viewed as part of key forward plan.
BED 20 C2E	Not included	Includes additional Alam el Buieb prospects and development of Safa Formation discovery (BED 20 J-1)	**Contingent Resources and Prospective Resources**. Awaiting further appraisal to finalise development plan.
Upside	Not included	No other upside defined	N/A

2.5 Sitra

2.5.1 Asset Description

The Sitra contract area contains a number of fields. The areas of focus here are Sitra 8 and the Sitra North cluster (Figure 51).

Figure 51: Sitra Fields Location Map



Source: Vendor VDR

2.5.1.1 Structure and Trap

Sitra 8 is a well-established field comprising stacked reservoirs in a closure controlled by the footwall of a major NW-SE normal fault. It is dip-closed to the NE. The North Sitra cluster is controlled by a major NW-SE trending normal fault which changes to a more E-W orientation in the east, along with various splays to create a number of individual closures. Of significance here are the Sitra 3/C30 closure and the C3 group, to the east.

2.5.1.2 Reservoir

Oil-bearing reservoirs at Sitra 8 occur in the Abu Roash Formation C, E and Upper G Zones, and in the Upper Bahariya. The Lower part of the Abu Roash G Zone is gas-bearing, as is the Lower Bahariya Formation. A full static model is available for Sitra 8, and this shows optimum sand development in the Abu Roash G reservoir over the crest of the field. Sitra 5 is a fault block immediately to the west of Sitra 8, but contains only smaller volumes of oil in Abu Roash C zone and Lower Bahariya, and gas in the Upper Bahariya Formation.

Although Abu Roash reservoirs are hydrocarbon-bearing at North Sitra, of greater significance here are oil and gas-bearing reservoirs in the Bahariya Formation.

2.5.1.3 Reservoir and Fluid Properties

Representative PVT samples are presented in Table 62. Reported CO_2 content is low, at 1.19 mol% in the Kharita Formation. Pressure and temperature gradients are normal.

Table 62: Sitra Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Sitra 3-2ST1	KHA	3,045	108.3	4,200	4,150	Not known	100	0.03	0.65

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
Sitra 3-1	BAH	Not known	107.2	4,264	4,045	1.63	861	Not known	40
Sitra 5-1	BAH	3,175	116.1	4,759	4,508	1.46	870	Not known	32
Sitra 8-4	ARE	2,880	114.1	4,438	2,248	1.41	740	Not known	39
Sitra 8-6	ARG	3,210	126.9	4,886	1,378	1.25	369	Not known	31

2.5.1.4 Production Facilities

The production fluids from Sitra are processed by the Sitra Early Production Facility, which separates the oil, gas and produced water before the oil and gas are exported via pipeline to the BED 3 processing plant for further treatment (see section 2.3). The Sitra produced water is then disposed of via evaporation ponds. The Sitra EPF is designed to treat 12 MBbl/day of condensate.

The Sitra EPF will be mothballed during 2020, on completion of the BED 3 produced water reinjection project. Sitra fluids will then all be separated and treated at the BED 3 processing plant.

2.5.2 HIIP

GaffneyCline has reviewed the Vendor's petrophysical interpretation and static models for the Sitra 8 field, which has allowed validation of the HIIP quoted by the Vendor. Final HIIP estimates are presented in Table 63 and Table 64. For other fields, a Vendor resource evaluation (the so-called Contingent Resource Information Note or CRIN) has been broadly validated by GaffneyCline's work.

Table 63: Sitra Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
Sitra 8	**Vendor IM**	Abu Roash C	-	34	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Abu Roash E	-	17	-	
		Upper Abu Roash G	-	39	-	
		Upper Bahariya	-	74	91	Static model describes 91 MMBbl, based on inclusion of more marginal reservoir facies.
Sitra 5	**Vendor IM**	Abu Roash C	-	7	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Lower Bahariya	-	9	-	
Sitra 3/C30	**Vendor Sitra "Mega CRIN"**	Lower Bahariya and Kharita Formations	-	12.6	-	Oil rim. See additional volumes in gas leg in Table 64.
Sitra C3E		Bahariya Formations	-	8.3	-	Minor additional condensate in Abu Roash G.

Table 64: Sitra Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			Notes
			Low	Best	High	
Sitra 8	Vendor IM	Lower Abu Roash G	-	20	-	Value as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Lower Bahariya	-	181	278	High Case reflects uncertainty seen in analysis of field extent and reservoir definitions in static model.
Sitra 5		Upper Bahariya	-	25	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
Sitra 3/C30	**Vendor Sitra "Mega CRIN"**	Lower Bahariya and Kharita Formations	-	82.9	-	Gas leg. See additional volumes in oil rim in Table 63.

2.5.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 65.

Table 65: Sitra: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
Sitra 8 NFA	Sitra NFA	All categories amalgamated, with focus on Sitra 8 as the largest active field	**Reserves**
Sitra 5 NFA			
Sitra C4 NFA			
Sitra 3 NFA			
Sitra C3 NFA			
Sitra C10/30 NFA			
General NFA			
Sitra 8 Infill	Sitra 8 Infill	Well infill programme in Sitra 8 field	**Reserves**
Sitra C18 infill	Not included	Reactivation of small discovery at Sitra C18-1	Minimal associated reserves and no expenditure committed in Consortium plan.
Sitra 1 infill	Not included	Reactivation of small discovery at Sitra 1-1	Minimal associated reserves and no expenditure committed in Consortium plan.
Sitra C10/C30 infill	Sitra 3 plus C30 infill	Major North Sitra infill programme at both Sitra 3/C30 and at C03E	**Reserves** at Sitra 3/C30. Sitra C10-1 is a dry hole whose location is unclear from the VDR data.
	Sitra C03 infill		
Sitra C2E	Not included	Other activities at Sitra C-19, C-26 and J-01	**Prospective Resource**
Sitra Upsides	Not included		

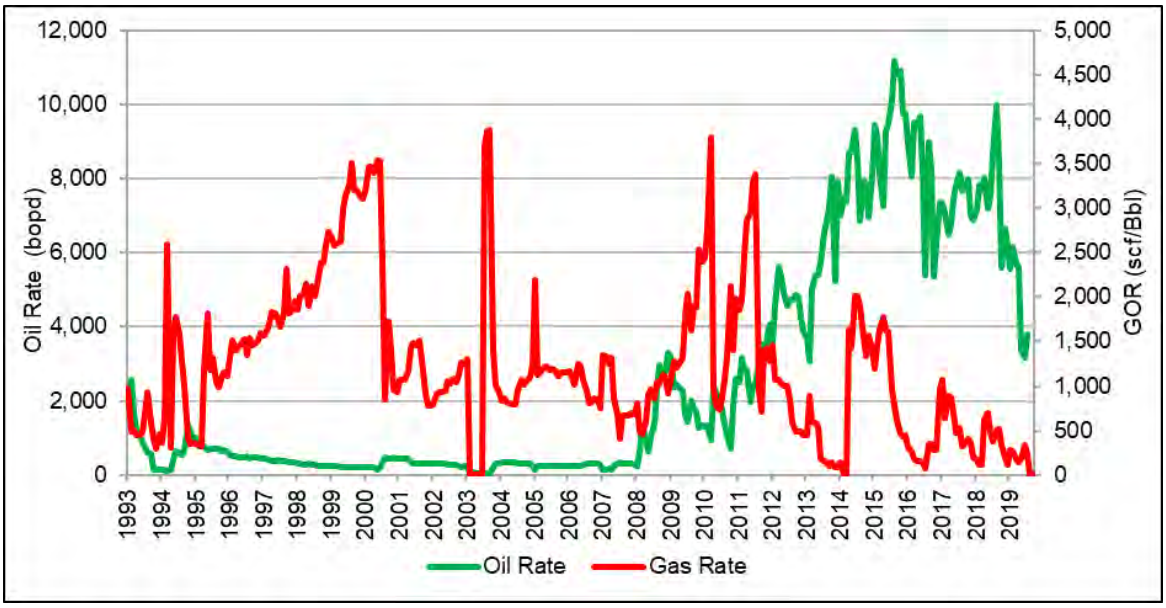
2.5.4 Historical Field Performance

2.5.4.1 Sitra 8

Production in Sitra 8 commenced in 1993 with the Sitra 8-1B well producing from the ARG Upper and ARG Lower commingled with the ARC. There was no drilling between 1994 and 2007. In 2008, appraisal and development wells were drilled in the area. In 2010, production increased form 150 bpd to 1,750 bpd as a result of 5 appraisal wells.

In 2010, 3 new wells were drilled and the oil rate reached 5,800 bpd in August 2012. In 2012, water injection began. The current oil production is approximately 1,500 bpd with an average water cut of 9% and an average GOR of 260 scf/Bbl. Figure 52 shows the historical oil production and GOR for Sitra 8.

Figure 52: Historical Oil Production Rate and GOR, Sitra 8



2.5.4.2 *Sitra North (Sitra 3, Sitra C3 and Sitra C30)*

Sitra North was discovered in 1982 by the Sitra 1-1 well. Production from the Bahariya formation started in 1990 using the Sitra 3-1 well but this was shut in a year later. Production restarted in 2015, and Sitra 3-4 and Sitra 3-5 commenced production in 2018. Sitra C30 started production from the Bahariya formation in 2019 with two wells, Sitra C3-1 and C3-2.

Figure 53 shows the historical oil and gas production for Sitra North and the historical production performance is summarized in Table 66.

Figure 53: Historical Oil and Gas Production Rate, Sitra North

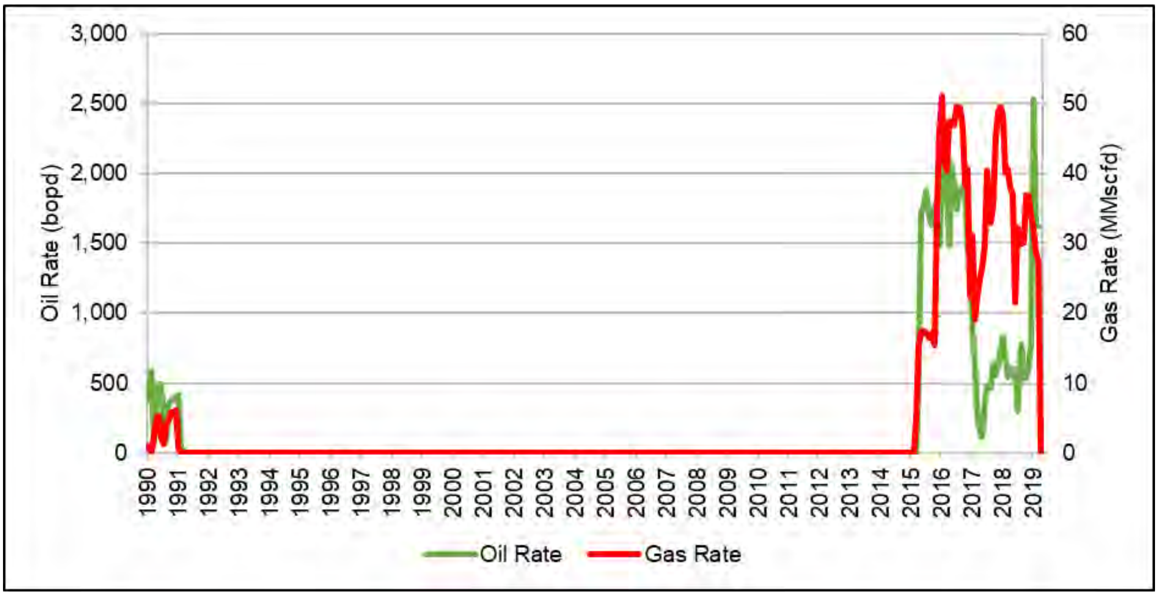


Table 66: Sitra Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate in 4Q 2019	Average Gas Rate in 4Q 2019	Average Water Rate in 4Q 2019
		MMBbl	Bscf	bopd	MMscfd	bwpd
Sitra 3	5	0.3	51.1	407.1	28.2	39.0
Sitra 5	1	1.6	3.2	83.0	0.0	220.5
Sitra 8	16	24.7	21.3	3,972.5	0.9	4,552.0
Sitra C4	1	0.8	0.2	382.6	0.0	1.0
Sitra C26	1	0.1	0.1	276.4	0.4	192.5
Sitra C3	1	0.1	0.4	904.4	2.3	40.3
Total	**25**	**27.6**	**76.1**	**6,026.0**	**31.8**	**5,045.3**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.5.5 Field Development Plan

2.5.5.1 Sitra 8

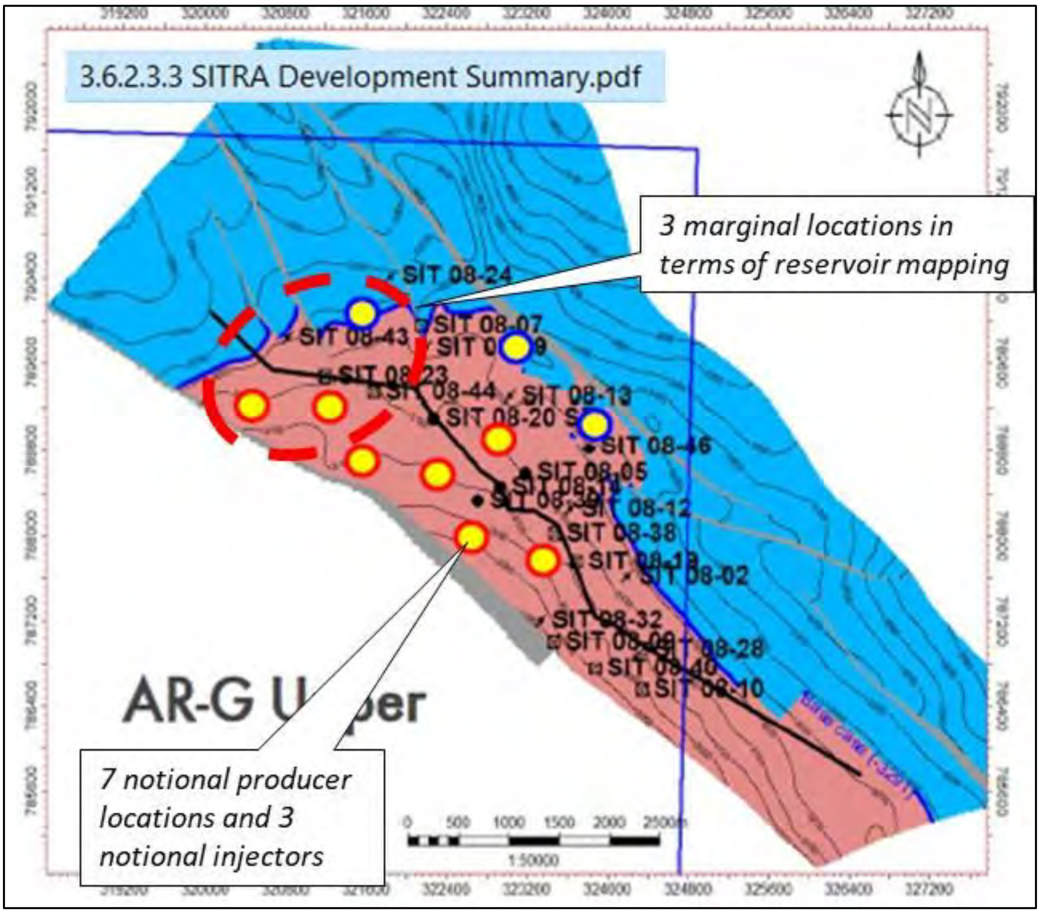
The Consortium's development plans for the Sitra 8 field include fourteen new infill oil producers in the Sitra 8 area, of which two infill wells are to be drilled in 2020, and five new injectors to be drilled in 2021, with the largest number for the Abu Roash G:

- Abu Roash C: 2 producers plus 1 injector;
- Abu Roash E: 1 producer;
- Abu Roash G Upper: 7 producers plus 3 injectors;
- Abu Roash G Lower (Gas): 1 producer; and
- Upper Bahariya (Sequence 3): 4 producers plus 1 injector.

Locations are not finalised but GaffneyCline accepts that this plan is feasible and that there is sufficient calibration of the reservoir model to be able to confidently locate this number of wells.

For the Abu Roash G, GaffneyCline has conducted a closer review. The bulk of the HIIP (40%) is within the uppermost ARG 0-1 unit, as this appears to cover the crestal part of the field, but also to extend south and north. The Vendor proposed 10 locations but this would require siting wells on the flanks, where the sandstone is less well demonstrated although there has some success, for example at the injection well at Sitra 8-46. GaffneyCline accepts that 7 locations can be considered as relatively low risk (Figure 54).

Figure 54: Sitra 8: Proposed Well Locations, Abu Roash G Zone



Source: Vendor VDR

The drilling schedule is summarized in Table 67.

Table 67: Sitra 8 Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	6	6	0	0	**14**
Injection Wells	0	2	3	0	0	**5**
Total	**2**	**8**	**9**	**0**	**0**	**19**

2.5.5.2 Sitra North

The Consortium's future development plans for the Sitra North fields include the following activities:

- One vertical gas well in C30 area to be drilled in 2020.

  The well is to be sited on the crest of the structure, NW of well Sitra C30-1, in a relatively low risk location, between the Sitra 3 and C30 areas.

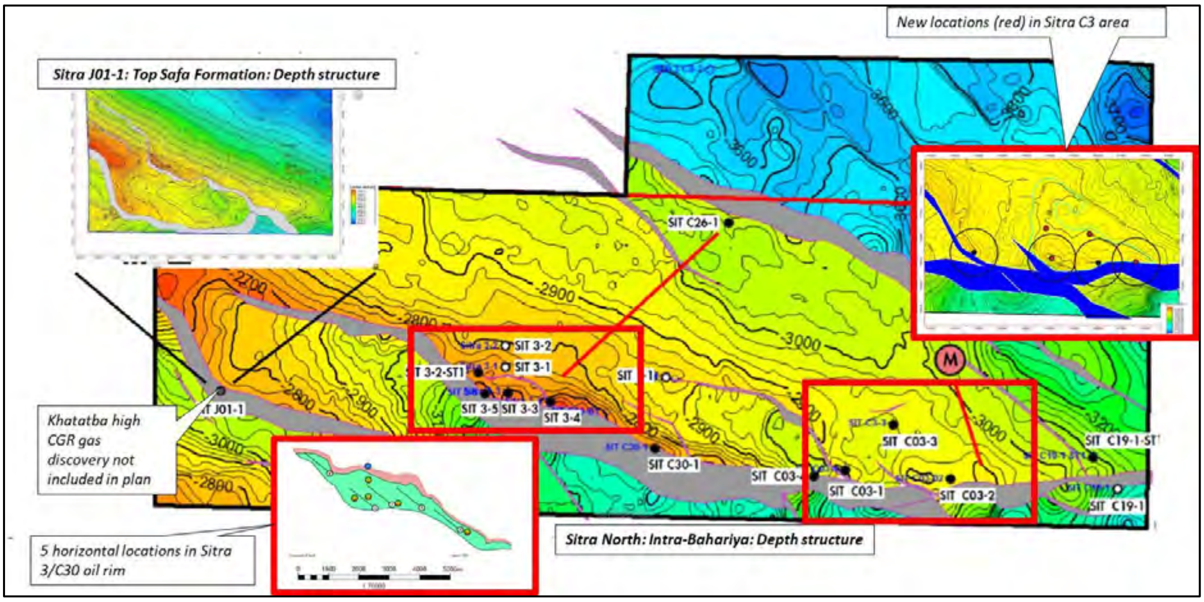
- Vertical wells in the C3 area.

Four wells are to be located in the Sitra C3E pool (Figure 54), which is the largest of this group of pools. There is some uncertainty over structure, position of the wells with respect to the position of the OWC on the lower relief northern terrace, and reservoir continuity.

- Horizontal wells in the Sitra 3 oil rim.

  In addition to the further development of the gas pool in the Bahariya/Kharita Formations at Sitra C30, it is understood from discussions with the Consortium during the vPDR process that the focus of future drilling in the Sitra 3/C30 field is on exploiting the oil rim within the Bahariya and Kharita Formations. This is an 18-25 m thick column that straddles the Lower Bahahriya and Kharita Formations beneath the thicker gas leg. GaffneyCline has not been able to evaluate this in detail, but can see support for the 5 horizontal well locations that are notionally proposed (Figure 55). Detailed siting of wells within the variable sandstone facies of the Lower Bahariya may prove challenging.

Figure 55: North Sitra: Proposed Well Locations



Source: Vendor VDR

The drilling schedule is summarized in Table 68.

Table 68: Sitra North Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	7	2	-	-	**10**
Injection Wells	-	-	-	-	-	**0**
Total	**1**	**7**	**2**	**-**	**-**	**10**

There is in addition a deep discovery in the Jurassic (Sitra J01-1) that is considered as a high risk development and is not considered further here.

2.5.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (1st December 2025).

Table 69 and Table 70, shows the remaining technical recoverable volumes for the Sitra 8, Sitra 3, Sitra C3 and Sitra 30 fields.

Table 69: Remaining Technically Recoverable Gas Volumes, Sitra, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
Sitra NFA	21.8	25.7	29.2
Sitra 8	0.5	2.6	6.0
Sitra 3 & C3 Infill	0.5	1.0	1.8
Sitra 30 Infill	2.0	4.3	7.3
SI Wells Re-activations	0.1	0.1	0.1
Total	**24.9**	**33.7**	**44.4**

Notes:

1. The volumes in this table are to the end of November 2025; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 70: Remaining Technically Recoverable Oil and Condensate Volumes, Sitra, as at 31st December 2019

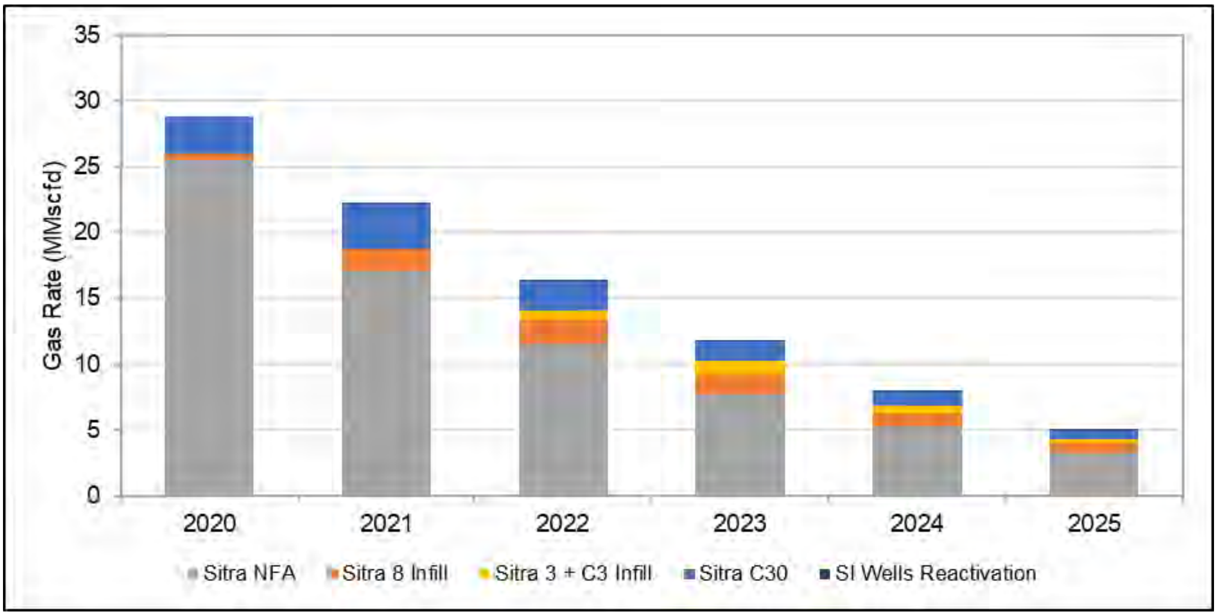
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Sitra NFA	3.9	4.7	5.4
Sitra 8	1.7	4.5	7.4
Sitra 3 & C3 infill	1.2	2.3	4.0
SI Wells Re-activations	0.4	0.4	0.4
Total	**7.2**	**11.9**	**17.2**

Notes:

1. The volumes in this table are to the end of November 2025; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 56 and Figure 57 shows the gas and condensate forecasts for the Sitra area Best case.

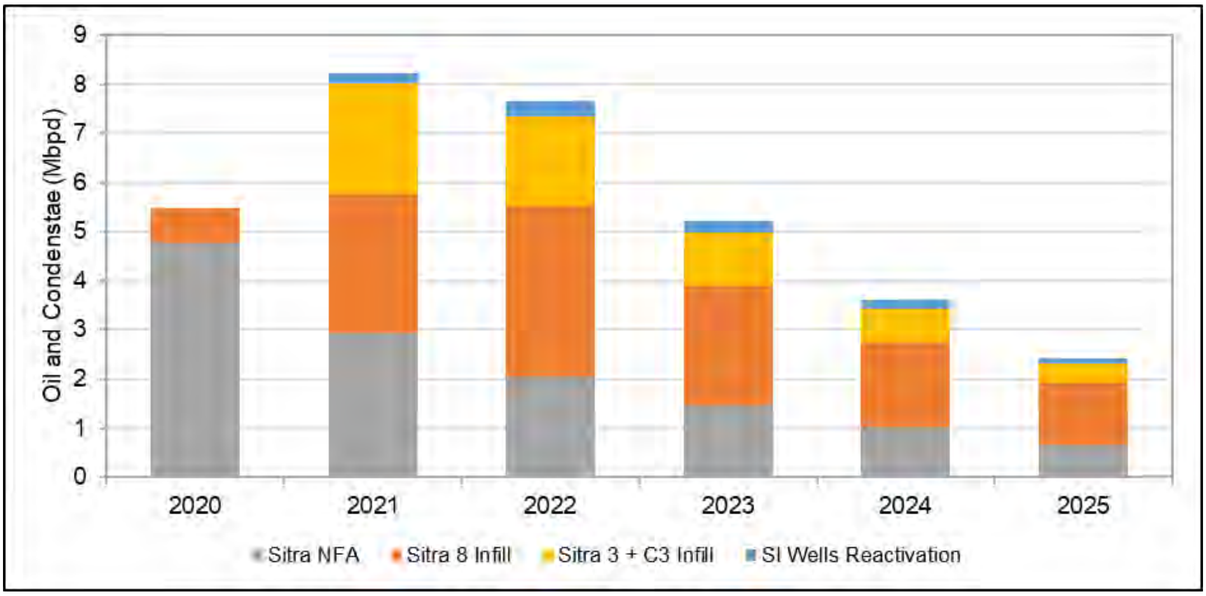
Figure 56: Best Case Gas Production Forecast, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 57: Best Case Oil and Condensate Production Forecast, Sitra

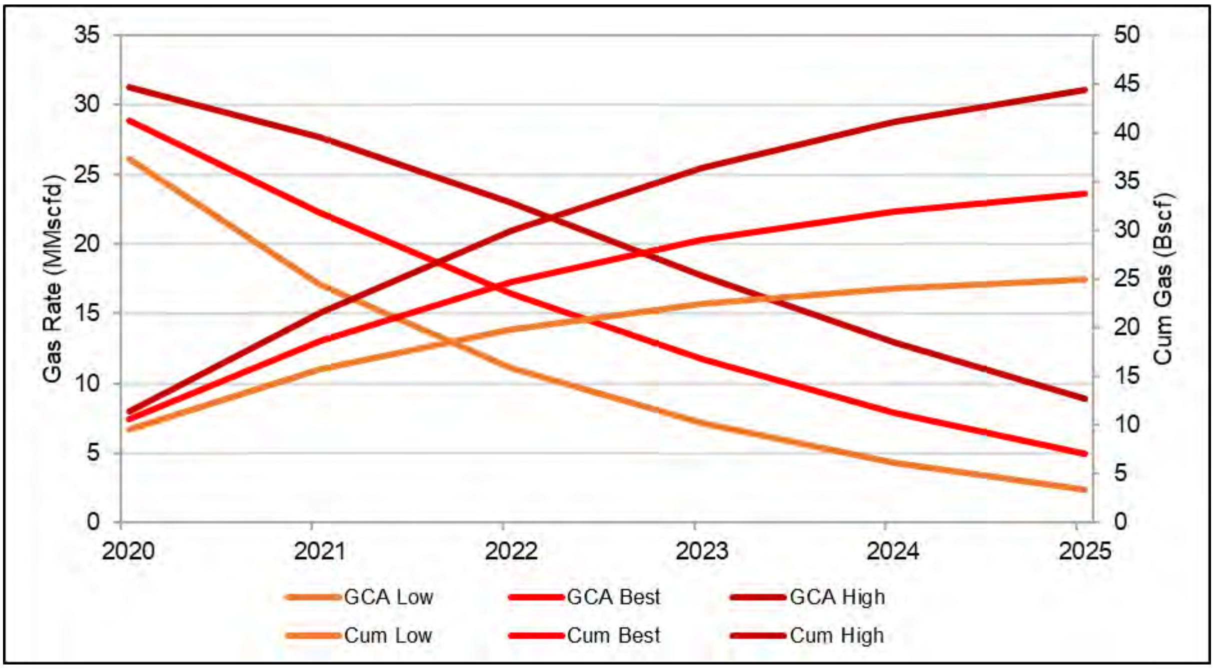


Note:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.

Figure 58 and Figure 59 show Low, Best and High forecast production profiles for Sitra area.

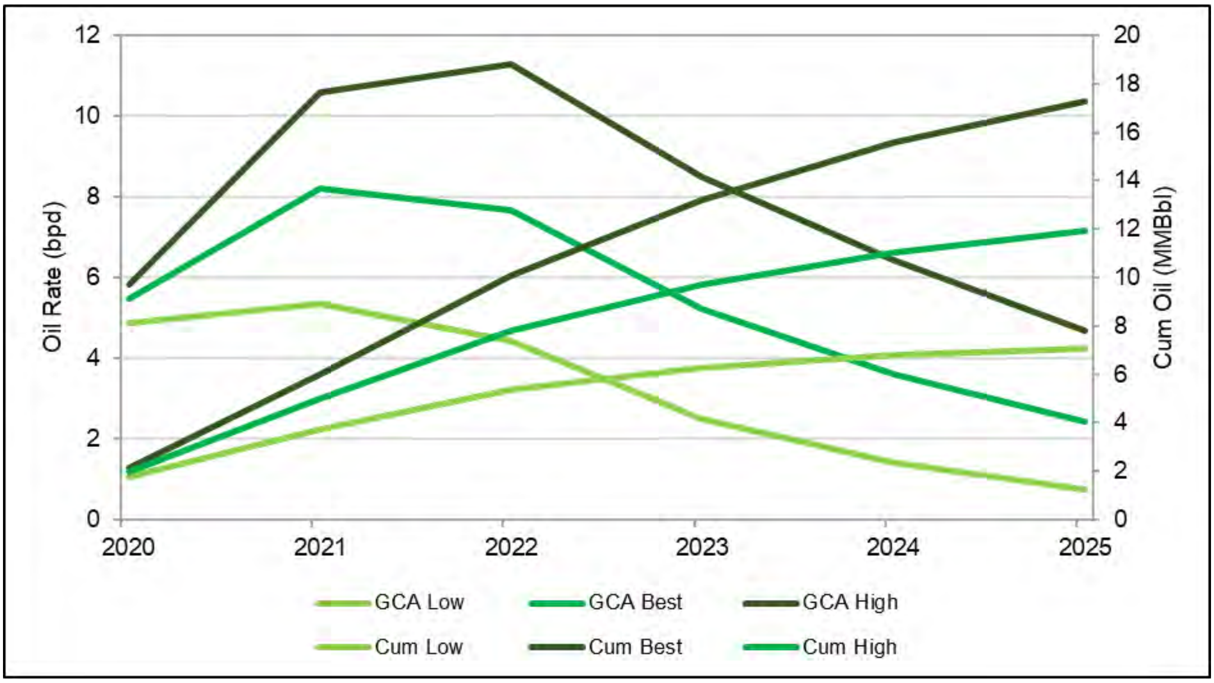
Figure 58: Gas Production Forecasts, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 59: Oil and Condensate Production Forecasts, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

2.5.7 Contingent Resources

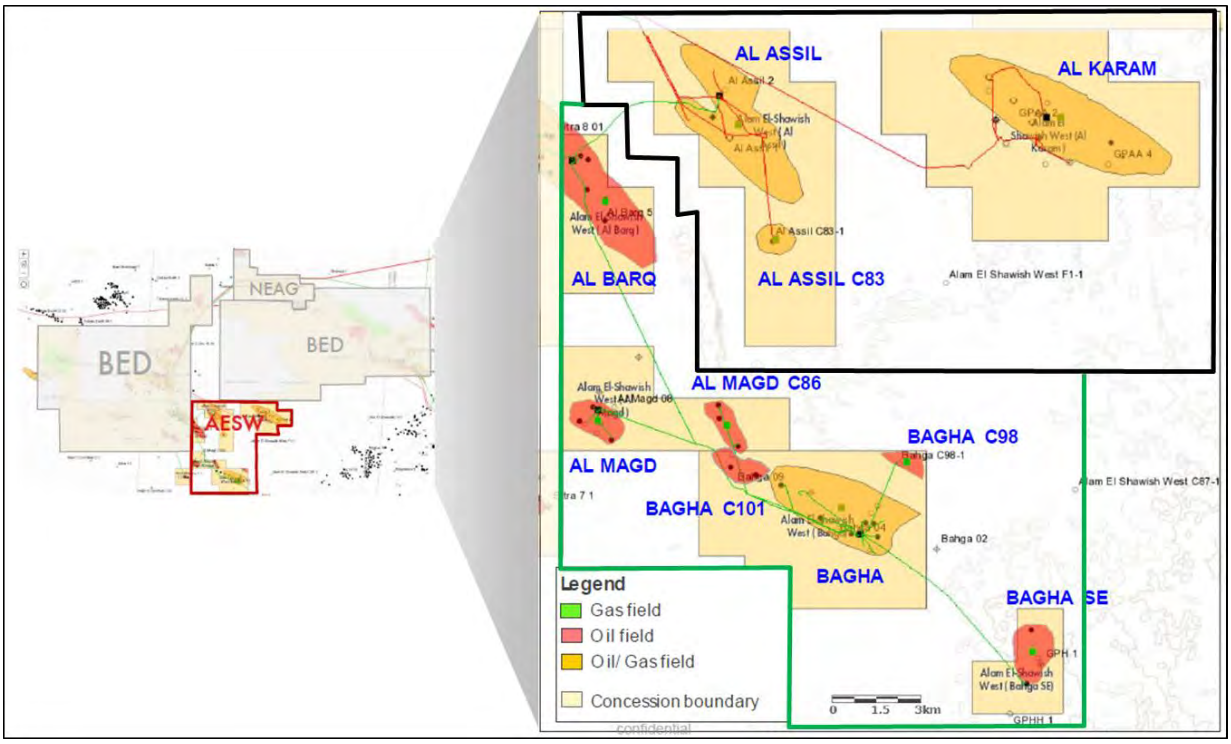
No Contingent Resources were assigned to this asset.

2.6 Alam El Shawish West (AESW)

2.6.1 Asset Description

AESW is composed of 10 fields, which are broken up into two general areas. The Assil Field and its satellite (C83) and the Al Karam Field make up the northern area. The southern AESW area is comprised of the Al Barq, Al Magd and Bagha Fields and their satellites. All of the fields and satellites are located within a relatively well constrained area of approximately 20 km by 18 km. Figure 60 presents a location map of the fields and satellites in AESW.

Figure 60: AESW Location Map

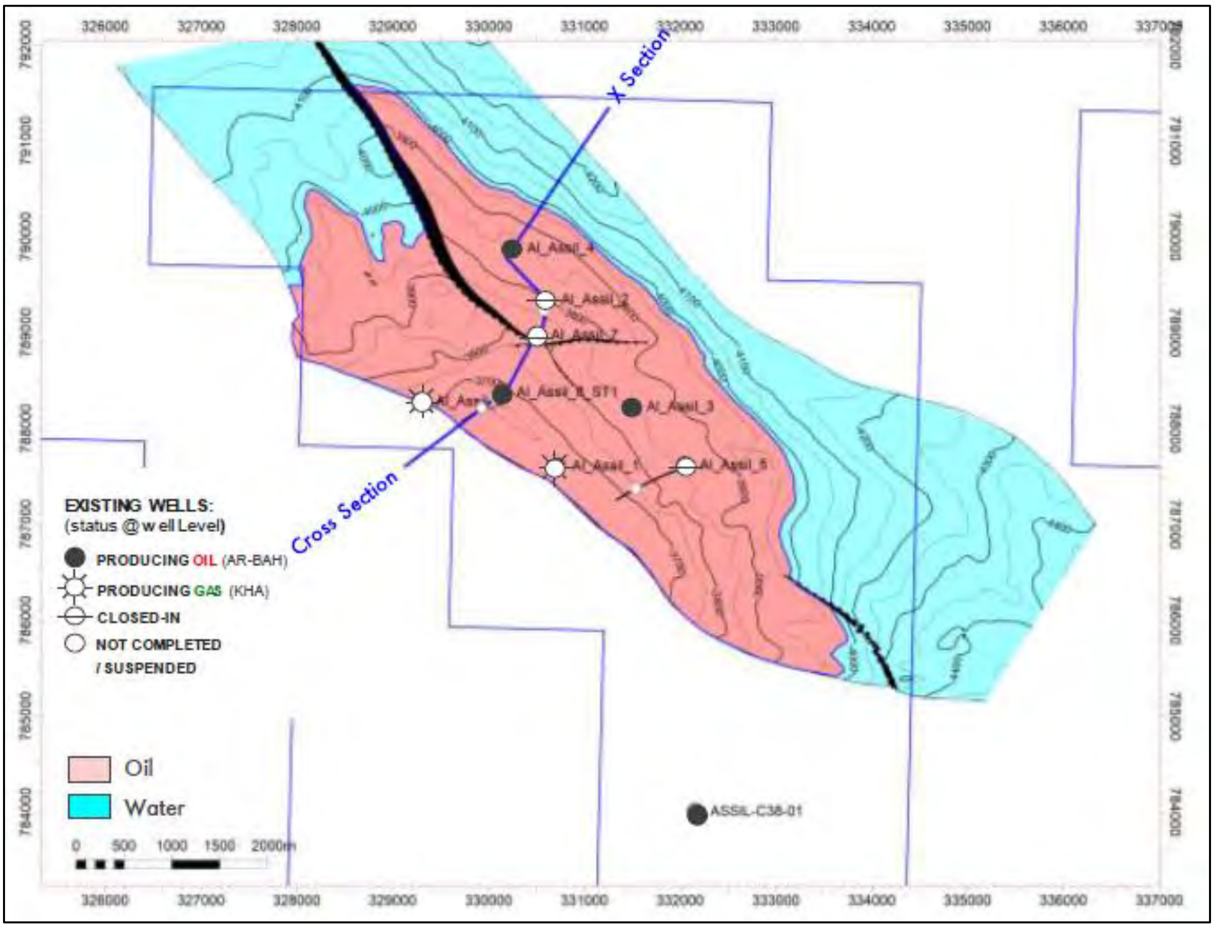


Source: Vendor IM

At Assil and Al Karam the development of the Kharita gas reservoirs has been the focus to date. Up to January 2019, a combined 338 Bcf of gas has been produced from the Kharita reservoirs. The short term future focus at Assil and Al Karam is the development of the larger oil reservoirs through water flood and infill drilling of the gas reservoirs.

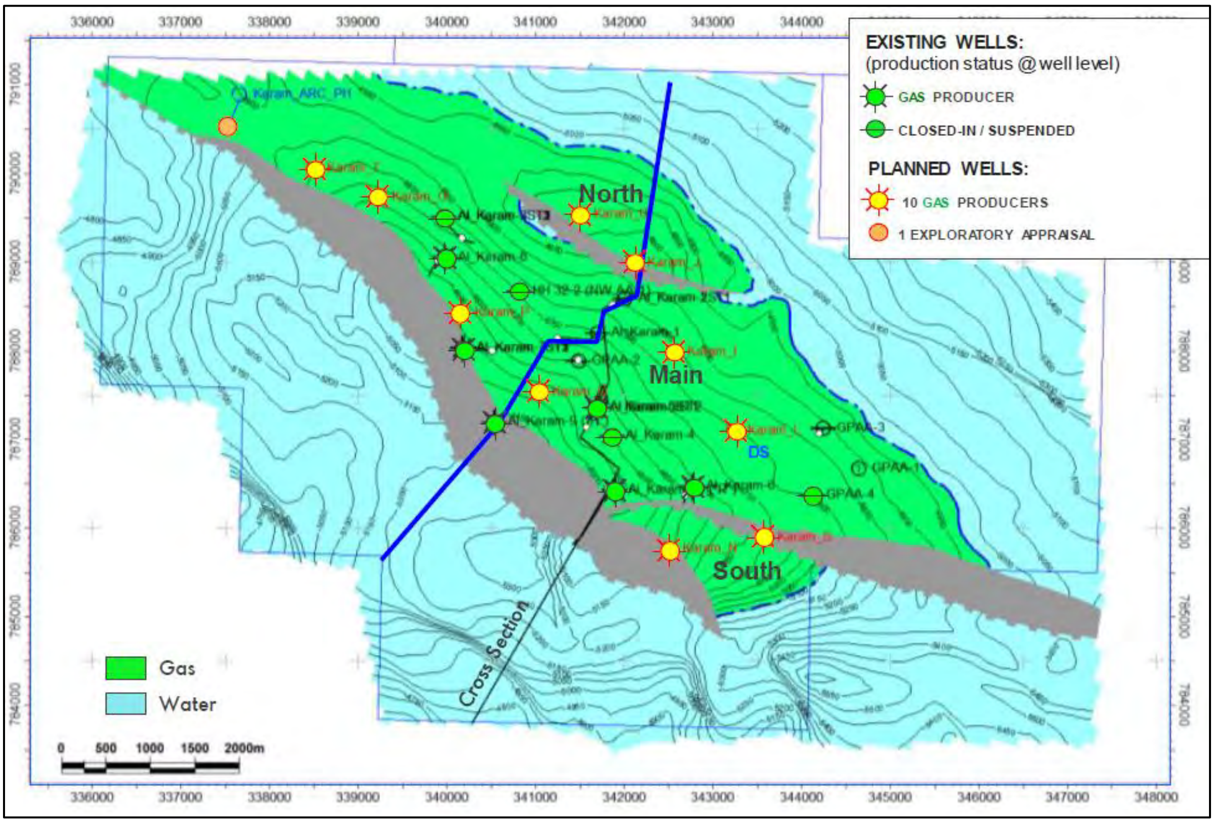
Assil and Al Karam are both fault bound (to the south), 3-way dip closed structures, which are elongate in a NW to SE orientation. The Assil primary reservoir is the Bahariya, which lies at a depth of approximately 3,800 mTVDss. The primary reservoir at Al Karam is the Kharita, which is situated at approximately 4,860 mTVDss. Drilling has generally focused on the structural crests, but the near term wells are targeted at drilling more of the un-drilled areas. Figure 61 and Figure 62 present structural maps of the Assil and Al Karam Fields respectively.

Figure 61: Assil Structural Configuration – Bahariya Reservoir Level



Source: Vendor VDR

Figure 62: Al Karam Structure Map – Kharita Reservoir Level



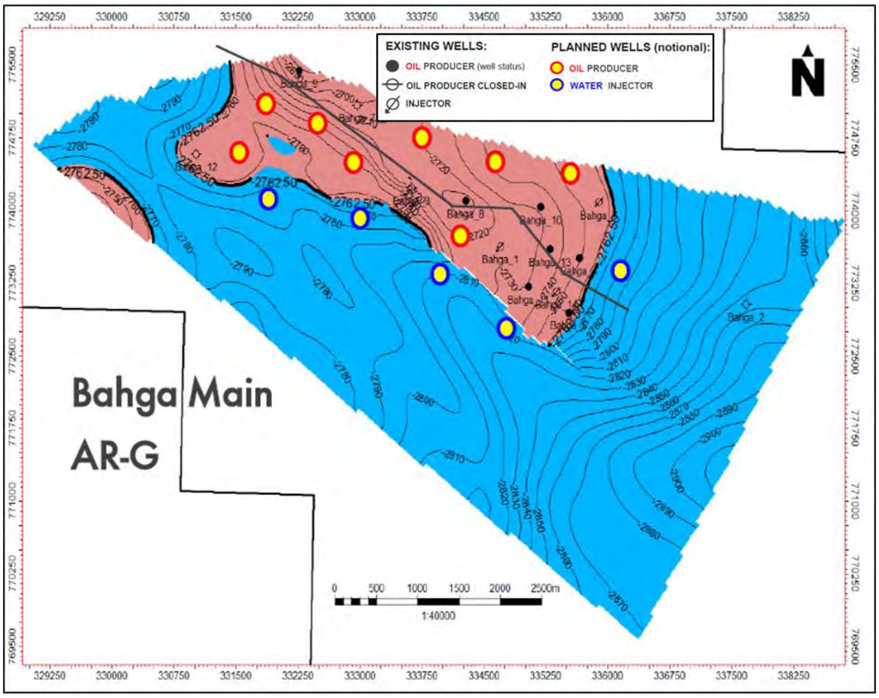
Source: Vendor VDR

Hydrocarbons at Al Magd and Bahga are primarily oil and a relatively small amount of oil production has taken place. A combined 10 MMBbl has been produced up until January 2019 and recovery factors generally remain low compared to the in-place volumes. The vast majority of this production has taken place from the Bahga Field. Near term, future plans consist of water floods for the oil reservoirs and production of gas from the deeper gas targets at Bahga.

2.6.1.1 Structure and Trap

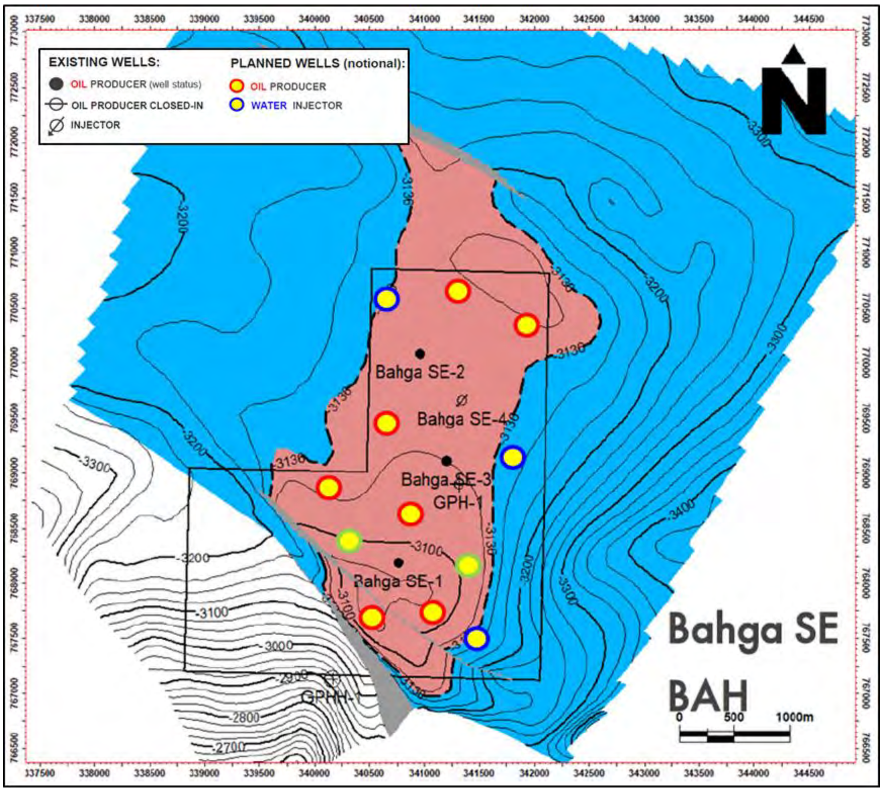
The trapping mechanism at Al Magd, Al Bahga and Al Barq and their satellites is 3-way dip structures, closed against a bounding fault, which is typical for fields in this trend. The Bahga Fields consist of the Main Field and three satellite fields (Bahga C98, Bahga C101 and Bahga SE), these are shown in Figure 63 to Figure 66. The Al Magd Main Field and Al Magd C86 Satellite Fields are shown in Figure 67. The Al Barq Field is presented in Figure 68.

Figure 63: Bahga Main Field Location Map – Abu Roash-G Reservoir Level



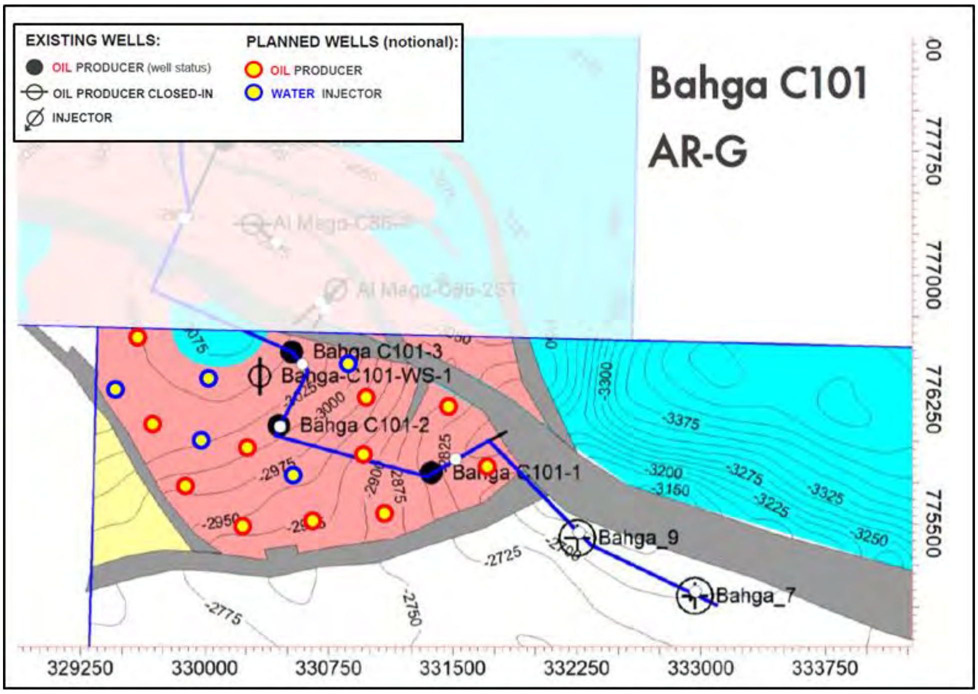
Source: Vendor VDR

Figure 64: Bahga SE Field Location Map – Bahariya Reservoir Level



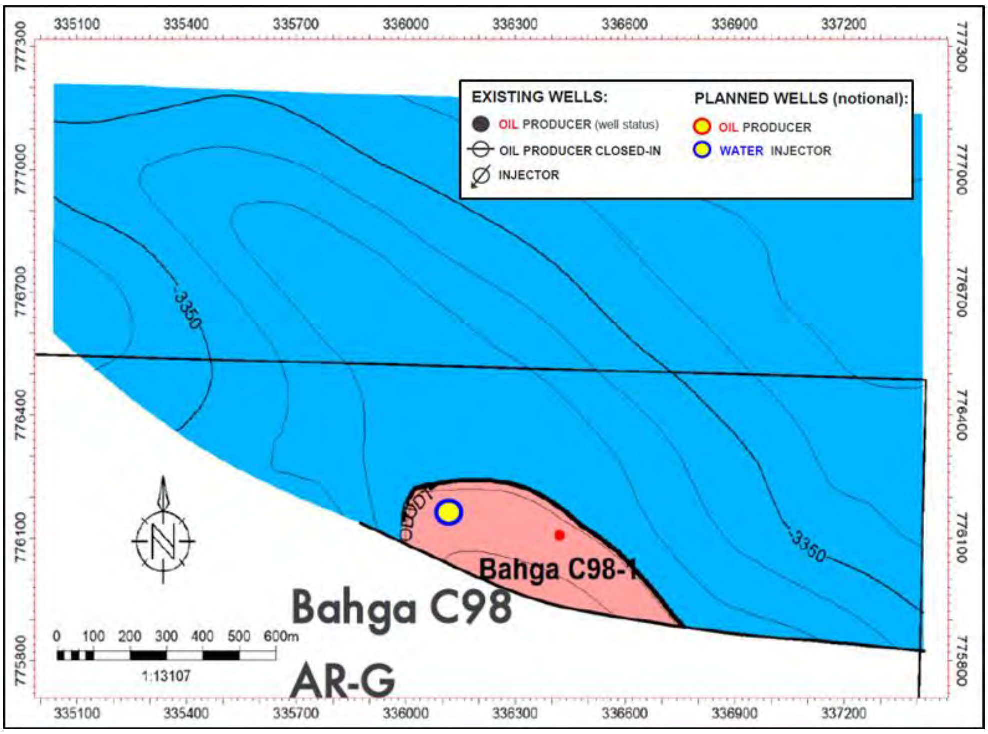
Source: Vendor VDR

Figure 65: Bahga C101 Field Location Map – Abu Roash-G Reservoir Level



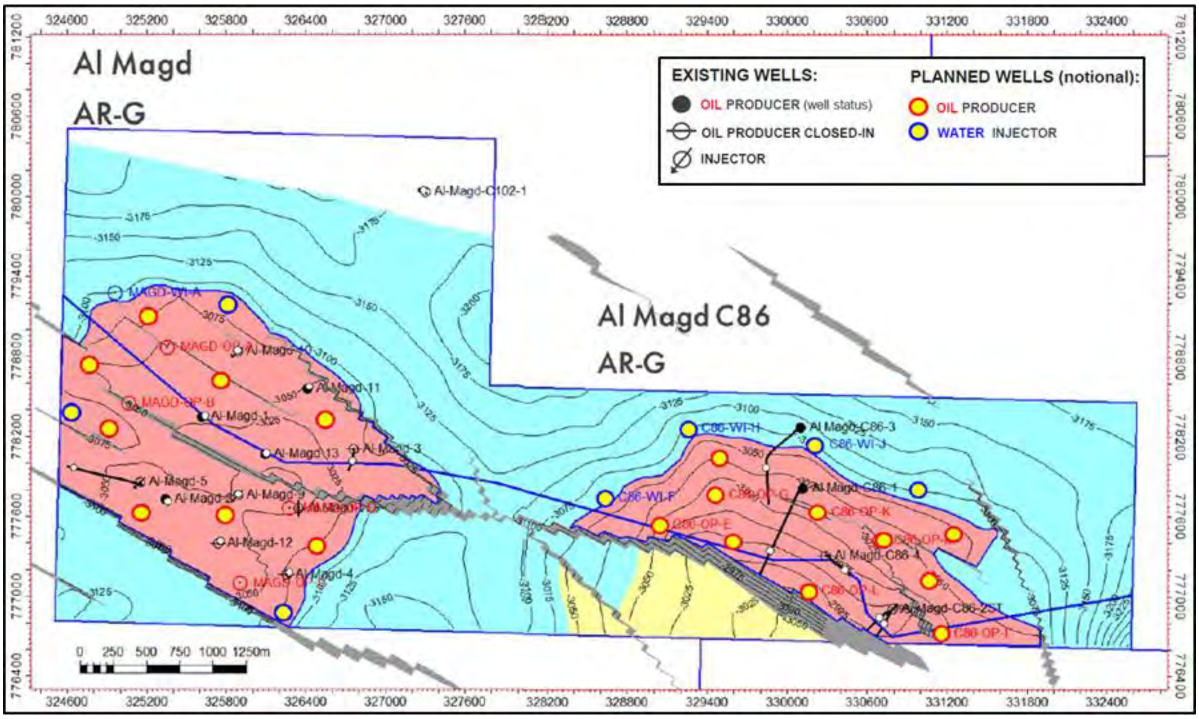
Source: Vendor VDR

Figure 66: Bahga C98 Field Location Map – Abu Roash-G Reservoir Level



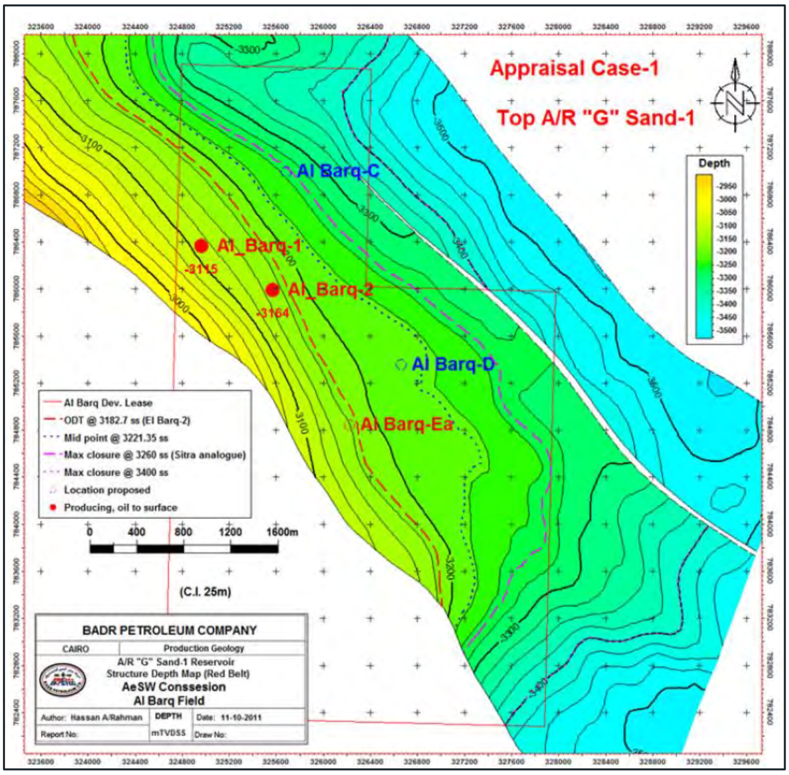
Source: Vendor VDR

Figure 67: Al Magd and Al Magd C86 Fields – Abu Roash-G Reservoir Level



Source: Vendor VDR

Figure 68: Al Barq Field – Abu Roash-G Reservoir Level



Source: Vendor VDR

2.6.1.2 Reservoir

The primary reservoir, in all the fields, is either the Abu Roash G or Bahariya. Top reservoir depths are typically 2,500 m to 3,500 mTVDss. Secondary reservoirs are the Bahariya and Kharita levels.

2.6.1.3 Reservoir and Fluid Properties

Representative PVT data are presented in Table 71. Data from Assil in the Kharita Formation show CO_2 contents of 5.6 mol%. In general pressures and temperatures suggest normal gradients, but there is evidence of moderate overpressuring in Abu Roash Formation reservoirs at Assil and Al Karam.

Table 71: AESW Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Assil-1	KHA	4,125	143.3	6,258	4,553	Not known	67	0.04	0.62
Karam-6	KHA	4,825	158.9	7,560	3,415	Not known	10	0.03	0.69
Karam-3	ARG	4,400	148.9	10,000	6,643	Not known	97	0.06	0.72

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
Assil-2	ARC	3,300	118.9	6,500	4,995	2.90	3500	0.14	47
Assil-2	ARG	3,650	124.2	6,500	1,795	1.33	550	0.50	37
Karam-1	ARG	4,425	147.8	10,280	4,401	2.78	3915	0.07	47
Al Magd-1	ARG	3,000	113.9	4,490	736	1.18	211	0.95	33
Bahga C101-1	KHA	3,175	115.6	4,027	2,071	1.51	813	0.44	40
Bahga-4	ARG	2,900	113.9	4,150	618	1.17	187	1.14	33
Al Barq-1	ARE	No data	112.8	4,485	2,075	1.31	549	0.46	39
Al Barq-1	ARG	No data	115.6	4,760	360	1.09	83.6	2.18	32

2.6.1.4 Production Facilities

At AESW, there are two small remote gathering facilities. These are located in the Al Barq and Bagha areas. The facilities separate the production fluids from their respective areas. The Bagha facility designed to process 6 Mbpd of condensate, and the Al Barq facility is designed to process 3 Mbpd of condensate. Condensate is stored and exported via pipeline to the BED 3 processing plant; gas is used for local power generation and flared if in excess. Produced water is sent for reinjection for disposal, and any excess is routed to evaporation ponds.

2.6.2 HIIP

Where sufficient information was provided in the VDR and or the vPDR, GaffneyCline carried out an independent assessment of the hydrocarbons initially in-place (HIIP) for the volumetrically significant reservoirs using a probabilistic approach.

Logs, core and other data from AESW wells were provided within the VDR. They have been reviewed and a petrophysical interpretation has been performed to provide suitable parameters (e.g. porosity, water saturation, net-to-gross) for the reservoirs of interest, that have been incorporated in the volumetric assessment performed by GaffneyCline. The Assil-4 well was selected to perform a spot-check of the Vendor's petrophysical analysis. Petrophysical parameters were further spot checked by analysis of well logs and or zone averages in any Petrel models that were available.

Gross rock volume (GRV) values presented in the VDR were checked by running any Petrel models or generating estimates of map based GRV using the volumetric tool in Petrel and any associated structural surfaces. Structural surfaces were also checked to see if they honoured well control.

Table 72 and Table 73 present comparisons of the Operator's HIIP estimates, the Vendor's estimates and GaffneyCline's independent estimates. GaffneyCline did not derive independent estimates for minor reservoirs or where data in the VDR and vPDR were not sufficient.

Relatively large differences are observed in the different volumetric estimations at Assil ARG and BAH reservoirs, between the Operator and the Vendor. This is largely due to differences in the depth map used, where different depth maps were tied to different sets of wells. GaffneyCline has taken a range of uncertainty into account in its analysis.

Larger estimates for the Vendor and GaffneyCline at the Al Karam Field are due to recent drilling encountering deeper contacts and more optimistic fault positions that post-date the Operator's estimate.

No geological model was provided for the C101 area and so GaffneyCline made a structural model in order to quality check the GRV and subsequently reduced the GRV in its independent estimate. This ultimately resulted in a reduction to HIIP of approximately 20%.

Table 72: Comparison of HIIP Estimates – Assil and Al Karam

a) Oil (MMBbl)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Assil [ARC]	1.3	N/A	N/A	N/A	N/A
AESW Assil [ARE]	7	N/A	N/A	N/A	N/A
AESW Assil [ARG]	32	62	22	48	93
AESW Assil [BAH]	71	40	21	41	70
AESW Assil C83 [ARE/G]	11	N/A	N/A	N/A	N/A
AESW Karam [ARC]	10	N/A	N/A	N/A	N/A
AESW Karam [ARE]	5	N/A	N/A	N/A	N/A

b) Gas (Bcf)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Assil [KHA] (Bcf)	335	369	213	350	535
AESW Karam [ARG] (Bcf)	143	N/A	N/A	N/A	N/A
AESW Karam [BAH] (Bcf)	182	N/A	N/A	N/A	N/A
AESW Karam [KHA] (Bcf)	1,230	1,797	1,146	1,726	2,480

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Table 73: Comparison of HIIP Estimates – Al Magd, Bahga and Al Barq

a) Oil (MMBbl)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Al Magd [ARG]	14	17.8	12	17	24
AESW Al Magd C86 [ARG]	13	10.2	7	10	14
AESW Bahga [ARG]	34	38	25	36	50
AESW Bahga [BAH&KHA]	11	N/A	N/A	N/A	N/A
AESW Bahga SE [ARG&BAH]	13	12.2	8	12	16
AESW Bahga C98 [ARG]	2	5.4	4	5	7
AESW Bahga C101 [ARG*KHA]	15	14.9	8	12	17
AESW Al Barq [ARE]	3	N/A	N/A	N/A	N/A
AESW Al Barq [ARG]	2	N/A	N/A	N/A	N/A
AESW Al Barq [BAH]	3	N/A	N/A	N/A	N/A

b) Gas (Bcf)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Bahga C98 [BAH&KHA] (Bcf)	18	N/A	N/A	N/A	N/A
AESW Al Barq [ARG] (Bcf)	2	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

2.6.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 74.

Table 74: AESW: Resource Categories in Databook

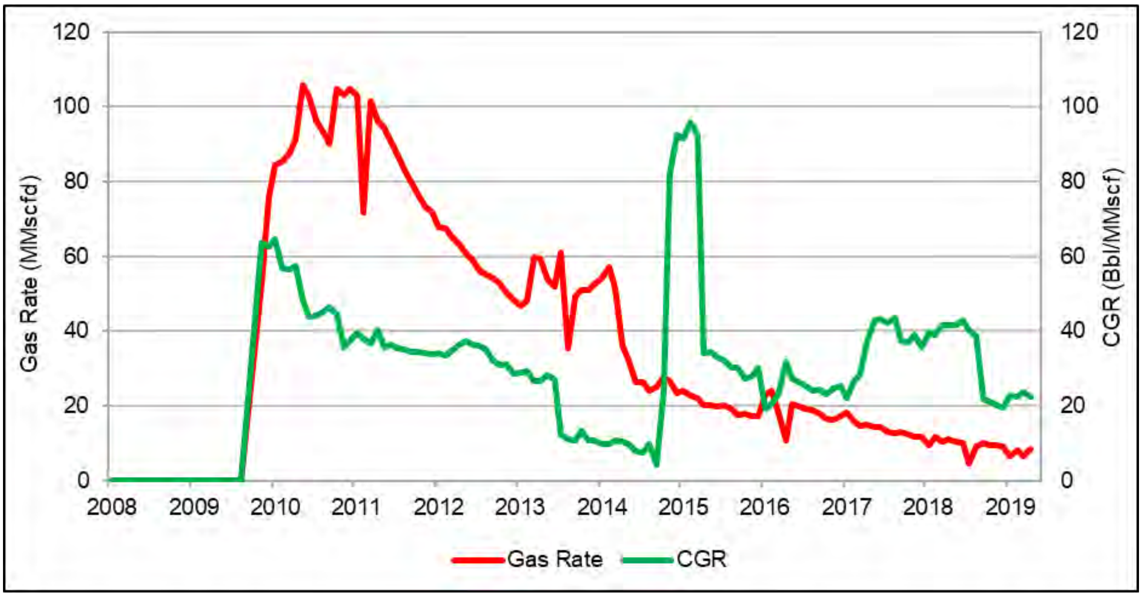
Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
Bahga NFA	Bahga NFA		Reserves
Al Barq NFA	Al Barq NFA		Reserves
Assil NFA	Assil NFA		Reserves
Al Magd NFA	Al Magd NFA		Reserves
Al Karam NFA	Al Karam NFA		Reserves
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
Al Karam infill	Al Karam infill (gas)		Reserves and Contingent Resources
	Al Karam upside (oil)		Contingent Resources
Assil infill	Assil infill (gas)		Reserves
	Assil upside (oil)		Contingent Resources
Al Magd infill	Al Magd infill		Reserves
Bahga infill	Bahga infill		Reserves
General infill	Not included	All development activity viewed as covered by other categories.	N/A
Not included	Shut in wells reactivation	Additional activity developed with client	Reserves
Assil C2E	Near Field Exploration		Prospective Resources
Bahga C2E			
Al Barq C2E			

2.6.4 Historical Field Performance

2.6.4.1 Assil

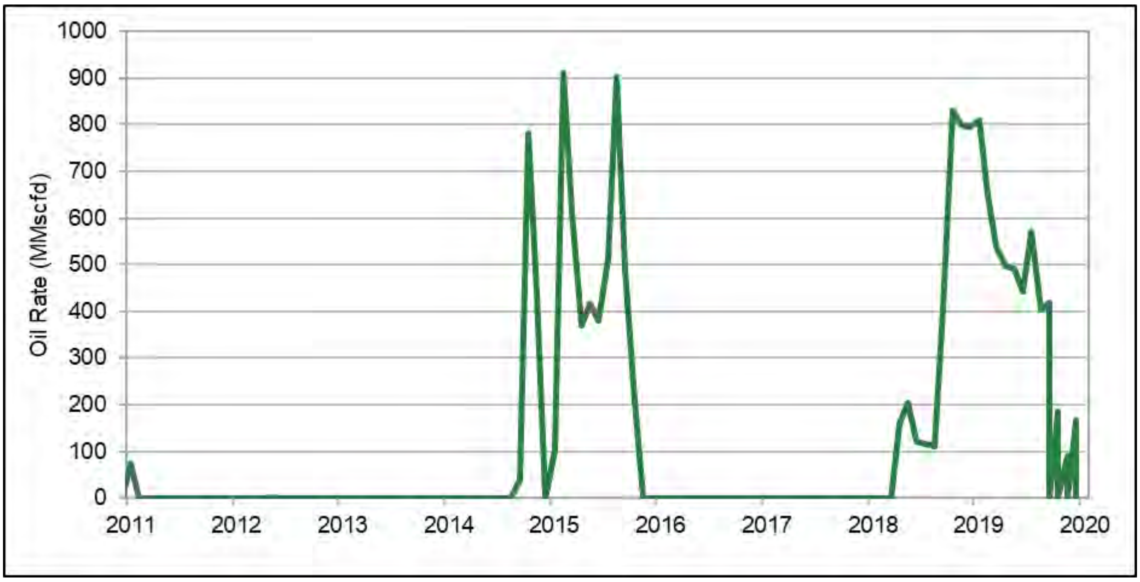
Assil field was discovered in 2007 and production started in July 2010. The development of the Kharita reservoir started with Assil-1, Assil-5 and Assil-6. Peak production was reached in 2011 with a gas production of 106 MMscfd after Assil-7 came on production, see Figure 69. The average gas production and CGR are 8 MMscfd and 21.9 Bbl/MMscf respectively over the last 6 months of production. The gas production is mainly from the Kharita formation.

Figure 69: Historical Gas Production Rate and CGR, Assil (Kharita)



The oil production is mainly from the C83 field from well C83-1 ARG and Assil -03 ARC and Assil-08 wells. The average oil production over the last six months is 160 bpd (Figure 70).

Figure 70: Historical Oil Production Rate, Assil

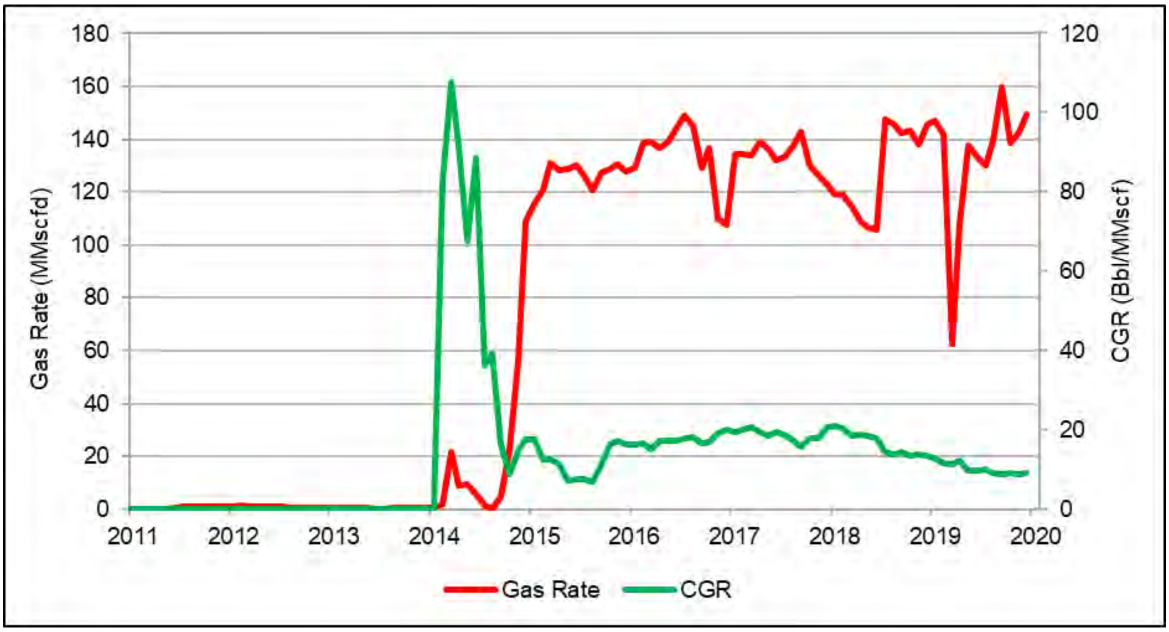


2.6.4.2 Al Karam

The development of the Kharita reservoir stated in 2014 with three wells. In 2016 a fourth well was drilled and a final well drilled in 2018. The plateau gas rate has been maintained at 120-150 MMscfd since start of production.

Figure 71 and Figure 72 show the gas and oil production history respectively from the Al Karam field.

Figure 71: Historical Gas Production Rate and CGR, Al Karam



The oil production commenced in 2008 reaching a peak production of 471 bopd and has since ceased. Oil production mainly from Karam-02ST in the ARG formation.

Figure 72: Historical Oil Production Rates, Al Karam

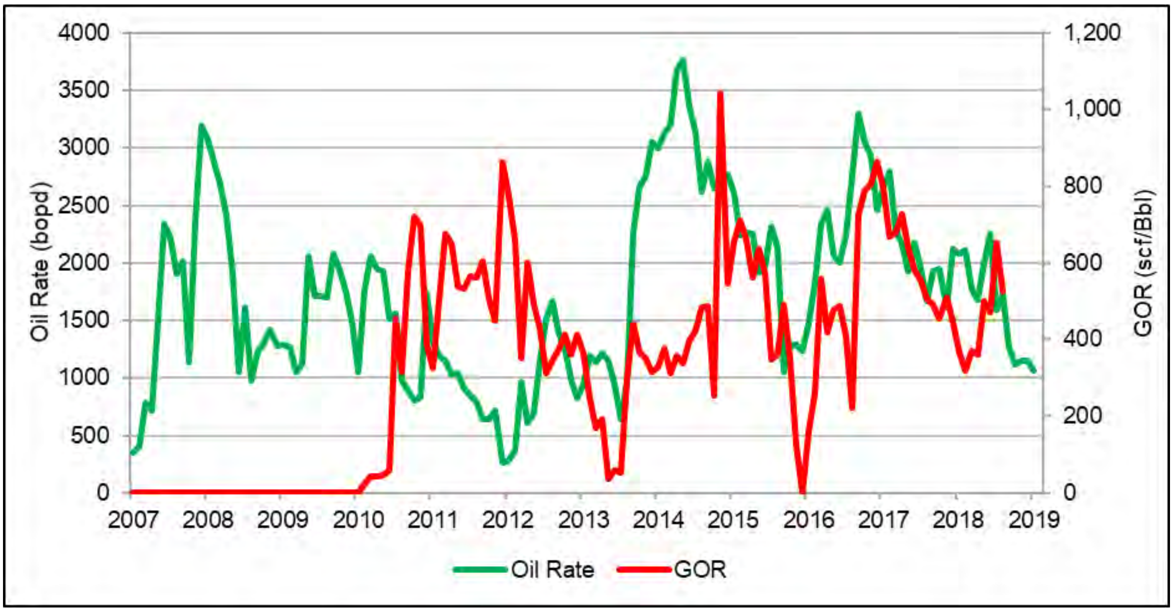
2.6.4.3 Bahga

Bahga includes four sub reservoirs: Bahga Main, Bahga Southeast (SE), Bahga C101 and Bahga C98. Bahga Main production started in December 2007 with the Bahga-01 well. Water injection pilots started in 2012 and a water flood scheme was implemented 2014. Bahga South East (SE) began in 2010 through Bahga SE-1, with additional wells adding to production Bahga SE-2 in 2017 and Bahga SE-3 in 2019.

Bahga C101 was producing from three wells (C101-1, C101-2 and C101-3), currently producing from one well C101-1.

Figure 73 shows the total production history for Bahga, which includes, Bahga Main, Bahga SE and Bahga C101.

Figure 73: Historical Oil Production Rates, Bahga (Main, SE and C101)

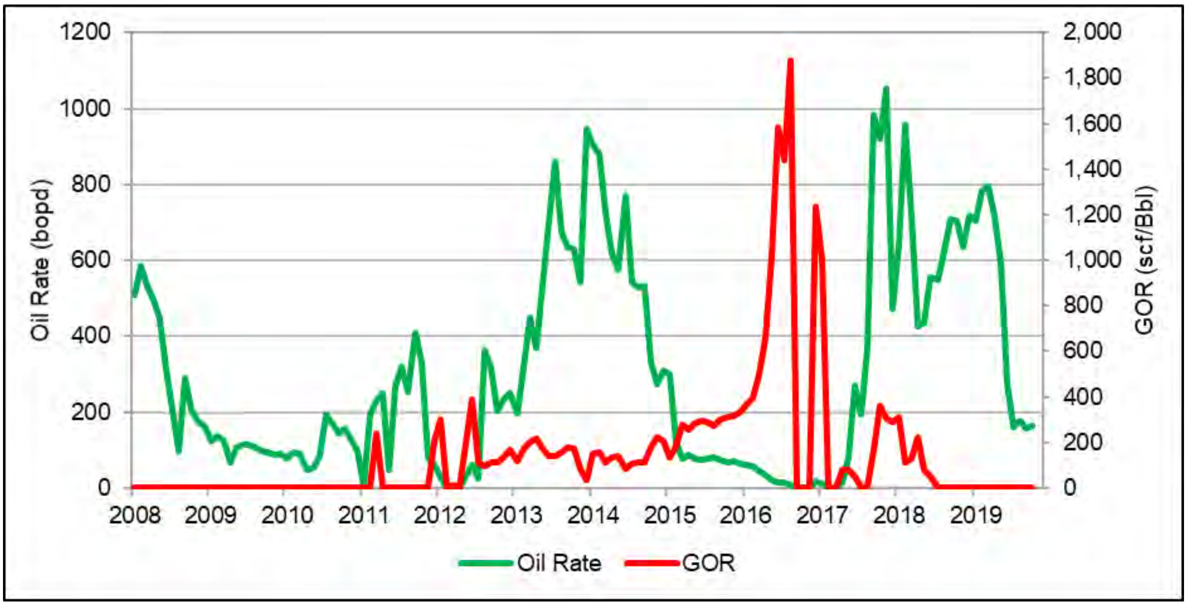


2.6.4.4 *Al Magd*

Al Magd include two sub reservoirs, Al Magd Main and Al Magd C83.

Al Magd Main began production in early 2008, waterflood commenced in 2014 with the conversion of Al Magd-3 producer to an injector. Al Magd C83 started production in 2012. Figure 74 shows the Al Magd production history.

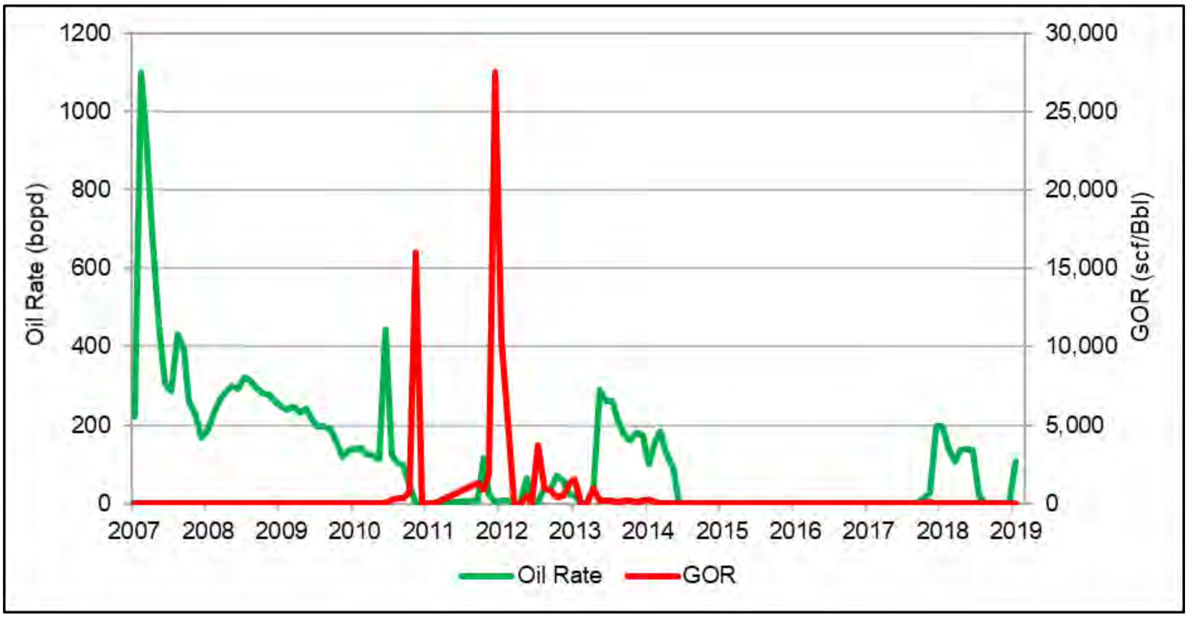
Figure 74: Historical Oil Production Rates and GOR, Al Magd



2.6.4.5 Al Barq

Al Barq production commenced in 2007 with a peak production of 1,100 bpd with two wells (Barq-01 and Barq-02 in the ARG and ARC reservoirs, it since has declined very sharply. Three more wells were drilled in 2012 (Barq-03, 04 and 05) with similar performance to the original two wells. Figure 75 shows the Al Barq production history.

Figure 75: Historical Oil Production Rates and GOR, Al Barq



2.6.4.6 Summary

Total cumulative oil and water production for AESW, along with recent rates are shown in Table 75.

Table 75: AESW Fields Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
Al Assil	5	0.5	146.6	215.7	7.5	92.5
Al Karam	6	0.5	247.2	0.0	147.7	816.0
Bahga	10	7.7	2.7	1,122.1	0.8	356.3
Al Magd	5	1.3	0.1	164.1	0.0	32.5
Al Barq	1	0.5	0.0	26.6	0.0	0.0
Total	**27**	**10.4**	**396.7**	**1,528.5**	**156.0**	**1,297.3**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.6.5 Field Development Plan

Where available in the VDR, proposed drilling locations for the Fields in AESW are shown in Figure 61 to Figure 68.

2.6.5.1 Assil

The Consortium’s future development plans for the Assil field include two infill wells in the Kharita gas reservoir in Assil Main and one well in C83 area targeting the ARG oil reservoir.

The first of the Assil Main wells has been drilled after the Effective Date of this Report in 1Q 2020 as Assil-9. This is located on the southern crestal area of the field and successfully produces gas from the Kharita Formation. A later well will target the northern fault block of the field.

Also during 1Q 2020, well Assil C83-2, has been drilled and brought on stream as an Abu Roash G oil producer.

The drilling schedules for the Kharita and ARG reservoirs are summarized in Table 76 and Table 77.

Table 76: Assil, Kharita Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	0	0	1	0	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**1**	**0**	**0**	**1**	**0**	**2**

Table 77: Assil, ARG Oil Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	0	0	0	0	**1**
Injection Wells	0	0	0	0	0	**0**
Total	**1**	**0**	**0**	**0**	**0**	**1**

2.6.5.2 Al Karam

The Consortium’s future development plans for Al Karam include eight new infill wells in the Kharita gas reservoir and six new infill wells in the ARG/BAH gas reservoir. The drilling schedules are summarized in Table 78 and Table 79.

Table 78: Al Karam, Kharita Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	4	3	1	0	**8**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**4**	**3**	**1**	**0**	**8**

Table 79: Al Karam, ARG/BAH Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	3	3	0	**6**
Injection Wells	**0**	0	0	0	0	**0**
Total	**0**	**0**	**3**	**3**	**0**	**6**

2.6.5.3 Bahga

The Consortium’s future development plans for Bahga include six infill producer wells and three injectors in Bahga Main, seven infill producers and one injectors in Bahga SE, and eleven infill producers and three injectors in Bahga C101. No new infill wells planned for C98. The drilling schedules are summarized in Table 80, Table 81 and Table 82 respectively.

Table 80: Bahga (Main), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	1	5	0	0	**6**
Injection Wells	**0**	0	3	0	0	**3**
Total	**0**	**1**	**8**	**0**	**0**	**9**

Table 81: Bahga (SE), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	2	3	2	0	**7**
Injection Wells	0	0	1	0	0	**1**
Total	**0**	**2**	**4**	**2**	**0**	**8**

Table 82: Bahga (C101), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	1	1	0	7	**11**
Injection Wells	0	0	0	0	3	**3**
Total	**2**	**1**	**1**	**0**	**10**	**14**

2.6.5.4 Al Magd

The Consortium's future development plans for the fields include the following activities:

- Seven Infill producer wells and two injectors planned in Al Magd Main;
- Seven infill producers and two injectors planned in Al Magd C86.

The schedule and number of new production wells for Al Magd Main and Al Magd C86 reservoirs are summarized in Table 83 and Table 84 respectively.

Table 83: Al Magd (Main), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	7	0	**7**
Injection Wells	0	0	0	2	0	**2**
Total	**0**	**0**	**0**	**9**	**0**	**9**

Table 84: Al Magd (C86), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	4	0	0	3	0	**7**
Injection Wells	0	0	0	2	0	**2**
Total	**4**	**0**	**0**	**5**	**0**	**9**

2.6.5.5 Al Barq

No further development is planned for Al Barq oil reservoir.

2.6.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (April 2033). Al Bagha PSA expiry is 28th May 2032.

Table 85 and Table 86 shows the remaining technical recoverable volumes for Assil and Al Karam.

Table 85: Remaining Technically Recoverable Gas Volumes, AESW, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
Al Karam	514.1	637.5	796.4
Assil	55.3	69.4	90.3
Bagha	1.0	2.6	5.5
Al Magd	0.0	0.0	0.0
Al Barq	0.0	0.0	0.0
Sl Re-activation	1.4	1.5	1.6
Total	**571.8**	**711.0**	**893.8**

Notes:

1. The volumes in this tables are to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO_2 removal.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 86: Remaining Technically Recoverable Oil and Condensate Volumes, AESW, as at 31st December 2019

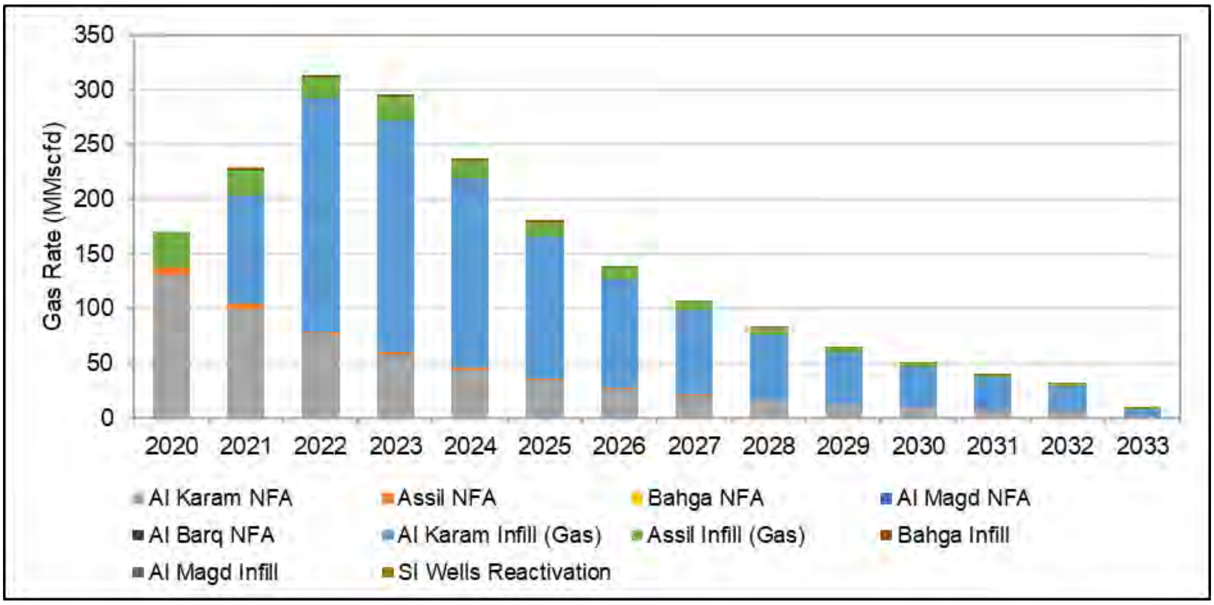
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Al Karam	5.9	9.7	12.6
Assil	3.9	5.2	7.1
Bagha	2.9	7.5	13.4
Al Magd	0.9	3.7	7.5
Al Barq	0.1	0.1	0.1
Sl Re-activation	4.1	4.3	4.5
Total	**17.8**	**30.5**	**45.2**

Notes:

1. The volumes in this tables are to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 76 and Figure 77 shows the best case gas and condensate production forecasts for AESW by activity.

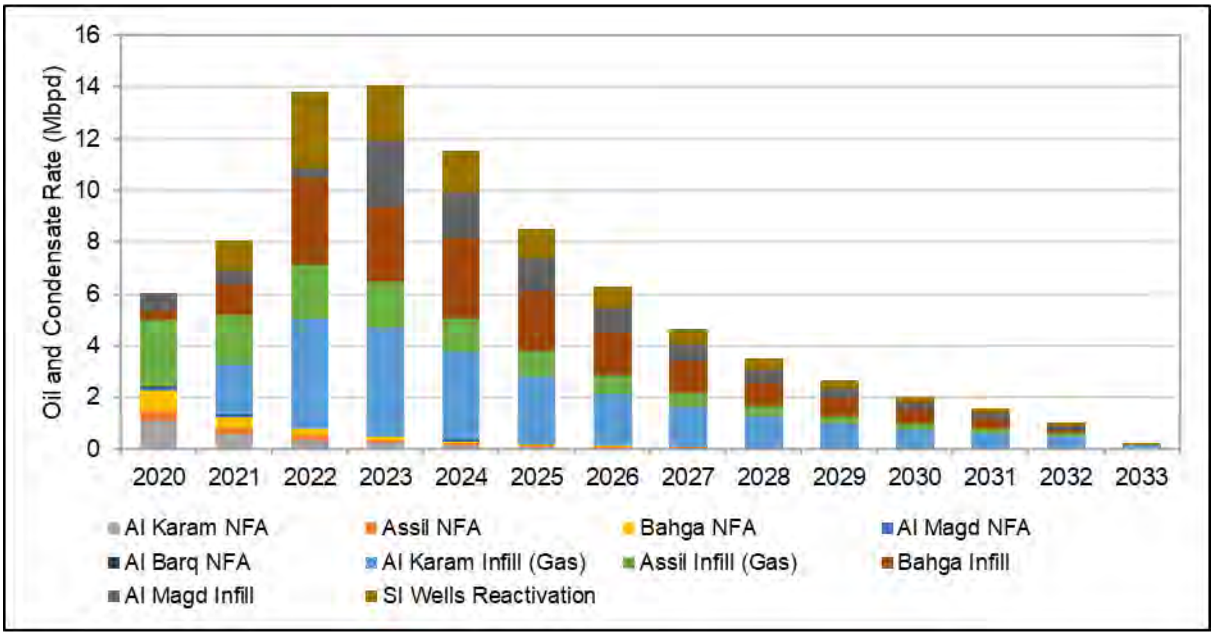
Figure 76: Best Case Gas Production Forecast, AESW



Notes:

1. The values in this figure are annual average rates to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO2 removal.

Figure 77: Best Case Oil and Condensate Production Forecast, AESW

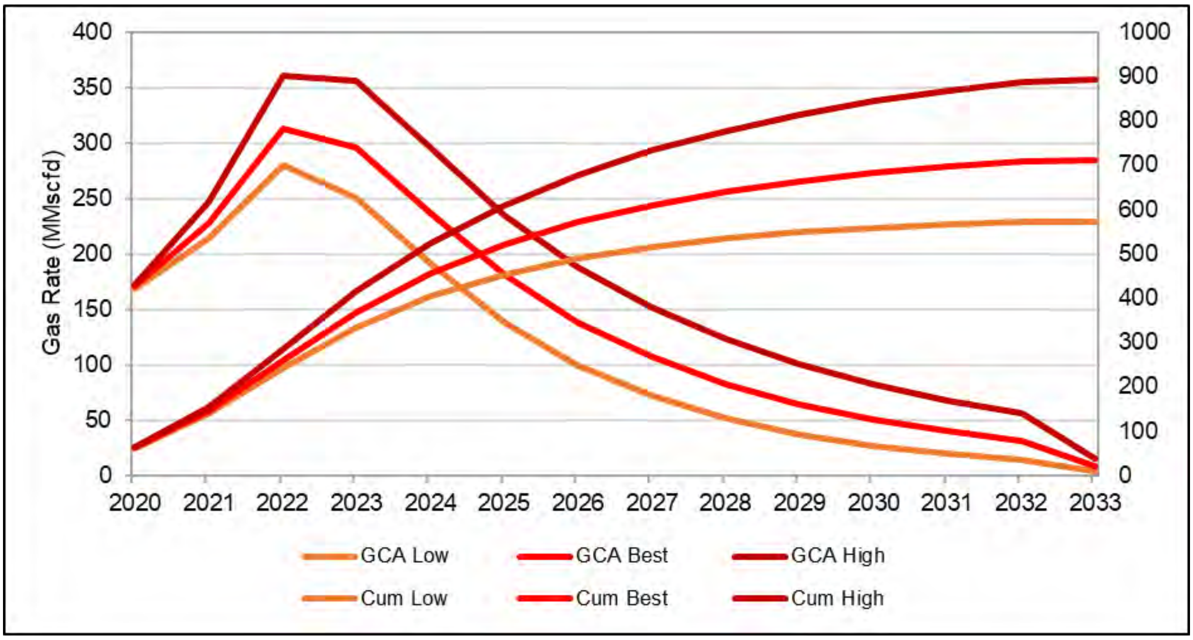


Note:

1. The values in this figure are annual average rates to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.

Figure 78 and Figure 79 show the Low, Best and High production forecasts for AESW.

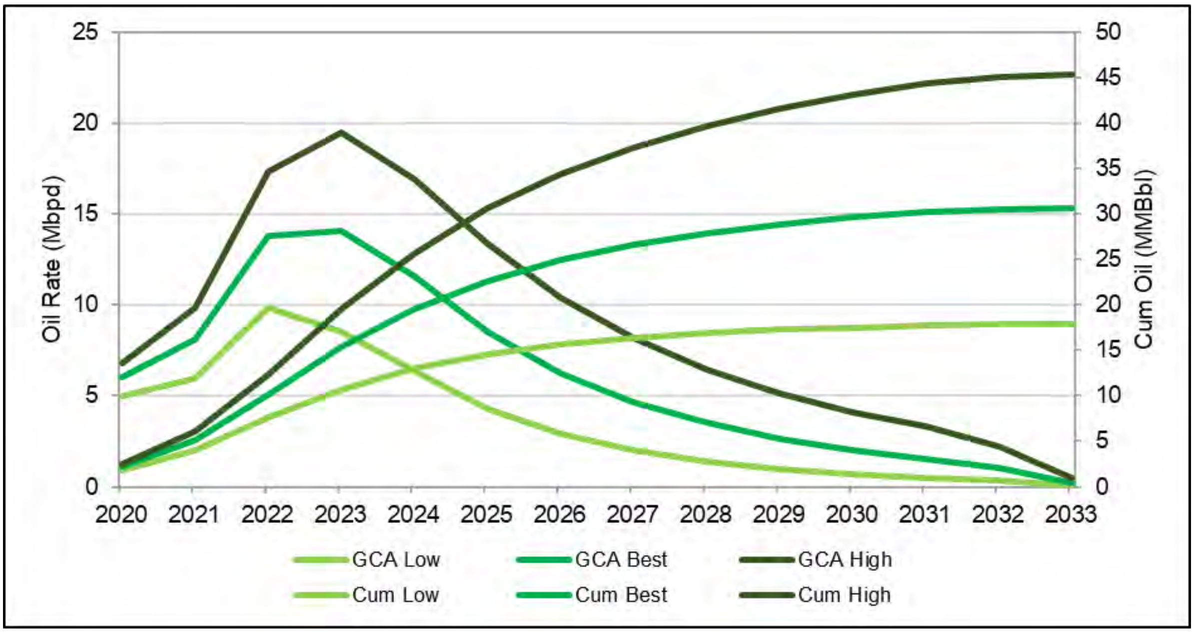
Figure 78: Gas Production Forecasts, AESW



Notes:

1. The volumes in this figure are annual average rates to end of May 2032 for Bahga & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO2 removal.

Figure 79: Oil and Condensate Production Forecasts, AESW



Note:

1. The volumes in this figure are annual average rates to end of May 2032 for Bahga & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.

2.6.7 Contingent Resources

Contingent Resources have been assigned to wells for which locations have not yet been defined. Further modelling work is required to bring to these opportunities to a higher level of confidence. The Contingent Resources are assigned to:

- Incremental oil production from 14 infill wells in Assil (Main), in the ARC and Bahariya formations, as well as 8 new injectors;
- Gas and condensate from two wells in the Al Karam Kharita gas; and
- Oil production form three infill wells in the Al Karam ARC reservoir.

The AESW Contingent Resources are summarized in Table 87.

Table 87: Gross Contingent Resources. AESW, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
A Karam Kharita	76.6	92.4	116.2
Al Karam ARC	0.0	0.0	0.1
Assil	0.1	0.4	1.1
Total	**76.7**	**92.8**	**117.4**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Al Karam Kharita	1.1	1.8	2.3
Al Karam ARC	0.3	1.0	1.9
Assil	0.7	2.1	3.6
Total	**2.1**	**4.9**	**7.8**

Notes:

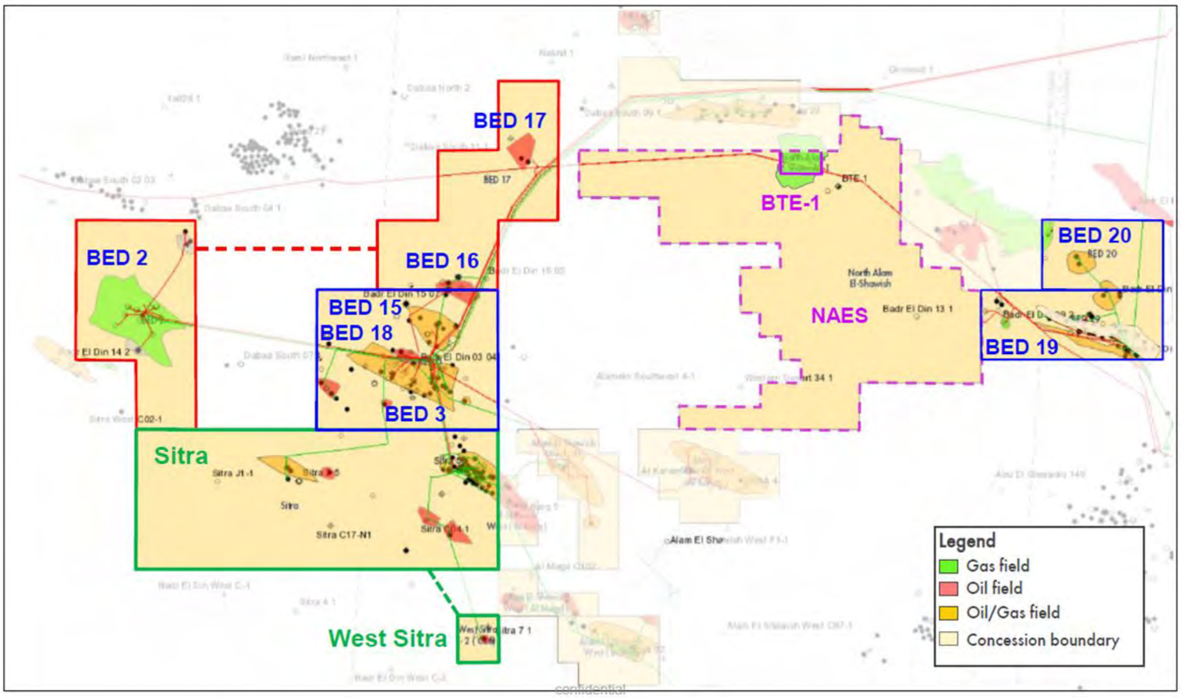
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.7 North Alam El Shawish (NAES)

2.7.1 Asset Description

The NAES concession is located close to the BED and Sitra areas (see Figure 80). The primary component of the concession is the BTE Field. The BTE gas field was discovered in 2016 by the BTE-2 well. Following a production test from the BTE-2 well, the concession was converted into a development lease in 2017. Up to January 2019, some 9.8 Bscf had been produced from the BTE-2 well. Production from this single well is ongoing.

Figure 80: NAES Concession – Location Map



Source: Vendor VDR

There is significant uncertainty associated with the volumetric estimation of the field. The BTE-4 appraisal well was drilled in a down-dip location in 2019/2020 and encountered more than 200 m of net pay and successful production tests were run in several intervals.

2.7.1.1 *Structure and Trap*

The trapping mechanism is a 3-way dip closure, which is ultimately bound to the NE by a large fault. The structure itself is further faulted by several smaller faults. The Field is currently under-appraised as only 2 wells penetrate the reservoir and the field appears to cover a relatively large geographical area, of more than 30 km^2. Figure 81 shows a top reservoir structure map and the location of the two wells. The initial results suggest that the first two wells are potentially not in communication with each other. Due to the nature of the reservoir and structural configuration of the field, it is likely that the ultimate dynamic behaviour of the reservoir will show some compartmentalization.

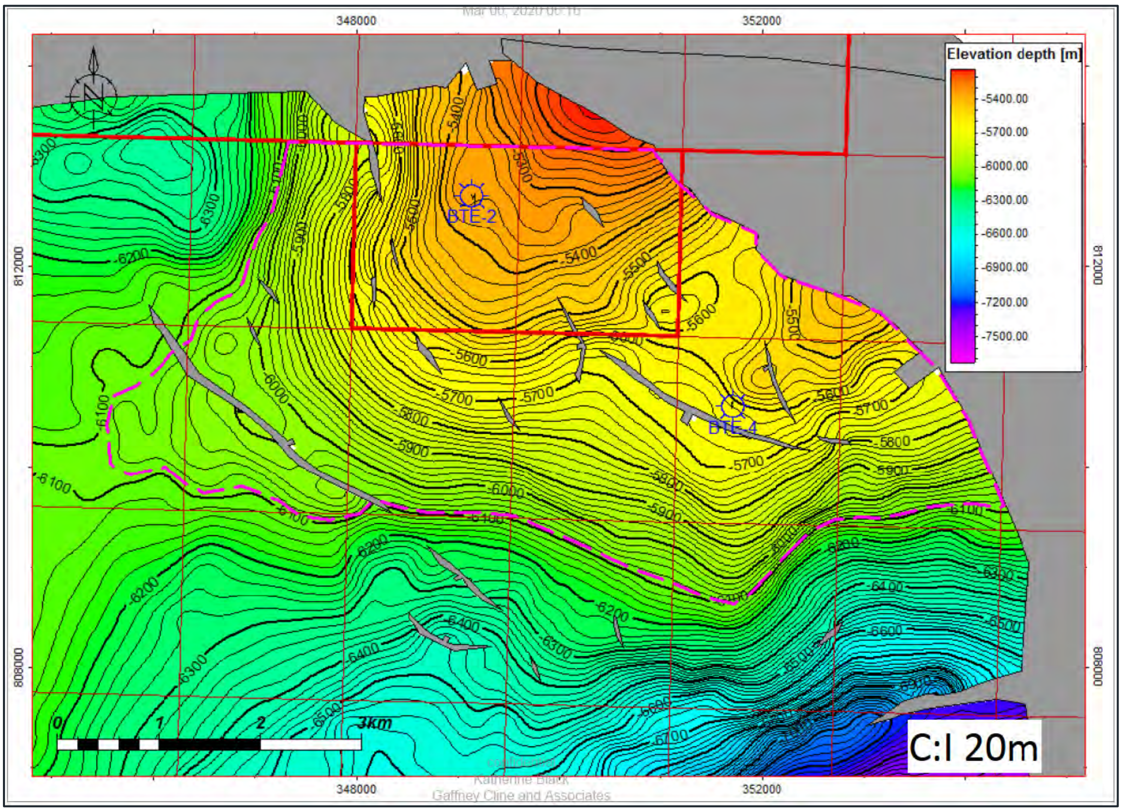
2.7.1.2 *Reservoir*

The primary reservoirs at BTE are the tight Kharita reservoir intervals, which have been found to contain gas. The Kharita reservoirs are Early Cretaceous in age and consist of sandstones deposited in a mixture of shallow marine to terrestrial environments. Secondary reservoirs in the Abu Roash C and E intervals are thought to contain oil based on interpretation of log data. The Kharita gas reservoirs are situated at a depth range of 5,200 to 6,000 mTVDss. The reservoir quality is considered to be tight with porosities typically ranging from 4 to 7% and permeability is approximately 10 mD.

Both the BTE wells drilled to date have been tested with the following results:

- BTE-2:
  - Zone K7 test: Gas: 20 MMscfd, Condensate: 0.5 Bbl/MMscf, Water: 100 bpd.
- BTE-4:
  - Zone K5 test: 27 MMscfd;
  - Zone K7 test: Very low gas rates.

Figure 81: BTE Field – Top Kharita-3 Reservoir Structure Map and Drilled Well Locations



2.7.1.3 *Reservoir and Fluid Properties*

Representative PVT sample data are presented in Table 88. Reported CO_2 content is moderate in the sample data, ranging from 2.1 to 3.4 mol%, but higher values have been reported on test from BTE-4 of up to 8.0 mol%. There is evidence of moderate overpressuring in both Abu Roash and Kharita Formations, and of a slightly lower geothermal gradient than in adjacent fields.

Table 88: NAES Area: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BTE-4	KHA	Not known	Not known	Not known	Not known	Not known	2	Not known	0.78
BTE-4	KHA	5,735	157.7	8,809	Not known	Not known	32	Not known	0.68
BTE-4	ARC	4,560	131.7	9,247	Not known	Not known	85	0.01	0.67
BTE-2	KHA	4,795	143.9	11,972	Not known	Not known	79	0.01	0.80

2.7.1.4 Production Facilities

Gas is evacuated via the BED 19 pipeline to BED 3 gas processing facility (see section 2.3).

2.7.2 HIIP

GaffneyCline carried out some high level petrophysical analysis of the recently drilled BTE-4 well, which, at the time of writing, had not been fully integrated into the technical work of the Operator.

In total, 212 m of Kharita pay were interpreted in 10 sub-layers. All the interpreted reservoir intervals are tight. Using a 3% porosity cut-off the average net pay porosity is approximately 5%. The K5 interval that tested good rates has 58 m of interpreted net pay with 6% average porosity, while the K7 interval that exhibited very low flow rate has 32 m of interpreted net pay with 5% average porosity. The K8 and K9 intervals were tested but did not flow; a total of 49 m of net pay is interpreted, with 4-5% average porosity. The K4 interval was not tested but has an average porosity similar to K5 (16 m of interpreted pay with 6% average porosity) and so might be expected to flow in a similar way to the K5 reservoir.

Different pressure measurements in BTE-4 and BTE-2 within the K5 zone indicates compartmentalization (as is listed as a risk by the vendor).

The Petrel model provided in the vPDR, did not incorporate the findings of the BTE-4 well and the structural surfaces did not tie the well. Therefore, GaffneyCline derived an independent estimate of HIIP. GRV was derived from hand digitised and well-tied structural surfaces.

- A Low Case GRV was taken as the GDT or top of next reservoir unit down;
- A High Case GRV was taken at the spill point of each reservoir level, based on the depth maps generated;
- The Base Case GRV was taken as a combination of the Low and High Cases;
- Reservoir parameters were derived from the petrophysical averages from the BTE-2 and BTE-4 wells;

- Wide parameter ranges were used due to the apparent subsurface variability of the Kharita reservoir and small number of well penetrations in the field, which itself covers a relatively large area.

Based on the limited data available, GaffneyCline included the following intervals in its assessment:

- Low Case reservoirs: K3, K5 and K7;
- Base Case reservoirs : K3, K4, K5 and K7;
- High Case reservoirs: all interpreted net pay intervals (K6 has none).

A Monte Carlo analysis was then performed using a Crystal Ball model for each reservoir level to derive estimates of GIIP. Table 89 presents a comparison of the Operator's, Vendor's and GaffneyCline's results.

Table 89: Comparison of GIIP Estimates (Bscf) – BTE Field

Reservoir Unit	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
			Low	Best	High
NAES BTE Kharita	1,122	697	573	649	953

GaffneyCline's estimate is broadly similar to that of the Vendor. It is thought that the Operator's estimate does not take into account the observations of the BTE-4 well. Oil phase hydrocarbons potentially identified on well logs at shallower intervals have not been quantified here.

2.7.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 90.

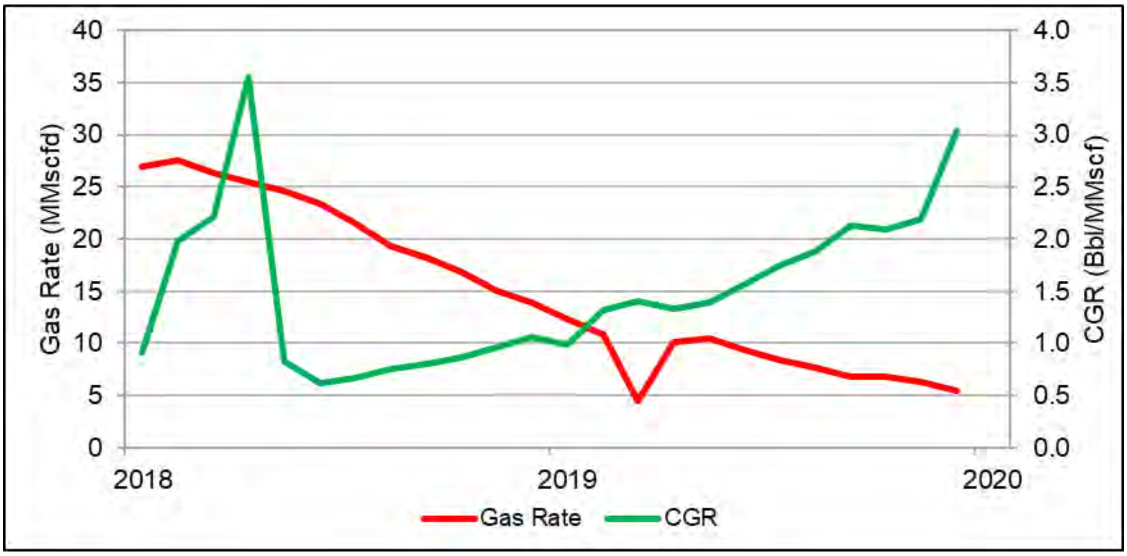
Table 90: AESW: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline Interpretation	Categorisation/Notes
NFA	NFA		Reserves
Exploration	Near Field Exploration	Included under this vendor description, although includes appraisal and development following the BTE-4 well.	Reserves

2.7.4 Historical Field Performance

Production from the BTE-2 well started in November 2018. The initial production rate was 27.5 MMscfd and has subsequently fallen to 5.5 MMscfd (Figure 82). The current CGR is 3 Bbl/MMscf. The cumulative gas production to the end of 2019 is 10.9 Bscf.

Figure 82: Historical Gas Production Rate and CGR, BTE-2 (NAES)



2.7.5 Field Development Plan

Reserves are attributed to 2 additional wells which are in the Consortium's 5 year business plan. The last technical study presented by the Operator is dated 2017, prior to the drilling of the BTE-4 well, and outlined a notional 8-well development plan, but gave no locations for these wells. Further work is needed to define a more complete development plan, with the next few development wells acting to appraise the field.

Table 91: BTE Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	0	2	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**0**	**0**	**2**	**2**

2.7.6 Production Forecasts

GaffneyCline produced production forecasts for the existing BTE-2 well and the future infill wells for the period from 2020 to the expiry of the PSA (September 2042). Based on the performance of BTE-2 well, an EUR of 13 Bcf/well is assumed. Table 92 shows the remaining technical recoverable volumes for Assil and Al Karam.

Table 92 shows the remaining technical recoverable volumes for BTE.

Table 92: Remaining Technically Recoverable Gas Volumes by Case, BTE, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
NFA	1.9	2.8	3.8
Infill	14.0	25.8	40.9
Total	**15.9**	**28.6**	**44.7**

Notes:

1. The values in this table are to the end of September 2042; no economic cut off has been applied.
2. The volumes are prior to deduction of fuel and shrinkage, estimated at 12% in 2020-2023 and 12.5% from 2023 onwards (Fuel = 4.5% and shrinkage due to CO_2 removal= 7.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 83 shows the Best Case gas production forecast for BTE by activity.

Figure 83: Best Case Gas Production Forecast, BTE

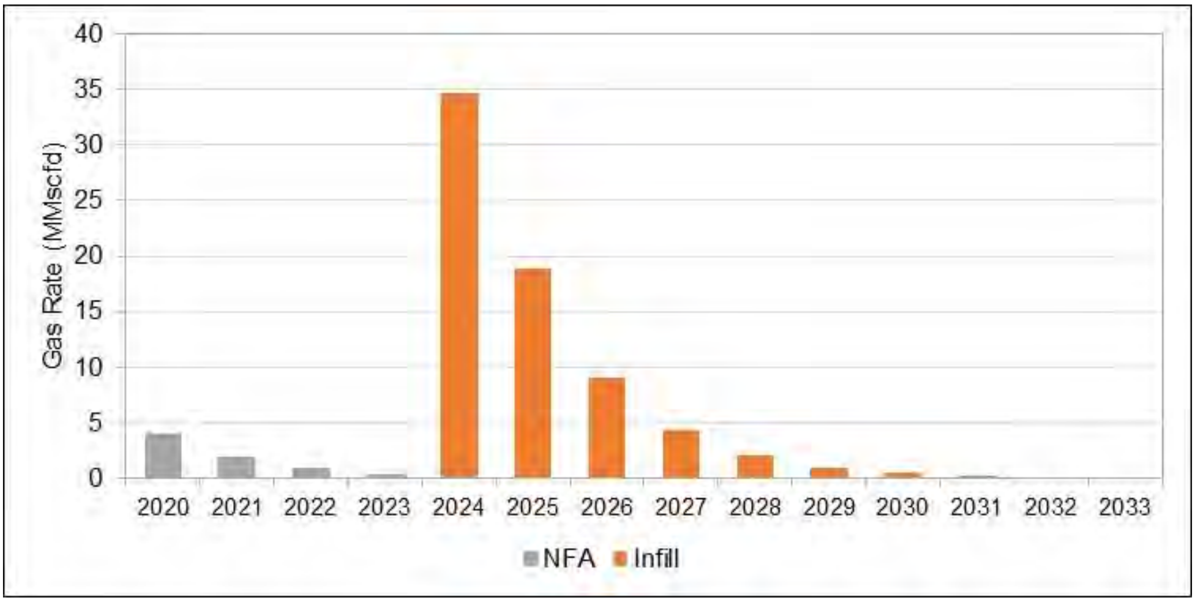
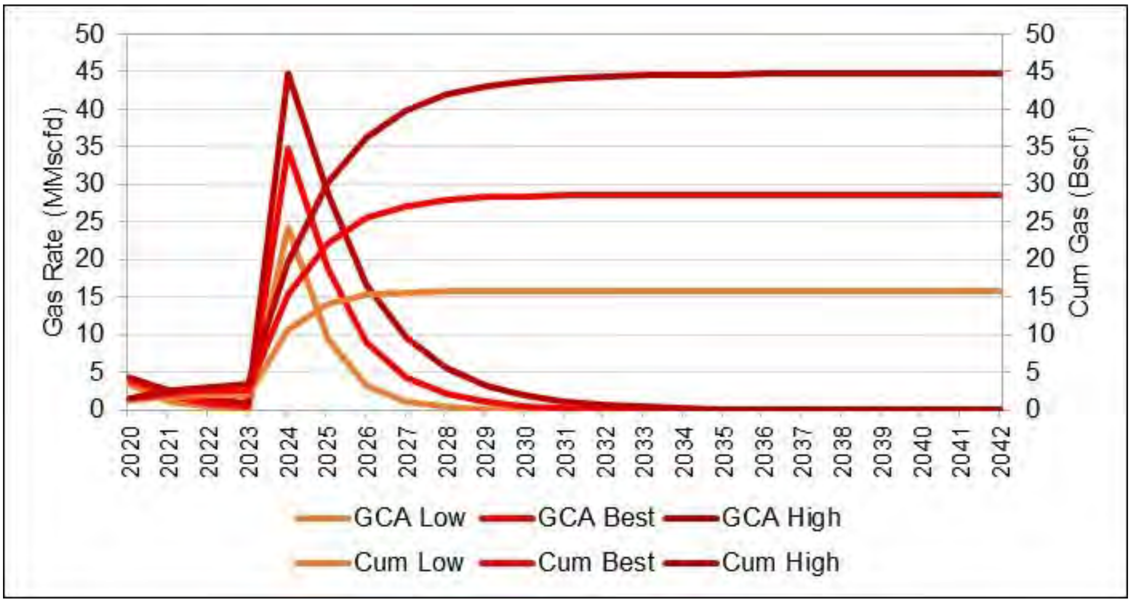


Figure 84 shows the Low, Best and High gas production forecasts for BTE.

Figure 84: Gas Production Forecasts, BTE



Notes:

1. The values in this table are to 17th of September 2042; no economic cut off has been applied.
2. The values are prior to deduction of fuel and shrinkage, estimated at 12% in 2020-2023 and 12.5% from 2023 onwards (Fuel = 4.5% and shrinkage due to CO_2 removal= 7.5%).

2.7.7 Contingent Resources

The full potential of the BTE field is as yet unclear but based on the estimates of GIIP and assuming reasonable overall recovery factors suggests a full field development might require in the order of 20 wells (Table 93).

Table 93: GIIP, EUR and RF, BTE, as at 31st December 2019

Case	Low	Best	High
GIIP (Bcf)	573	649	953
EUR (Bcf)	171.9	259.6	476.5
RF (%)	30	40	50

Contingent Resources have been assigned to 17 infill wells in the BTE area, where modelling and well locations have not yet been fully matured (Table 94).

Table 94: Gross Contingent Resources, BTE, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Gas	118.6	219.1	347.9

(b) Condensate

	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Condensate	0.1	0.2	0.5

Notes:

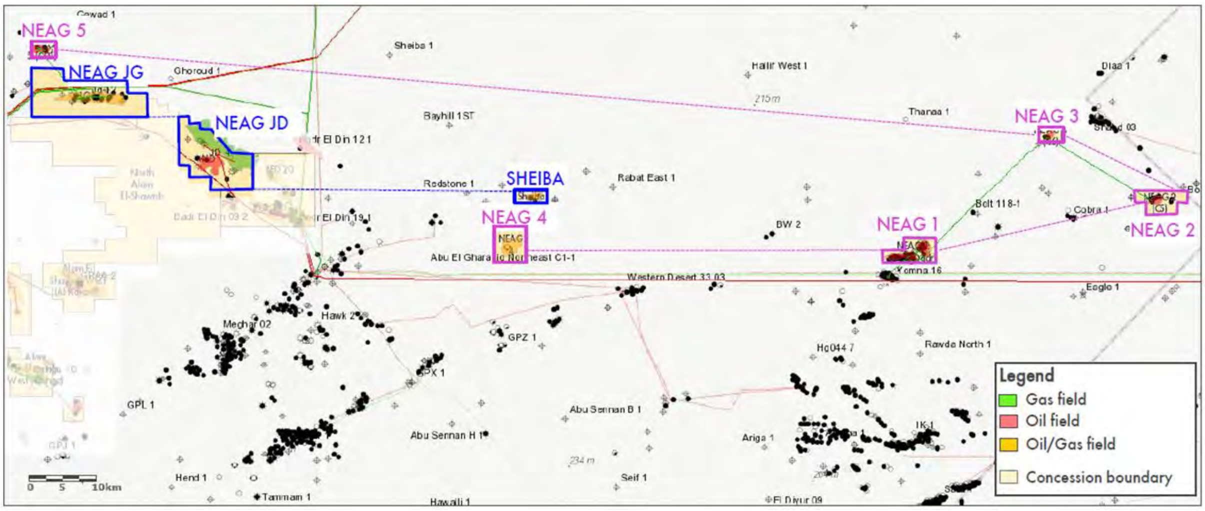
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.8 North East Abu Gharadig Extension and Tiba (NEAG Ext and NEAG Tiba)

2.8.1 Asset Description

The NEAG group of assets is comprised of several concessions and fields distributed over a large geographical area of some 5,000 km^2. There are two main components to the NEAG area. The NEAG Ext consists of five fields (NAEG 1 to 5) which are distributed primarily in the east of the area, with one field in the west and NEAG Tiba, which consists of three fields, in the west of the area. Figure 85 presents a map of the entire NEAG area and the various components. The NEAG Ext is shown in pink and NEAG Tiba is shown in blue in Figure 85.

Figure 85: NEAG Ext and NEAG Tiba – Location Map



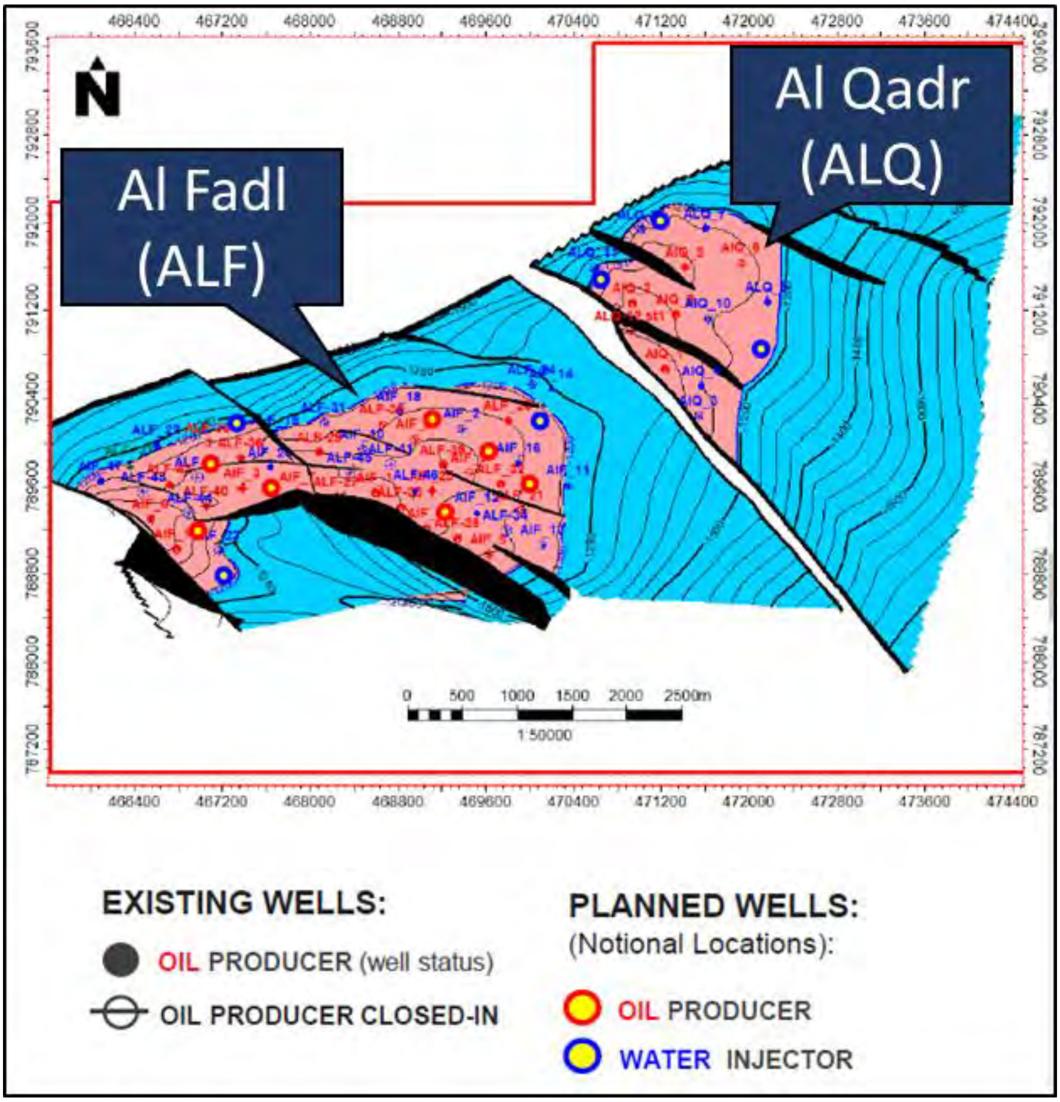
Source: Vendor VDR

In the NEAG Ext area the focus to date has been the production of oil from the Bahariya reservoirs in NEAG 1 & 2, where some 35 MMBbl oil have been produced up to January 2019. 2 MMBbl of oil have also been produced from each of NEAG 3 and NEAG 5. No production has taken place from NEAG 4, which is primarily a gas field and is somewhat stranded in the centre of the NEAG area. Future development plans focus on the implementation and expansion of water flood in the NEAG 1 and NEAG 5 Fields and infill drilling at NEAG 2 & 3.

2.8.1.1 Structure and Trap

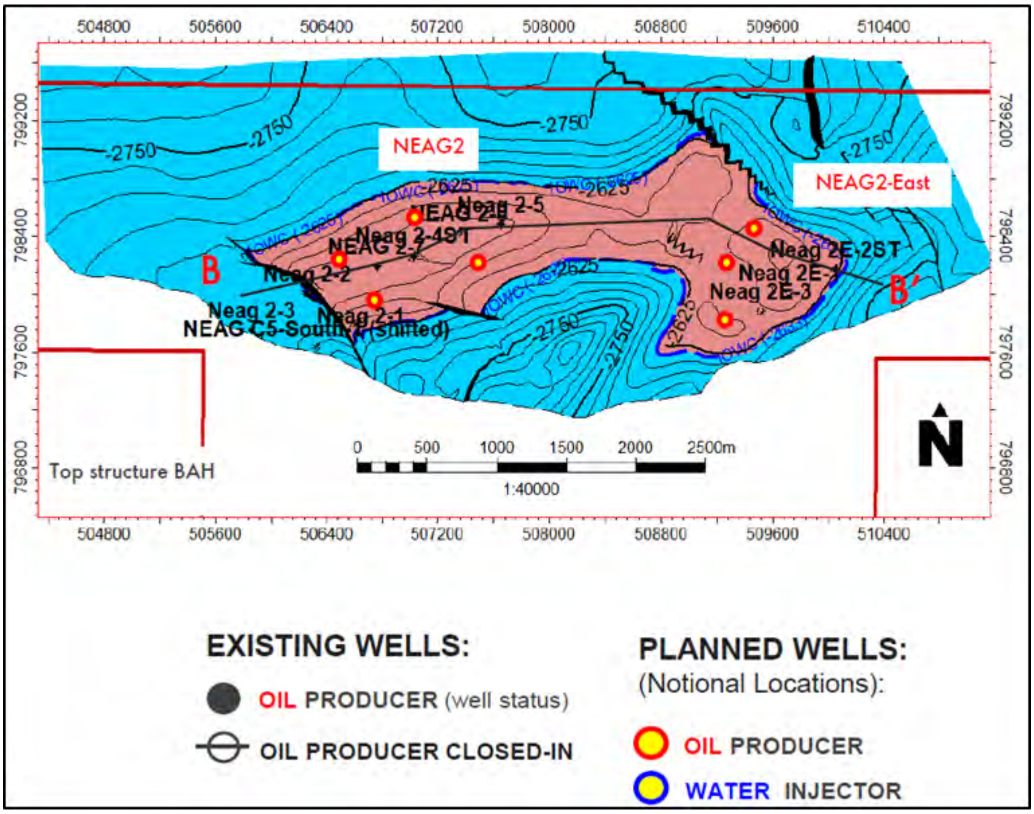
Trapping mechanisms are structural with either 3 or 4-way closed structures, variably relying on up-dip faults for ultimate seal. NEAG 1 consists of two Fields, named Al Fadl and Al Qadr. NEAG 2 is further divided into main and eastern areas across a structural saddle. NEAG 3, 4 and 5 each consist of a single hydrocarbon accumulation. Figure 86 to Figure 90 present maps of each of the Fields in the NEAG Ext. Figure 91 and Figure 92 present structural maps of the JG and Sheiba Fields in NEAG Tiba.

Figure 86: NEAG 1 (Al Fadl & Al Qadr Fields) – Bahariya Reservoir Level



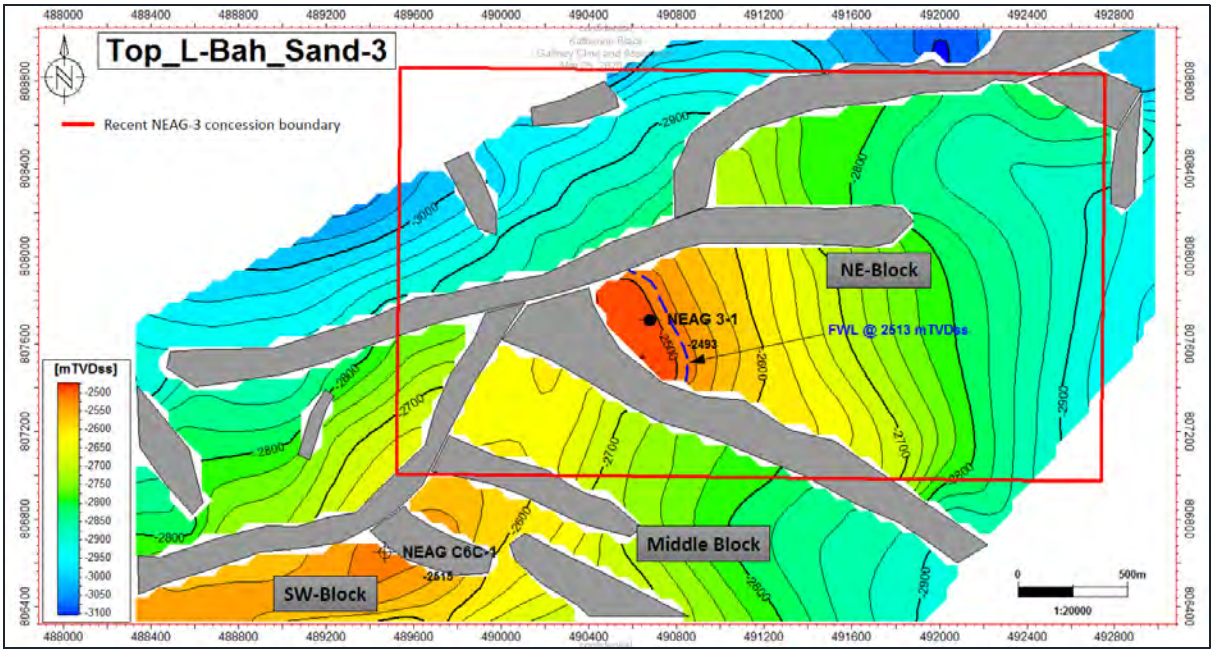
Source: Vendor VDR

Figure 87: NEAG 2 (East & West Areas) – Bahariya Reservoir Level



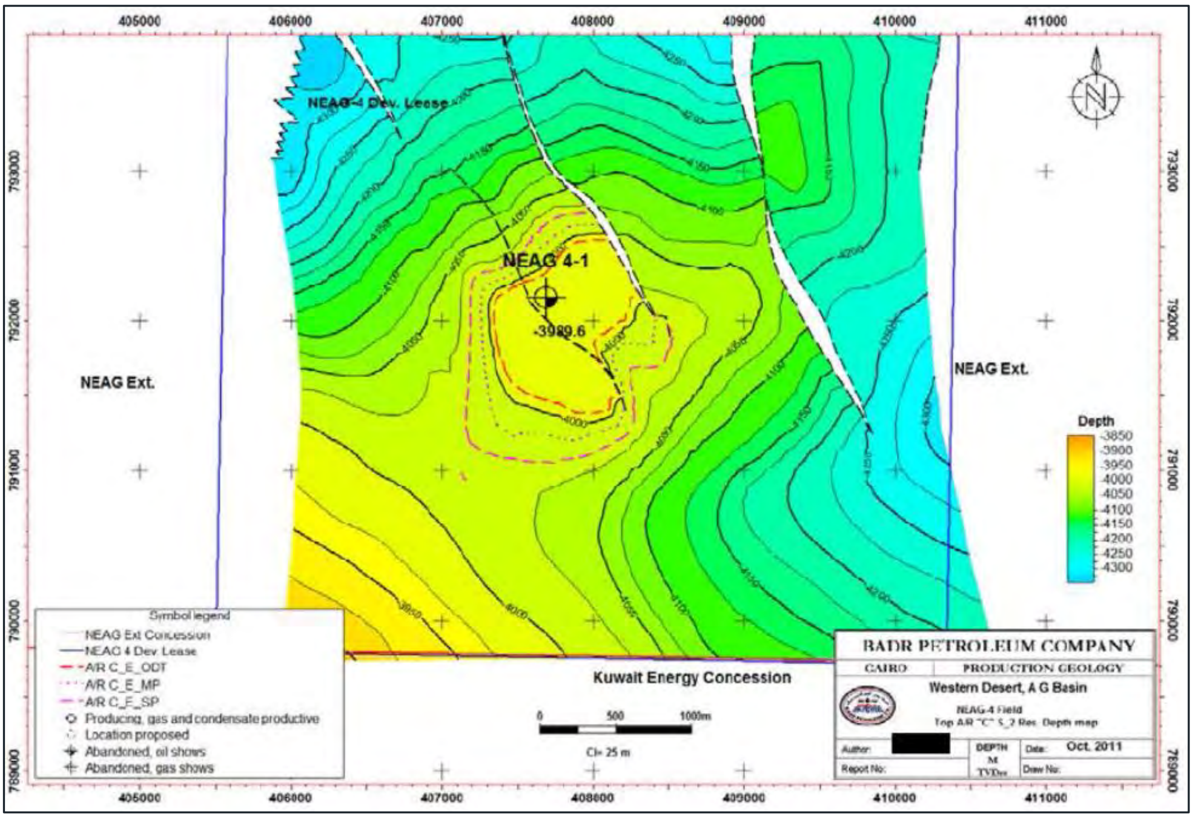
Source: Vendor VDR

Figure 88: NEAG 3 – Bahariya Reservoir Level



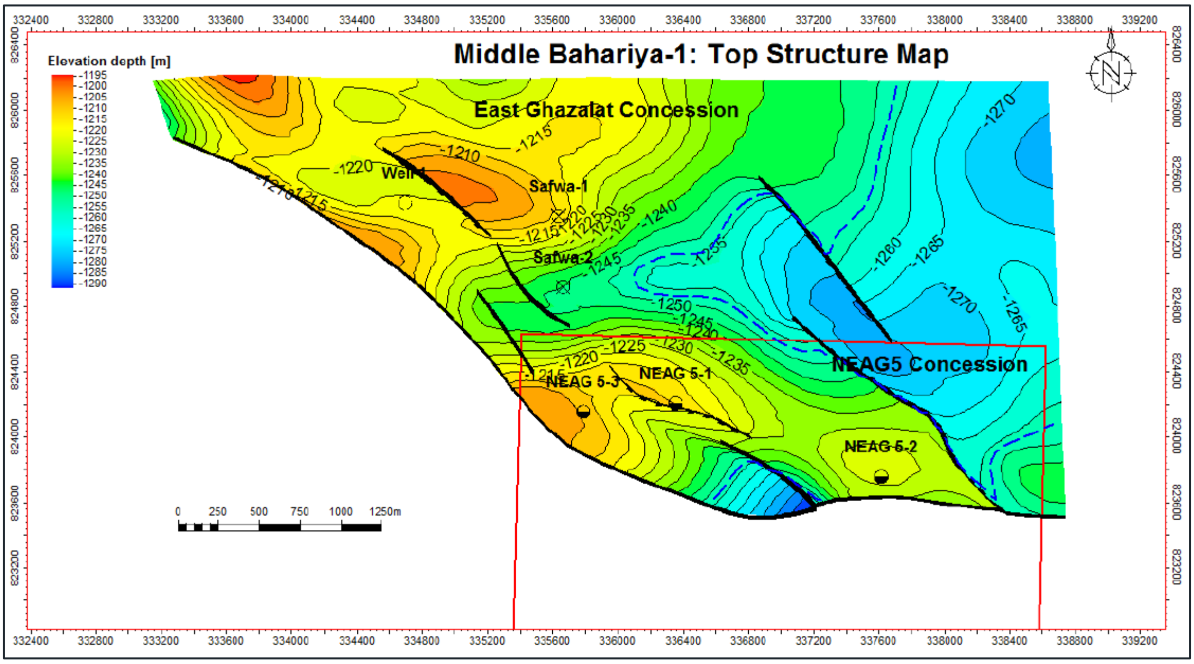
Source: Vendor VDR

Figure 89: NEAG 4 – Abu Roash 'C' Reservoir Level



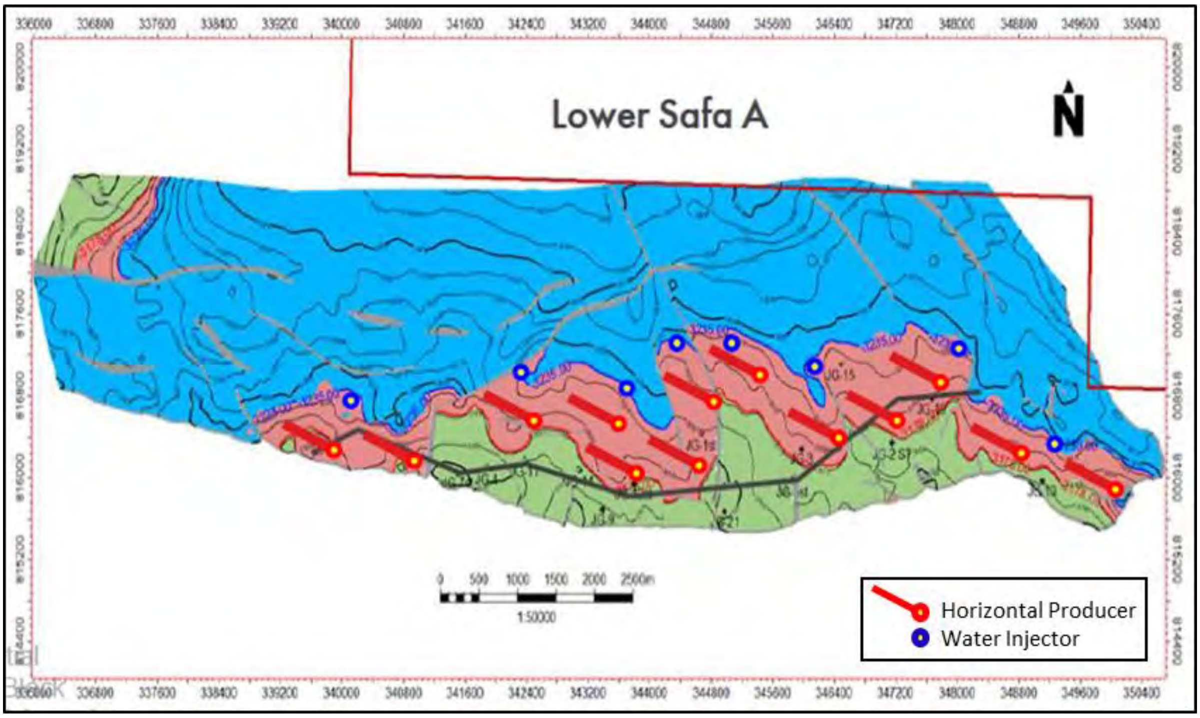
Source: Vendor VDR

Figure 90: NEAG 5 – Bahariya Reservoir Level



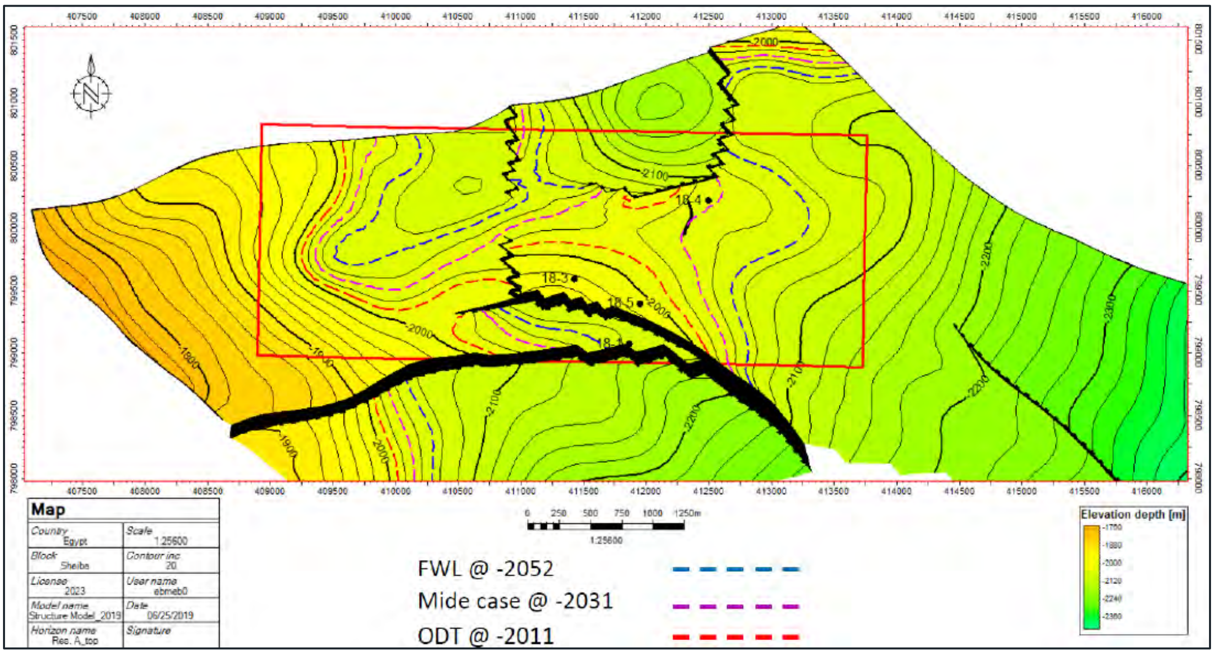
Source: Vendor VDR

Figure 91: NEAG Tiba (JG Field) – Lower Safa Reservoir Level



Source: Vendor VDR

Figure 92: NEAG Tiba (Sheiba Field) – Bahariya Reservoir Level



Source: Vendor VDR

2.8.1.2 Reservoir

The primary reservoirs in NEAG 1, 2, 3 and 5 are the shallow marine to terrestrial clastic sandstones of the Cenomanian aged, Bahariya interval. Secondary reservoirs in NEAG 1 and 2 are the tight Albian, Kharita sandstones. NEAG 4 has reservoirs in the Abu Roash C & E intervals.

The primary reservoirs at JG are the Middle Jurassic, Upper Safa sandstones, which lie at a depth of approximately 3,100 mTVDss. Secondary reservoirs at JG are the Lower Safa sandstones. At Sheiba, the primary reservoirs are in the Bahariya interval (Cenomanian). The Paleocene to Eocene aged, Apollonia carbonate (chalk) reservoirs are the primary target at the JD Field. The JG and Sheiba Fields consist of hydrocarbon accumulations in single structures, where the trapping mechanism is 3-way dip closure, relying on major faults for ultimate seal. The precise trapping structure at JD is yet to be fully understood, but is likely to be a combined trapping mechanism with stratigraphic and structural elements.

2.8.1.3 Reservoir and Fluid Properties

Representative PVT data are presented in Table 95. Reported CO_2 content is moderately low at 2.1 mol% at JG-9. Apart from some evidence of anomalously high temperatures in the shallow Bahariya Formation reservoirs, pressure and temperature gradients are normal.

Table 95: NEAG Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
NEAG JG-9	Not known	Not known	Not known	Not known	Not known	Not known	67	Not known	0.71

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
NEAG C3-1	BAH	1,075	64.4	1,700	253	1.05	45	1.82	40
NEAG C4-1	BAH	1,150	64.4	1,700	305	1.07	72	1.50	41
NEAG C5-1	BAH	2,650	93.6	3,924	Not known	1.13	116	Not known	43
NEAG C9-1-1	BAH	1,025	67.2	1,823	319	1.13	133	1.57	38
NEAG JG-2	KHAT	3,325	114.4	4,851	4,640	1.68	1419	0.33	38
NEAG JG-7	LSAF	3,250	114.4	4,830	2,256	1.50	804	0.35	42
NEAG JG-13	USAF	2,950	106.7	4,371	3,335	1.55	1085	Not known	36

2.8.1.4 Production Facilities

The NEAG area has three remote processing facilities, namely:

- o NEAG-1 facility;
- o NEAG-2 Early Production Facility (EPF); and
- o NEAG-JD facility.

The NEAG-2 EPF dewaters the NEAG-2 area production fluids before co-mingling them with the NEAG-1 production fluids for processing at the NEAG-1 facility. The NEAG-1 facility has a design capacity of 6 Mbpd of condensate. The NEAG-2 EPF has a design capacity of 24 Mbpd of gross liquids (condensate and water). The produced water separated at NEAG-2 EPF is disposed of via evaporation ponds. The NEAG-1 facility heats the condensate and further separates out produced water from the condensate stream, with any associated gas vented to atmosphere. The produced water from NEAG-1 is disposed of via soakaways. The treated condensate from NEAG-1 is exported to the Karama gathering centre, before forwarding to the Qarun station and on to the terminal at Dashour for offloading to tanker for export.

Production fluids from NEAG-JG and NEAG-5 are gathered at the NEAG-JG facility. The NEAG-JG facility separates the produced water from the condensate stream and disposes of it via reinjection. The dewatered condensate and associated gas is exported via multiphase pipeline to the BED3 processing plant for further treatment.

2.8.2 HIIP

Where sufficient information was provided in the VDR and or the vPDR, GaffneyCline carried out an independent assessment of the HIIP for the volumetrically significant reservoirs. As far as data allowed, a Crystal Ball model was generated for each of the reservoirs and fields.

Petrophysical parameters where spot checked at two wells. Well ALF-41 from the Al Fadl Field in NEAG 1 and well JG-23 from the JG Field in NEAG Tiba. Reservoir average values were further spot checked by analysis of well logs and or zone averages in any Petrel models that were available.

The ALF-41 and JG-23 wells had input logs and petrophysical interpretation reports, the wells also had top depths provided. The input logs typically included GR, Density, Neutron, Resistivity & Photoelectric Factor.

GaffneyCline relied on input parameters, such as grain density, formation water salinity, Archie parameters etc., provided in the core analysis reports, where available. If such data were unavailable, then the parameters were derived by GaffneyCline independently using provided logs, from cross-plots, or from neighbouring wells, where such parameters were known. The main intervals of interest were Lower Safa in JG-23, Bahariya in ALF-41.

Gross rock volume (GRV) values presented in the VDR were checked by running any Petrel models or generating estimates of map based GRV using the volumetric tool in Petrel and any associated structural surfaces. Structural surfaces were also checked to see if they honoured well control.

Relatively wide values of reservoir parameters were used and the ranges were made wider if there was sparse well information or if the reservoir quality was particularly variable. Models were populated using log normal or normal parameter distributions. Input variables were input to Crystal Ball models as the P90, P50 and P10 values.

Each of the models was run with 100,000 trials and the resulting P90, P50 and P10 results were extracted and used as the Low, Best and High Case estimates respectively. Table 96 and Table 97 present comparisons of the Operator's STOIIP estimates, the Vendor's estimates and GaffneyCline's independent estimates. GaffneyCline did not derive independent estimates for minor reservoirs or where data in the VDR and vPDR was not sufficient. GaffneyCline was unable to validate the estimate of 221 Bscf in NEAG JG LSA from the Petrel model provided. However, 195 Bscf has reportedly already been produced from this reservoir, and the Vendor carries a GIIP estimate of 233 Bscf. No meaningful data were provided in order to independently verify in-place hydrocarbon estimates at Sheiba and JD.

Table 96: Comparison of HIIP Estimates – NEAG Ext

(a) Oil (MMBbl)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG 1 ALF [BAH]	58	58	34	51	73
NEAG 1 ALQ [BAH]	19	17	13	20	28
NEAG 2 Main [BAH]	45	42	24	40	61
NEAG 2 East [BAH]	6	8	5	7	11
NEAG 3 [BAH]	4	N/A	N/A	N/A	N/A
NEAG 4 [ARC/E]	4	N/A	N/A	N/A	N/A
NEAG 5 [BAH]	17	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

(b) Gas (Bscf)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG 4 [ARC/E]	56	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Table 97: Comparison of STOIIP Estimates – NEAG Tiba

(a) Oil (MMBbl)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG JG [LSA]	77	83	50	72	100
NEAG JG [LSC]	20	24	15	21	29
NEAG JG [LSA0]	8	5	3	5	6
NEAG JG [US]	11	15	11	15	20
NEAG Sheiba [BAH]	8	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

(b) Gas (Bscf)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG JG [LSA]	221	233	N/A	N/A	N/A
NEAG JD [APP]	352	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Overall, there appears to be relatively consistent volumetric estimates across the different methods and companies.

2.8.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 98.

In the NEAG Tiba area, the JG Field has been the primary focus to date. Gas phase hydrocarbons have been produced from all reservoirs at JG, a total of some 195 Bcf up to January 2019. A very small amount of production has taken place from the Sheiba Field, which is located in the central part of the NEAG area and is somewhat stranded. The JD Field contains a potentially significant volume of gas, in the shallow Apollonia reservoirs, but is yet to be exploited and represents upside. The Operator has stated the plan for future work will be to focus on exploitation of the oil rim at JG through horizontal wells and water flood. A small number of infill wells are also planned for the Sheiba Field. The JD Field is likely to require further appraisal.

Table 98: NEAG: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NEAG (Tiba)			
JG NFA	JG NFA		Reserves
JG Infill	JG Infill		Reserves and Contingent Resources
Sheiba infill	Sheiba infill		Reserves
General infill	Not included	All development activity viewed as covered by other categories.	N/A
JD C2E	Near Field Exploration	Only includes Apollonia gas development	Contingent Resources
JG C2E			Prospective Resources
Upsides	Not included	All development activity viewed as covered by other categories.	N/A
NEAG (Ext)			
NEAG 1 NFA	NEAG 1 NFA		Reserves
NEAG 2 NFA	NEAG 2 NFA		Reserves
NEAG 3 NFA	NEAG 3 NFA		Reserves
NEAG 5 NFA	NEAG 5 NFA		Reserves
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
NEAG 1 infill	NEAG 1 infill		Reserves
NEAG 2 infill	NEAG 2 infill		Reserves
NEAG 3 infill	NEAG 3 infill		Reserves
NEAG 5 infill	Not included	Minor activities with insufficient materiality	N/A
General infill			
NEAG 1 C2E			
NEAG 2 C2E			
GW C2E			

2.8.4 Historical Field Performance

2.8.4.1 NEAG Ext

NEAG 1 includes Al Fadil and Al Qadr. Al Fadil production started in 2008 with wells NEAG 1-1 and 2. Peak production of 5,000 bopd was reached in 2015. Current production is 1,700 bopd with a watercut of 76%.

AL Qadr production started in 2008 and peaked in 2009 with a maximum oil rate of 2,600 bpd. The current oil production is approximately 500 bopd with a watercut of 80%.

Figure 93 and Figure 94 show the oil production history and watercut for Al Fadil and Al Qadr reservoir respectively.

Figure 93: Historical Oil Production Rate and Watercut, Al Fadil

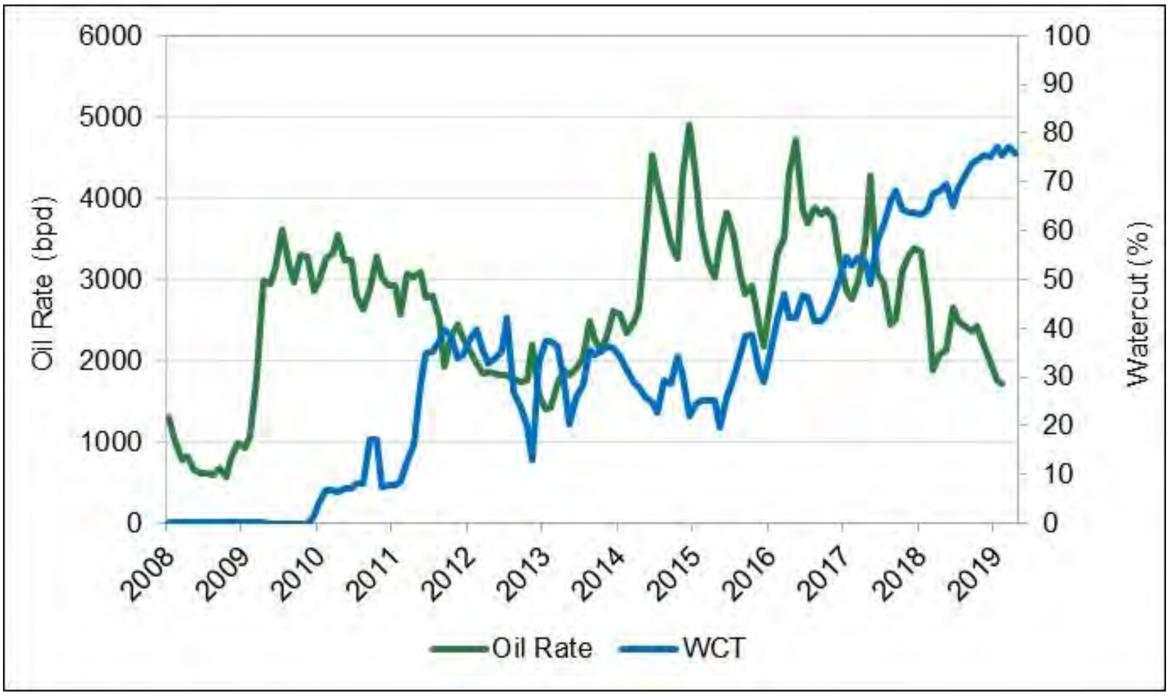
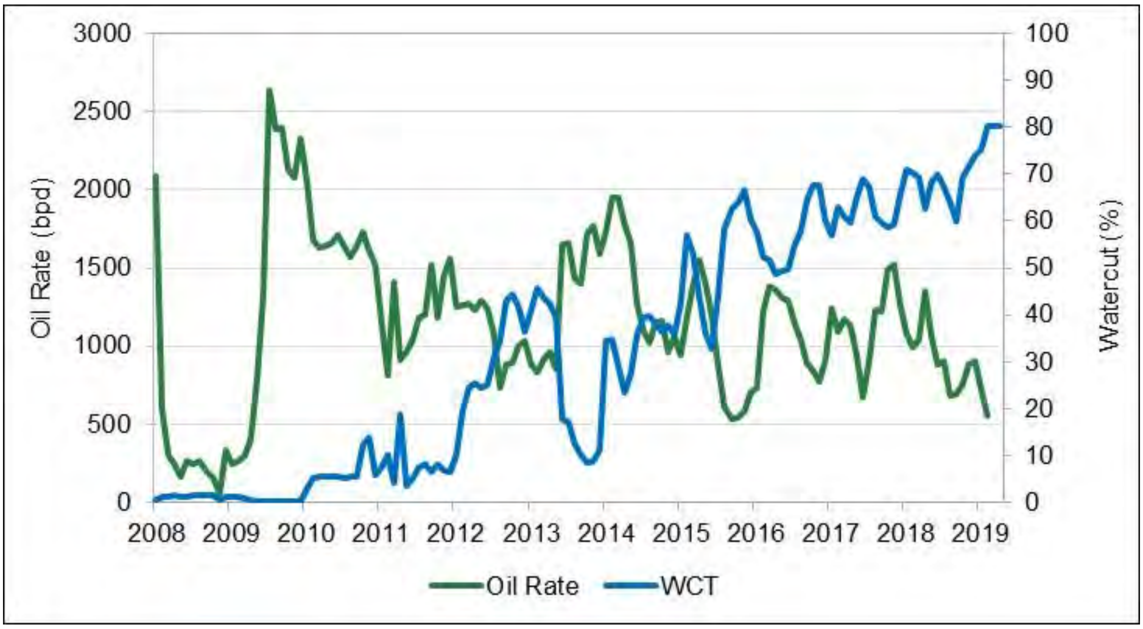


Figure 94: Historical Oil Production Rate and Watercut, Al Qadr



NEAG 2 includes NEAG 2 Main and NEAG 2 East. Production started in 2010 with well NEAG C5-1, and was ramped up in 2011 by bring well NEAG C5-2 on stream. Peak production of 13,600 bopd was reached in 2016 with the drilling of wells NEAG C5-4 and NEAG C5-5. Currently production is from four wells with an average rate of 3,950 bopd and a watercut of 85.5%.

NEAG 3 production commenced in 2010 with the drilling of well NEAG C6-1 in the Bahariya reservoir. A further well (NEAG C6-2) was drilled in the Bahariya formation in 2018. The Field is currently producing only from one well (NEAG C6-2) at an average rate and watercut of 950 bopd and 65% respectively.

NEAG 5 production commenced in 2013 from the NEAG 5-1 well. The field is currently producing with three wells with an average rate and watercut of 500 bopd and 39% respectively.

Figure 95, Figure 96 and Figure 97 show the oil production history and watercut for NEAG 2, NEAG 3 and NEAG 5 reservoir respectively.

Figure 95: Historical Oil Production Rate and Watercut, NEAG 2 (Main and East)

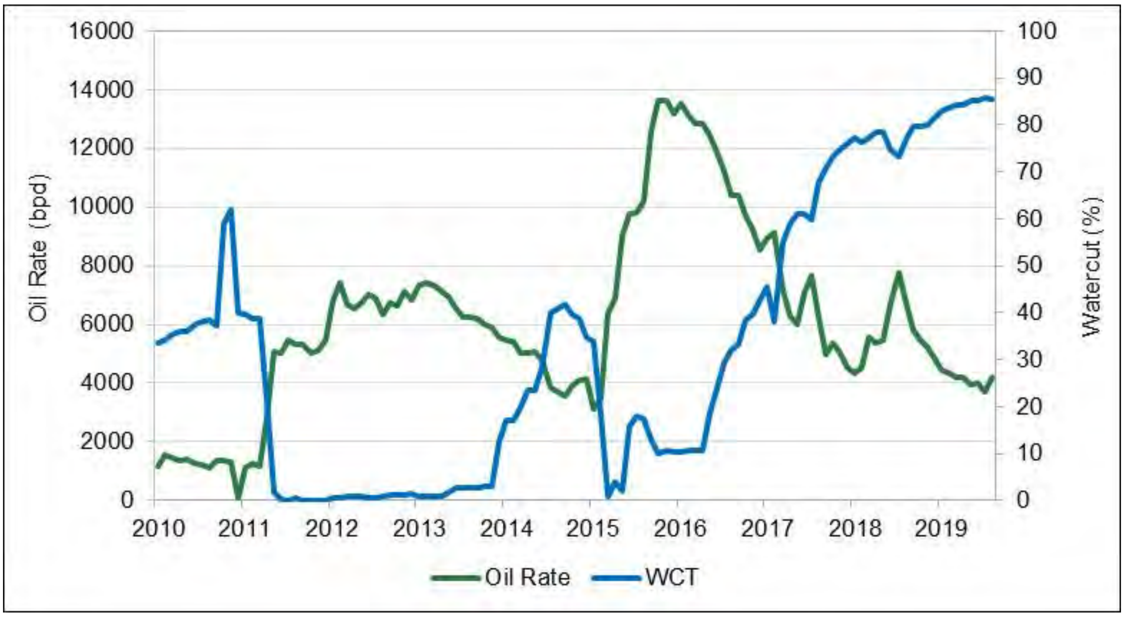


Figure 96: Historical Oil Production Rate and Watercut, NEAG 3

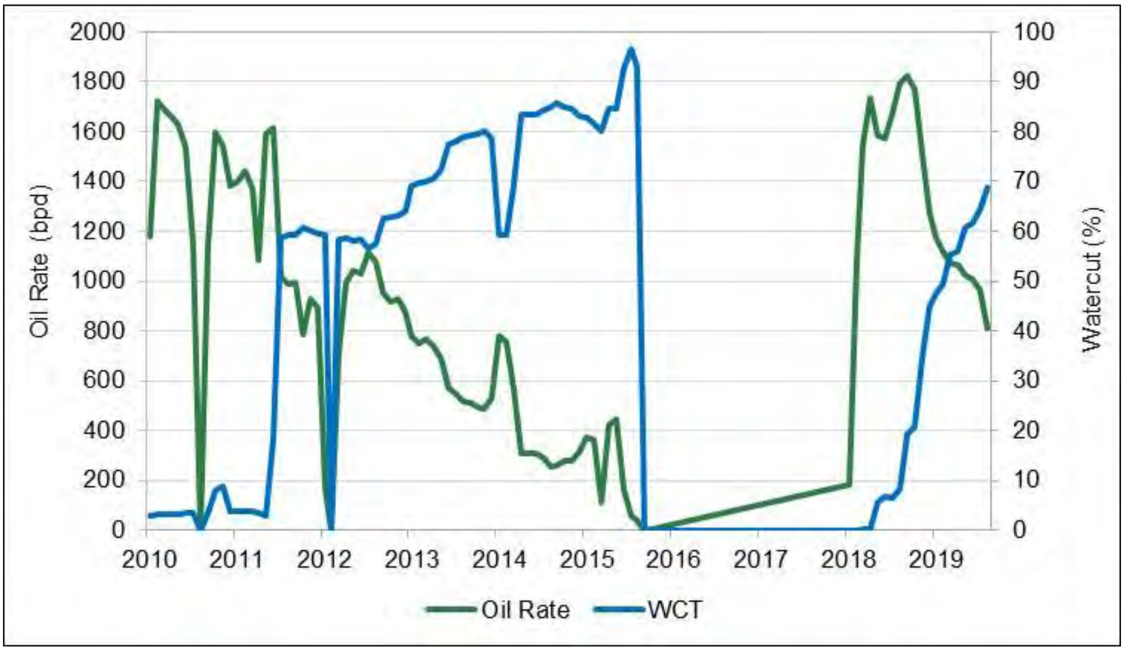
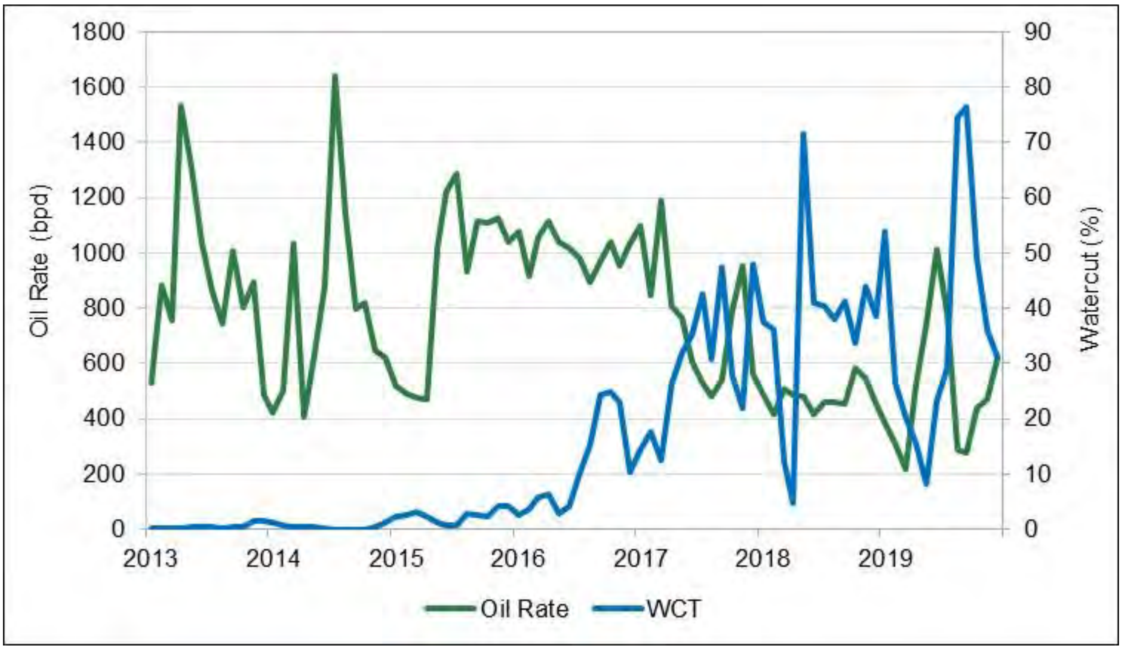


Figure 97: Historical Oil Production Rate and Watercut, NEAG 5



The cumulative oil production for NEAG Ext, along with recent rates are summarized in Table 99.

Table 99: NEAG Ext Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Average Oil Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	bopd	bwpd
NEAG 1 (Al Fadil)	17	1.10	1,700	6,140
NEAG 1 (Al Qadr)	4	4.76	505	2,560
NEAG 2	4	2.15	3,960	23,300
NEAG 3	1	1.65	929	1,720
NEAG 5	3	1.96	510	320
Total	**29**	**11.62**	**7,604**	**34,040**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.8.4.2 NEAG Tiba

The developed reservoirs in NEAG Tiba are quite mature. Production from NEAG Tiba JG (the currently active field) started in 2002 with well NEAG JG. JG reached a peak rate of 7,900 bopd in 2009. Water breakthrough in LSC wells was observed in 2009 in which the watercut increased from zero to 70%. Three wells stopped producing in 2019.

The historical production for JG and Sheiba fields is shown in Figure 98 and Figure 99.

Production in NEAG Sheiba commenced in 2004 from two wells (SHB-18-1 & SHB-18-3) in the Bahariya formation. A further well was drilled in 2005 (SHB-18-5). Production declined and finally ceased in 2014.

Figure 98: NEAG Tiba JG Historical Oil Production Rate and Watercut

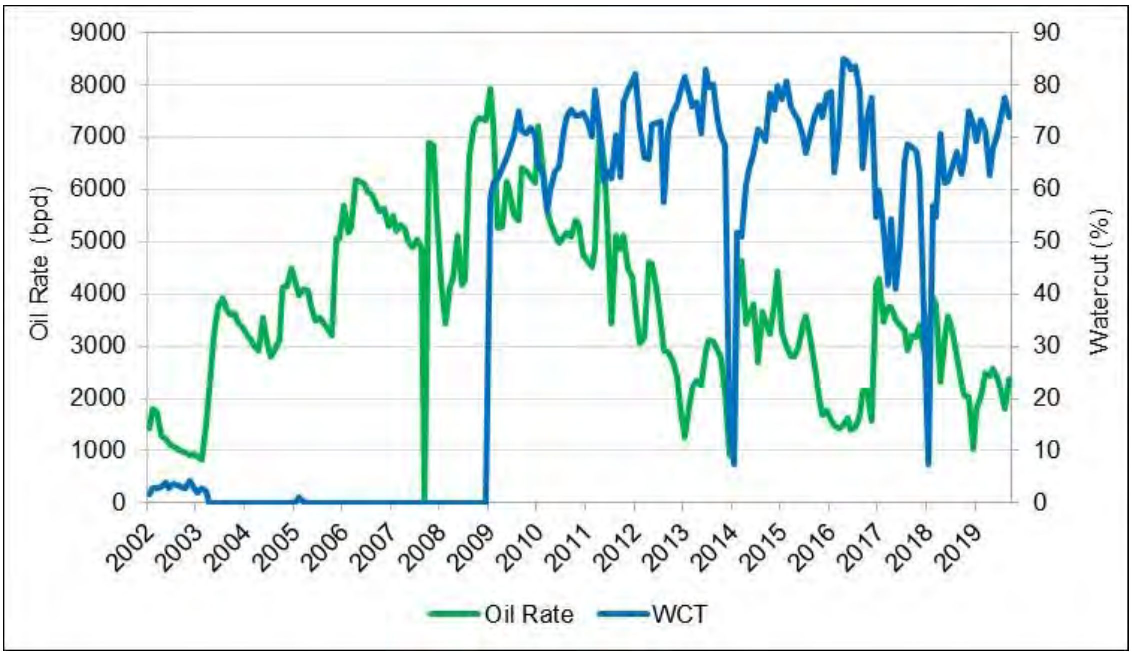
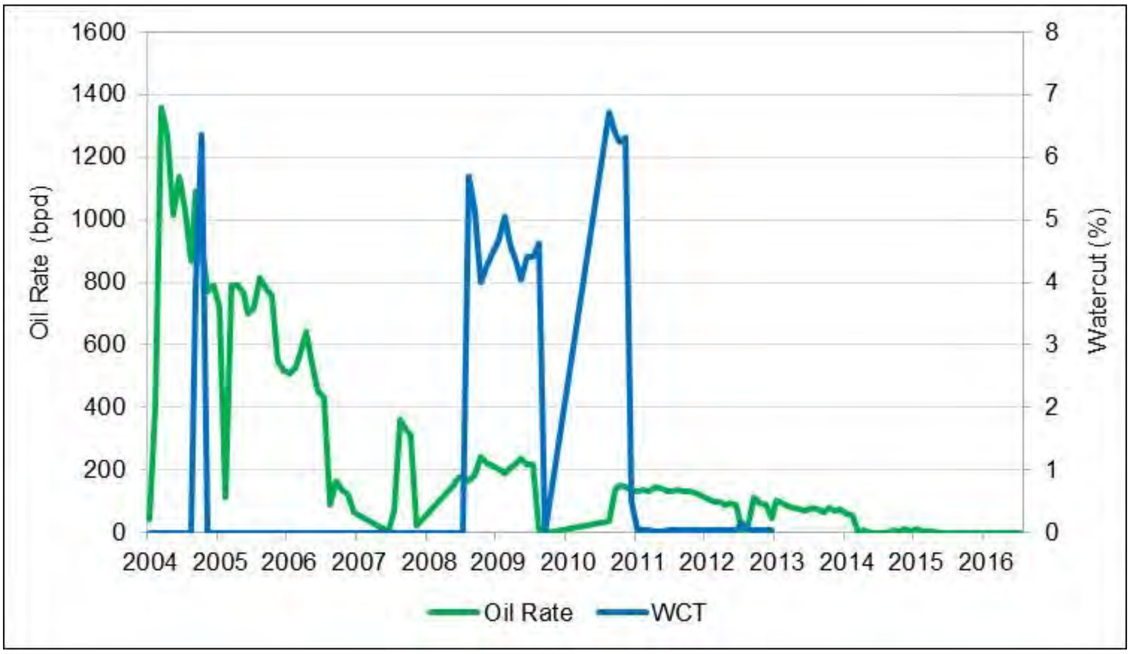


Figure 99: Historical Oil Production Rate and Watercut, NEAG Sheiba



The cumulative production, along with recent rates for NEAG Tiba fields are summarized in Table 100.

Table 100: NEAG Tiba Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
JG	8	24.0	194.8	2,164.8	13.2	6,194.3
Sheiba	0	1.0	0.5	0.0	0.0	0.0
Total	**8**	**25.0**	**195.3**	**2,164.8**	**13.2**	**6,194.3**

Note:

1. Totals may not exactly equal the sum of individual entries due to rounding.

2.8.5 Field Development Plan

2.8.5.1 NEAG Ext

The Consortium's business plans for the NEAG 1 fields (Al Fadil and Al Qadr) includes the following activities:

- Seven infill wells and three injectors in Al Fadil;
- Three injectors in Al Qadr.

The schedule and number of new production wells are summarized in Table 101.

The infill well locations for NEAG 1 (Al Fadil and Al Qadr) are shown in Figure 86.

Table 101: NEAG 1 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	6	1	0	**7**
Injection Wells	0	0	3	3	0	**6**
Total	**0**	**0**	**9**	**4**	**0**	**13**

The future development plan for NEAG 2 fields (Main and East) includes the following activities:

- Four infill wells in NEAG 2 Main;
- Three infill in NEAG 2 East.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of new production wells are summarized in Table 102.

The infill well locations for NEAG 2 (East and West Areas) are shown in Figure 87.

Table 102: NEAG 2 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	7	0	**7**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**0**	**7**	**0**	**7**

In NEAG 3, there is just 1 producer planned to be drilled, as shown in Table 103.

Table 103: NEAG 3 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	1	0	0	**1**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**1**	**0**	**0**	**1**

2.8.5.2 NEAG Tiba

The Consortium's future development plan for NEAG Tiba JG field includes the following activities:

- Three vertical producers and two injectors in the NEAG JG Lower Safa O (LSO) formation;
- Nine Horizontal Infill wells in NEAG JG LSA, along with two vertical injectors.

The schedules for these activities are shown in Table 104 and Table 105.

Table 104: NEAG Tiba JG LSO Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	1	0	0	2	**3**
Injection Wells	0	1	0	0	1	**2**
Total	**0**	**2**	**0**	**0**	**3**	**5**

Table 105: NEAG Tiba JG LSA Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	1	0	3	3	**9**
Injection Wells	**0**	0	0	2	4	**6**
Total	**1**	**1**	**0**	**5**	**7**	**15**

The infill well locations for NEAG Tiba JG (LSA) are shown in Figure 91.

Three infill wells are planned in NEAG Sheiba field. The proposed drilling schedule for is presented in Table 106.

Table 106: NEAG Sheiba Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	3	0	0	0	**3**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**3**	**0**	**0**	**0**	**3**

2.8.6 Production Forecasts

2.8.6.1 NEAG Ext

GaffneyCline carried out its own analysis using a combination of DCA for existing wells and type wells to estimate the performance of the planned new infill wells.

Forecasts were produced for the period from 2020 to the expiry of the PSAs (varying from November 2032 to November 2036).

Table 107 shows the remaining technically recoverable volumes for NEAG 1, NEAG 2, NEAG 3 and NEAG 5.

Table 107: Remaining Technically Recoverable Oil Volumes, NEAG Ext, as at 31st December 2019

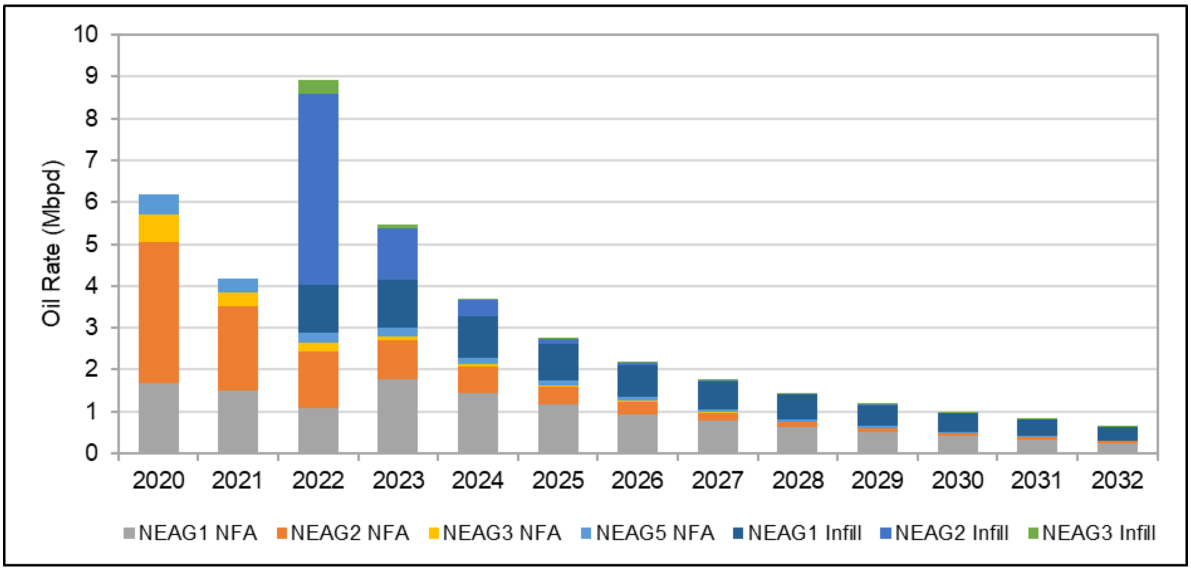
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NEAG 1	5.7	7.5	9.1
NEAG 2	4.0	5.8	8.7
NEAG 3	0.6	0.7	0.9
NEAG 5	0.5	0.7	0.8
Total	**10.8**	**14.7**	**19.5**

Notes:

1. The volumes in this table are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

The Best Case oil production forecasts for NEAG Ext are shown in Figure 100 by activity.

Figure 100: Best Case Oil Production Forecast, NEAG Ext

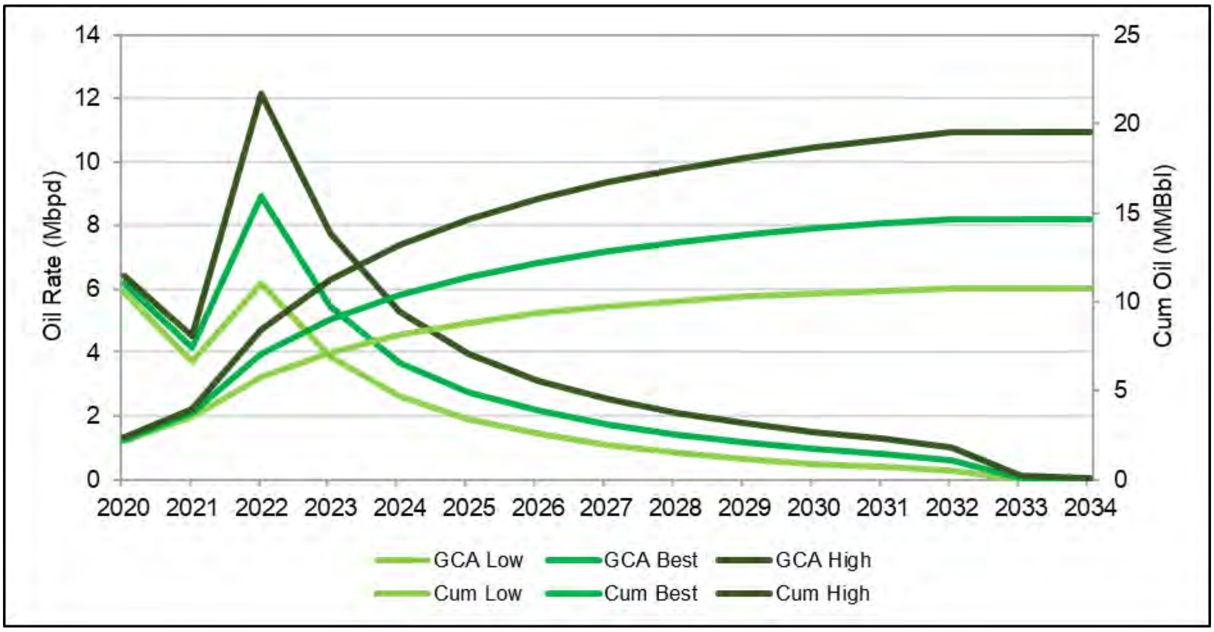


Note:

1. The volumes in this figure are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.

Figure 101 shows the Low, Best and High production forecasts for NEAG Ext.

Figure 101: Oil Production Forecasts, NEAG Ext



Note:

1. The volumes in this figure are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.

2.8.6.2 NEAG Tiba

GaffneyCline carried out its own analysis using a combination of DCA for existing wells and type wells to estimate the performance of the planned new infill wells.

Forecasts were produced for the period from 2020 to the expiry of the PSAs, in February 2027 for JG and May 2029 for Sheiba.

Table 108 and Table 109 show the remaining technical recoverable volumes for JG and Sheiba.

Table 108: Remaining Technically Recoverable Oil Volumes, NEAG Tiba as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NEAG Tiba JG	5.8	8.3	11.3
NEAG Sheiba	0.2	0.7	1.4
Total	**6.0**	**9.0**	**12.7**

Notes:

1. The volumes in this table are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Table 109: Remaining Technically Recoverable Gas Volumes, NEAG Tiba as at 31st December 2019

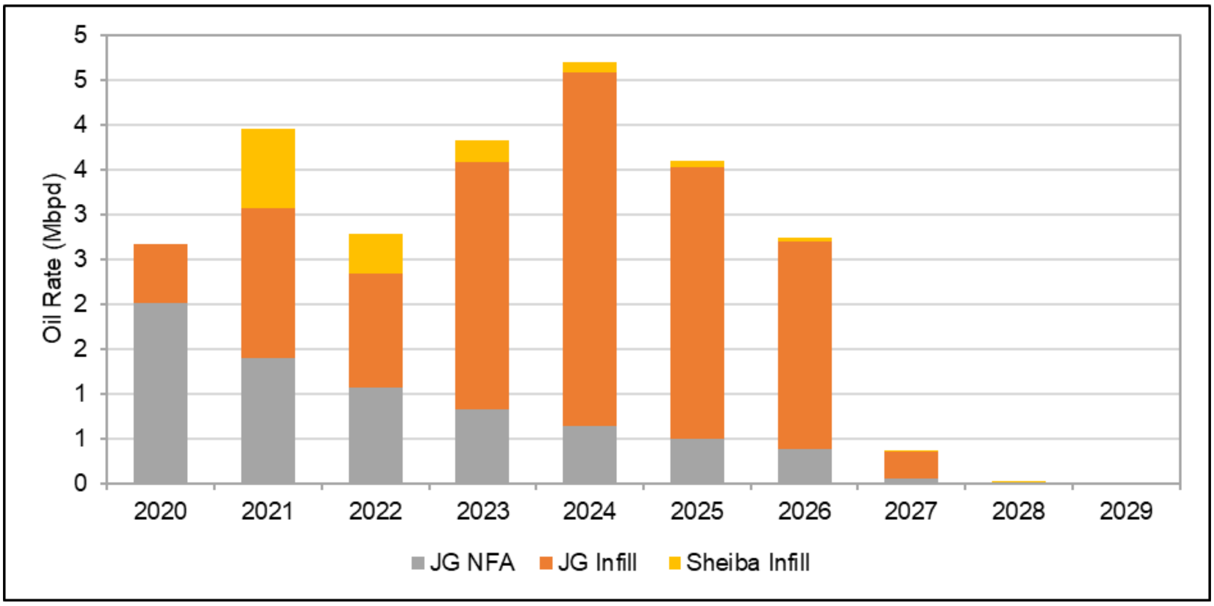
Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
NEAG Tiba JG	16.6	22.6	30.4
NEAG Sheiba	0.2	0.7	1.8
Total	**16.8**	**23.3**	**32.2**

Notes:

1. The volumes in this table are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 102 and Figure 103 show the Best Case production forecasts for NEAG Tiba, by activity.

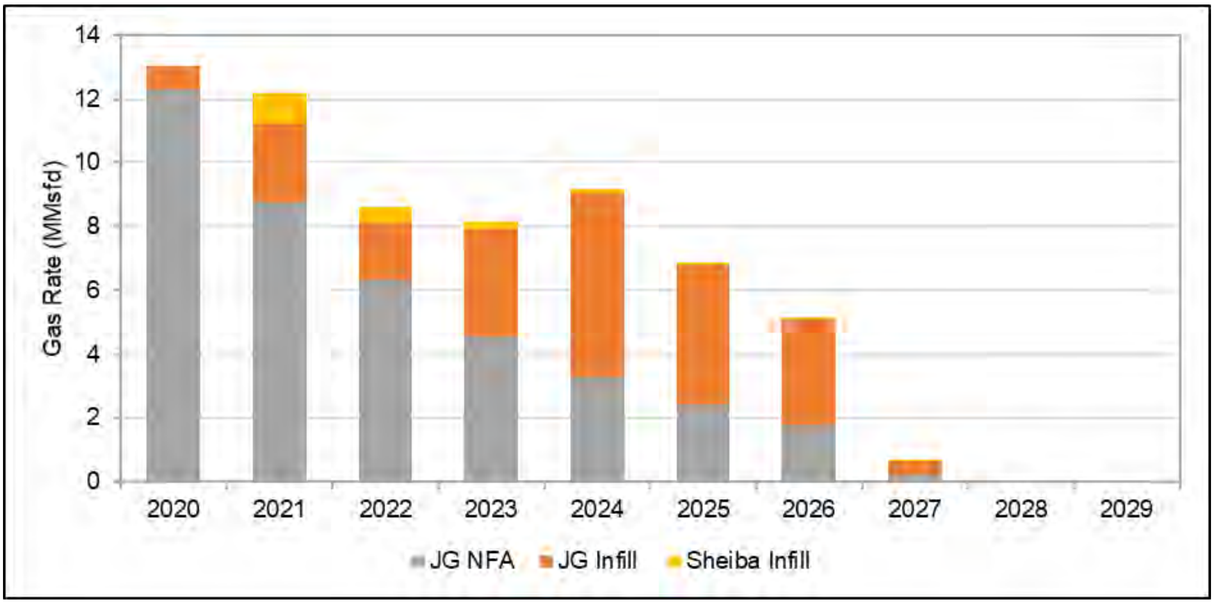
Figure 102: Best Case Oil Production Forecast, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 103: Best Case Gas Production Forecast, NEAG Tiba

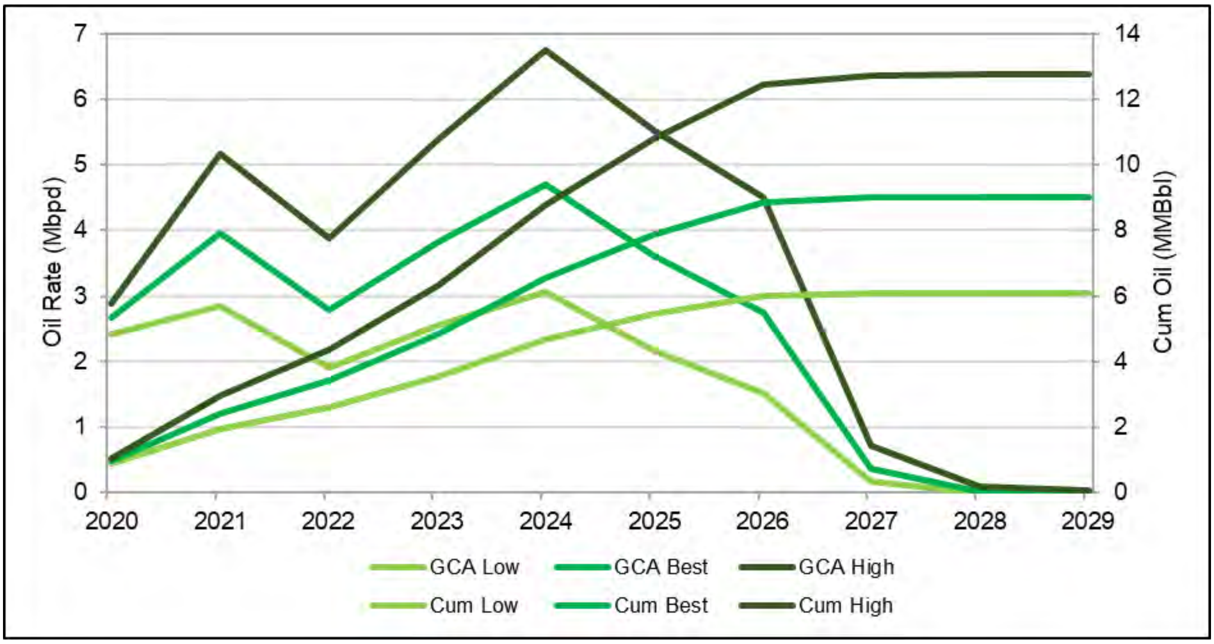


Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 104 and Figure 105 show the Low, Best and High oil and gas production forecasts for NEAG Tiba.

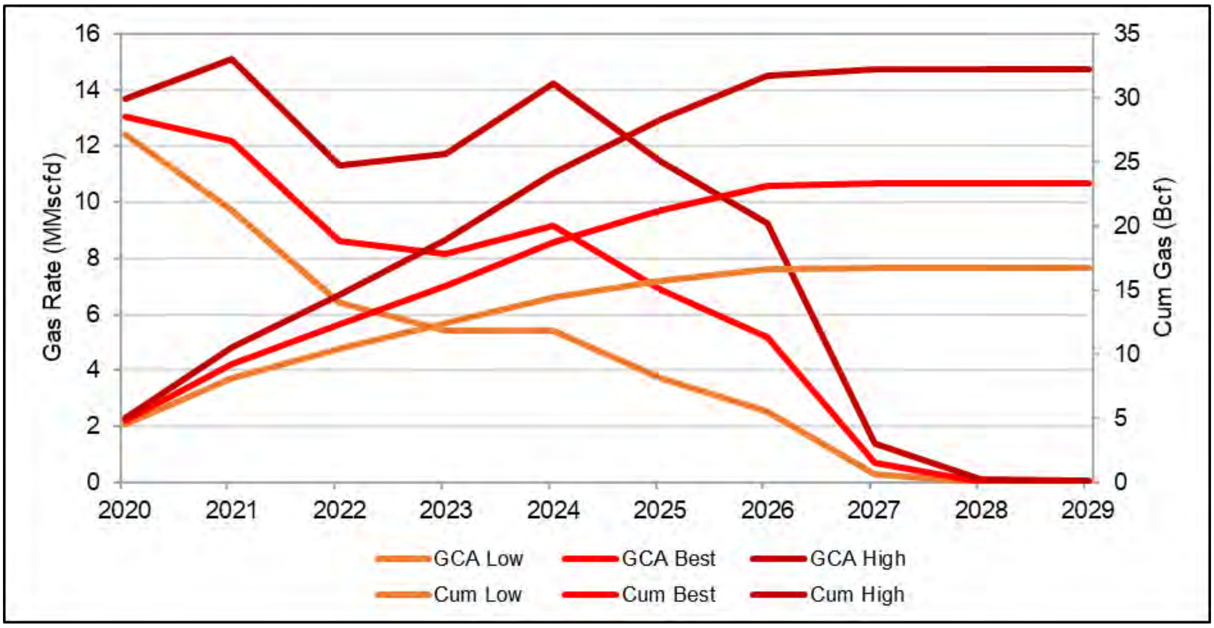
Figure 104: Oil Production Forecasts, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 105: Gas Production Forecasts, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

2.8.7 Contingent Resources

Six wells in the NEAG Tiba JG which are envisaged more than 5 years in the future (2025 onwards) have been considered as Contingent Resources. These wells include four horizontal wells in the Lower Safa of NEAG Tiba JG and two vertical wells in the Upper Safa. The Contingent Resources also include the effect of two water injectors in the Lower Safa, two water injectors in the LSO and one water injector in the Upper Safa.

Table 110 shows the Low, Best and High Gross Contingent Resources for the NEAG Tiba.

Table 110: Gross Oil and Gas Contingent Resources, NEAG Tiba, as at 31st December 2019

(b) Oil and Condensate

1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
0.9	1.0	1.5

(a) Natural Gas

1C (Bscf)	2C (Bscf)	3C (Bscf)
1.2	1.8	3.1

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

3 Capital Expenditure (CAPEX) and Operating Expenditure (OPEX)

GaffneyCline has conducted a review of the Consortium's proposed CAPEX and OPEX estimates for the concession areas. The review was based upon GaffneyCline's understanding of the market conditions, the Consortium's operating philosophy and forward looking development plans.

3.1 CAPEX Program

There are three main areas of CAPEX for the concession areas in support of the fields' future production and development plans:

- Well and hook-up costs;
- Facilities Projects; and
- Asset Integrity/HSSE costs.

3.2 Well and Hook-up Costs

Table 111 provides a summary of estimated development wells for each of the different concession areas. The well costs have been benchmarked by GaffneyCline against the current Vendor's operating asset performance, and adjusted considering the market conditions (e.g. rig rates and contract renegotiation) and the Consortium's analogous drilling performance in the Western Desert.

There is a number of well reactivations to support the Consortium's production plan during the period of 2021-2023. These reactivation costs are accounted for in the OPEX as an additional expenditure on top of the "business as usual" workover costs included in the baseline operating cost.

Table 111: Development Well CAPEX Estimates

Concession Area	Description	CAPEX US$ MM
Obaiyed		
Lower Safa Flank	Production Well (Horizontal)	6.0
Lower Safa Core	Production Well (Vertical)	2.8
Lower Safa Core	Production Well (Horizontal)	5.3
Upper Safa	Well Recompletions	1.1
NM		
Lower Safa	Production Well (Vertical)	4.2
NUMB		
Lower Safa	Production Well (Vertical)	4.2
BED 3		
BED3, BED15, BED18	Production Well (Vertical)	1.5
BED3, BED18	Water Injection Well (Vertical)	1.0
BED 2		
BED2	Production Well (Horizontal)	3.5
BED 16	Production Well (Vertical)	1.5
Sitra		
Sitra3	Production Well (Horizontal)	3.5
Sitra8, SitraC30, SitraC3	Production Well (Vertical)	1.8
Sitra8	Water Injection Well (Vertical)	1.0
AESW		
Bagha, Al Magd, Assil	Production Well (Vertical)	1.5
Al Karam (Note 2)	Production Well (Vertical)	9.0
Bagha, Al Magd	Water Injection Well (Vertical)	1.0
NAES		
BTE	Production Well (Vertical)	6.0
NEAG		
NEAG1, NEAG2, NEAG3	Production Well (Vertical)	1.5
NEAG-JG	Production Well (Horizontal)	3.7
NEAG JG	Production Well (Vertical)	2.4
NEAG1	Water Injection Well (Vertical)	1.0

Notes:

1. All well costs include contingency
2. Al Karam wells consider efficiency improvements year on year based on feedback from Vendor on performance of BTE-4 well new design. The improvements are applied as a reduction of US$1 MM on the well cost each year over the 3 year period of drilling.

GaffneyCline reviewed the Vendor's hook-up costs and optimisations. Table 112 provides a summary of the CAPEX for hook-up of new development wells.

Table 112: Hook-up Capital Costs

Hook-up Type	CAPEX (US$ MM)
Gas Production Well	1.21
Oil Production Well	0.41
Water Injection Well	0.20

3.3 Facilities and Infrastructure Projects CAPEX

The Consortium's cost program for facilities and infrastructure was reviewed by GaffneyCline against the expected development plan and production. Table 113 provides a summary of the expected CAPEX for projects to support the production and development plan for each of the concession areas.

Table 113: Summary of CAPEX by Concession Area for Future Development Projects

Concession Area	Project Description	CAPEX (US$ MM)
Obaiyed		
	LLP Compression Project	28.8
	Life Extension Project	12.0
NM		
	NM (Teen + Tamr) Development Project	63.7
BED 3		
	Sitra PWRI Project at BED3 (completion in 2020)	7.98
	BED3 LLP Compression Project (completion in 2020)	3.0
	BED3 Mercury Removal Project (completion in 2020)	4.53
	Oil Capacity Debottlenecking Project	5.0
	BED3 Electrification Project	15.0
BED 2		
	BED2 LLP Compression Project	9.3
AESW		
	Gas Debottlenecking Project	2.95
	AESW Electrification Project	10.9
	Al Barq Electrification (rental unit)	0.29/yr
	Bagha Electrification (rental unit)	0.29/yr
	Al Barq Facility Improvement Projects	4.5
	Bagha Facility Improvement Projects	6.2
NEAG		
	NEAG-1 Water Disposal Project (completion in 2020)	0.8
	NEAG-1 & NEAG-2 Water Disposal Projects	1.2
	NEAG-2 Electrification Project	1.5
	NEAG-JG Water Disposal Projects	5.3
	NEAG-JG Electrification	3.5

The following sections provide an outline of each project and expected completion dates.

3.4 Current Development Projects Status

GaffneyCline notes that there are a number of current projects being executed by the Vendor as part of the ongoing field development. Table 114 provides an overview of the status of these projects as advised by the Vendor and their expected completion dates. GaffneyCline has estimated for 2020 the expected expenditure for each of these projects, and included these in Table 114.

Table 114: Current Development Projects Status

Project	Status	Business Plan CAPEX (US$ MM)
Sitra PWRI Project at BED3	Construction ongoing – expected completion 09/2020	39.9
BED3 Mercury Removal Project	Vessel fabrication ongoing, tie-ins completed – expected completion 11/2020	15.1
BED3 / BED 2 LLP	Units purchased – expected delivery 9/2020 Installation planned only for BED 3 by 12/2020	18.6
BED / Sitra Electrification (3.5MW)	Completed installation 100%	-

3.5 Planned Future Development Projects

3.5.1 Obaiyed Concession Area Projects

Life Extension Projects – the current Obaiyed facility has a number of life extension projects to increase reliability and capacity (up to 450 MMscfd) on the existing Obaiyed plant. These include for items such as the upgrade of gas turbines, DCS systems, compressor controls, recycle compressor re-wheeling, and other minor repairs. The projects are planned for completion in 2024 with capital phased across 4 years.

LLP Compression Project – this project comprises of the installation of LLP compression (up to 54 MMscfd) at Train 1 of the Obaiyed facility to allow for the drawdown of lower pressure wells and includes the necessary pipeline and separation facilities at the Obaiyed facility. The project is planned to be completed by 2024, with capital expenditure phased across 4 years.

3.5.2 NM Concession Area Projects

NM (Teen + Tamr) Development Project – this project supports the development of the NM area, and the planned wells. The project includes for the infrastructure to transport the well fluids (via an 86 km pipeline) to the Obaiyed facility, where they will be separated with the gas compressed to allow it to be treated in the main Obaiyed plant. The compression is designed to operate in LLP (10 bar) and LP (29 bar) modes to support a reconfiguration parallel to series operation as wellhead pressures declines in future. The project is phased to allow for an initial 81 MMscfd (3 x 27 MMscfd) of compression to be installed by 2023 to support the production profile, with a final LLP compressor installed by 2025 to allow series operation of the units to draw down the wells.

3.5.3 BED 3 Projects

BED3 Oil Capacity Debottlenecking – this project allows the capacity of oil export to exceed 30 Mbpd at the BED3 facility by inclusion of separation, and an additional export pump. The project is expected to be complete by 2022, with capital phased over 2 years.

BED3 Electrification Project – this project targets the electrification of the ESP pumped wells in the BED 3 area. It targets a reduction in diesel consumption and improvement in ESP availability. It includes for installation of gas engines and the transmission system to support the existing 23 ESP pumped wells plus an additional margin for an extra 10 future ESP pumped wells. The project is phased over 4 years, and expected completion of all electrification in 2024.

3.5.4 BED 2 Projects

BED2 LLP Compression – this project supports the reduction in pressure in some of the BED2 wells and compresses up the gas back up to export pressure to ensure delivery at the BED3 facility. The compression is designed for 12.5 MMscfd. The project is expected to complete in 2021.

3.5.5 AESW Projects

AESW Gas Debottlenecking Project – this project supports the use of ullage in the Assil pipeline to transport Karan gas to the CO_2 Removal Plant for treatment. A crossover link between the Assil pipeline and Karan pipeline is included as well as an additional lease amine unit to treat gas in 2022/2023 to treat the gas that exceeds the CO_2 removal plant capacity. The project is expected to be complete by 2022 phased over 2 years.

AESW Electrification Project – this project targets the electrification of the ESP pumped wells in the AESW area. It targets a reduction in diesel consumption and improvement in ESP availability. It includes for installation of gas engines and the transmission system to support the existing 14 ESP pumped wells plus an additional margin for an extra 10 future ESP pumped wells. The project is phased over 4 years, with expected completion of all electrification in 2027.

Al Barq Facility Improvement Projects – these projects target improvement in the water handling and disposal capacity at the Al Barq facility, as well as increased capability and capacity to separate well fluids, and export oil. There are a total of 6 minor projects as part of the improvement plans, all of which are phased over the period from 2021 to 2024.

Bagha Facility Improvement Projects – these projects target improvement in the water handling and disposal capacity at the Bagha facility, as well as increased capability and capacity to separate the well fluids. There are a total of 4 minor projects as part of the improvement plans, all of which are phased over the period from 2021 to 2023.

3.5.6 NEAG Projects

NEAG-1 Water Disposal Project – this project is designed to provide an addition of 12 Mbpd water disposal at the NEAG-1 facility. The project has carried over from 2019, and a portion of the capital expenditure is included in 2020 for completion of the project.

NEAG-1 & NEAG-2 Water Disposal Project – this project provides an additional 13 Mbpd gross separation capacity and 15 Mbpd water disposal capacity at the NEAG-1 facilities and disposal of water into watered out wells at NEAG-2. This project is expected to compete in 2024, with the capital phased over 2 years.

NEAG-2 Electrification Project – this project provides additional gas engine power at the NEAG-2 facility as part of the overall field electrification project to reduce diesel and improve reliability. This project is expected to complete in 2022, with the capital phased over 2 years.

NEAG-JG Water Disposal Projects – these projects provide addition of 30 Mbpd water separation, handling and disposal via injection wells. The project is expected to complete in 2023 and is phased over 2 years.

NEAG-JG Electrification Project – this project provides 2.4 MW of power for the NEAG JG area to provide electrification to ESP wells. The capital is spread over a 5 year period as part of a DBOOT contract model, with the commencement of the contract in 2021 running to 2025. On completion, the power generation facilities will be transferred and form part of the concession assets.

3.6 Asset Integrity and HSSE CAPEX

Table 115 provides a summary of the asset integrity and HSSE CAPEX for the different asset areas.

The asset integrity costs are part of an ongoing program, and cover a number of activities at Obaiyed, BED 3 and NEAG to assure asset integrity of the facilities and infrastructure for future production years. Included in the program are the integrity management of the following main aspects:

- Pipelines;
- Plant static and rotating machinery;
- Electrical and instruments;
- Civils;
- Fire and gas;
- Firefighting; and
- Waste, accommodation and movables.

The HSSE costs cover the costs associated with well integrity restoration and ground contamination remediation, and cover a number of the concession areas as summarised in Table 115.

The asset integrity program is executed over a 6 year period starting in 2021 and the well integrity restoration and ground contamination program is executed over a 5 year period starting 2021.

Table 115: Summary of CAPEX by Concession Area for Asset Integrity and HSSE Projects

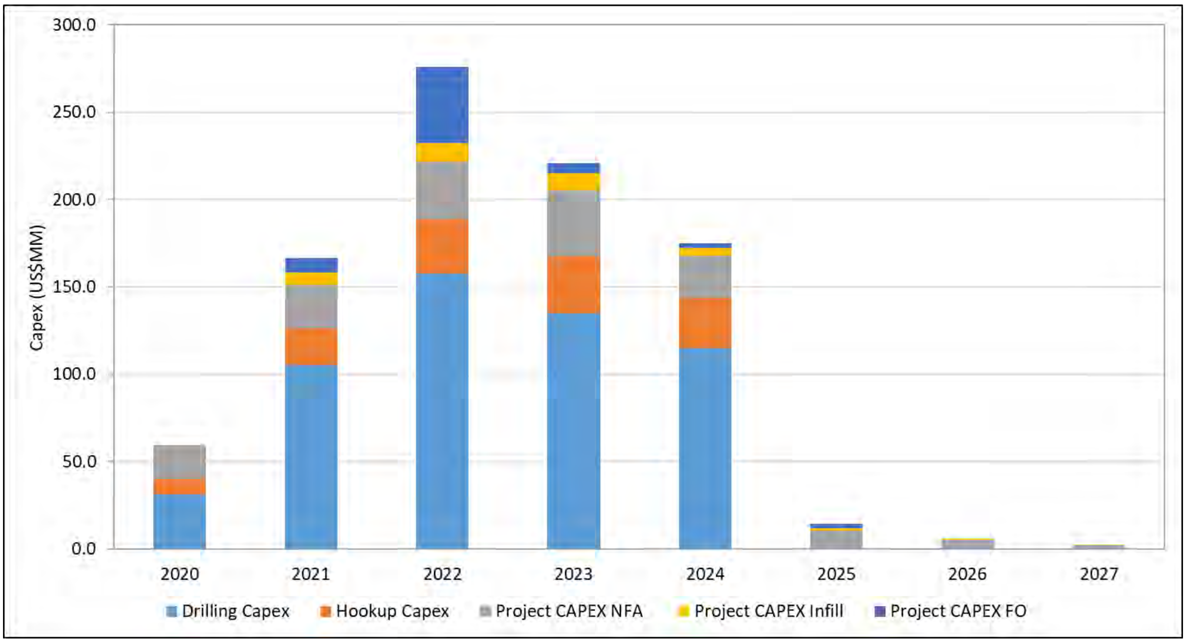
Concession Area	Description	CAPEX (US$ MM)
Obaiyed		
	Asset Integrity	13.2
	Well Integrity and Ground Remediation	1.0
BED 3		
	Asset Integrity	28.4
	Well Integrity and Ground Remediation	3.4
BED 2		
	Well Integrity and Ground Remediation	2.7
Sitra		
	Well Integrity and Ground Remediation	1.1
NEAG		
	Asset Integrity	3.9
NEAG Ext	Well Integrity and Ground Remediation	5.0
NEAG Tiba	Well Integrity and Ground Remediation	4.9
AESW		
	Well integrity and Ground Remediation	0.4

The annual CAPEX for all assets combined is provided in Table 116 and Figure 106. The annual CAPEX breakdown per asset is shown in Appendix III.

Table 116: Total Annual CAPEX All Assets

	2020	2021	2022	2023	2024	2025	2026	2027
Drilling Capex	31.3	105.4	157.8	134.7	114.8			
Hookup Capex	8.7	20.9	31.0	33.0	28.9			
Project CAPEX NFA	19.2	24.9	32.7	37.6	24.1	10.6	5.1	2.2
Project CAPEX Infill		6.8	10.7	9.8	4.6	1.2	0.9	0.6
Project CAPEX FO		8.8	43.8	5.8	2.7	2.7		
Total (US$ MM)	**59.3**	**166.8**	**276.1**	**221.0**	**175.1**	**14.5**	**6.0**	**2.8**

Figure 106: Total Annual CAPEX All Assets



3.7 OPEX

The OPEX forecasts have been developed based on an evaluation of the existing operating costs, taking into consideration the lower oil price environment and market conditions. The OPEX estimates for the fields were evaluated by GaffneyCline for the 5 years, 2021-2025, taking into consideration the planned activities/work programs of the development outlined by the Consortium.

Table 115 summarises the baseline OPEX for 2021 – 2025. After the 5 years, and in line with declining production, GaffneyCline considered the variable aspect of the operating costs to decline up to the end of concession.

The CAPEX and OPEX profiles, along with the Low, Best and High production profiles by asset are shown in Appendix II.

Included within the OPEX profiles are the additional well reactivation costs, as these are considered by GaffneyCline over and above the "business as usual" workover allowance in the baseline OPEX breakdown included in Table 117. Table 118 includes details of the additional OPEX included in the profiles, and the years they are realised.

Table 117: Five Year OPEX Breakdown

	Costs (US$ MM)				
	2021	**2022**	**2023**	**2024**	**2025**
Governance Costs – Consortia Group	3.5	3.0	2.5	2.5	2.5
Joint Venture Excess – Local Staff	3.5	3.5	3.5	3.5	3.5
Reclassed Overheads	16.5	16.5	16.5	16.5	16.5
Reclassed Workovers	9.0	9.0	9.0	9.0	9.0
Reclassed Petroleum Engineering Studies	0	0	0	1.0	1.0
Direct OPEX					
Aircraft	3.3	3.3	3.3	3.3	3.3
Catering & Cleaning Services	7.0	7.0	7.0	7.0	7.0
Diesel Fuel	12.0	6.0	2.2	2.2	2.2
Other (e.g. Wellhead, Maintenance and Contract Services)	45.4	43.4	46.4	46.4	43.4
Workovers	12.0	2.0	2.0	2.0	8.0
BAPETCO Overheads					
Aircraft Lease	2.0	2.0	2.0	2.0	2.0
Catering	1.8	1.8	1.8	1.8	1.8
Other (e.g. personnel salaries & wages)	50.6	50.6	50.6	50.6	50.6
Pipeline Tariffs	-17.6	-17.6	-17.6	-17.6	-17.6
Total OPEX (Note 1)	**149.0**	**130.5**	**129.2**	**130.2**	**133.2**

The baseline operating cost was developed with input from the Consortium to ensure it encompassed their organisation and company philosophies, and reflected a realistic level of savings considering market conditions and the current Vendor's operation. The original baseline developed, as shown in Table 118, did not fully reflect the ramp up of the North Matruh development from 2023-2025 when developed. Due to this, there will be minor variances in the operating costs for the profiles reflected in Appendix II.

Table 118: Well Reactivation OPEX

Year	Well Reactivation Concession Area	OPEX (US$ MM)
2021	Obaiyed	3.4
2022	Badr El Din 3	13.9
2022	Badr El Din 2	2.05
2021	Sitra	1.4
2021	AESW	11.4

4 Economic Assessment

GaffneyCline has conducted an economic analysis in order to assess the economic limit for production, the net Reserves entitlements due to Shell's interests and reference Net Present Values (NPVs) for each of the reserves cases. The economic limit is defined as the point in time when the Contractor's maximum cumulative net cash flow occurs for a project (after this time, the Contractor's forward-looking pre-tax operating cash flow is negative). The Entitlement volumes are made up of Cost Petroleum plus Profit Petroleum due to Shell under various Concession Agreements that govern the assets. It should be noted that the agreements governing the licenses are named Concession Agreements but in practice function similarly to global Petroleum Sharing Contracts (PSCs) and may be referred to as PSCs throughout this report.

These assessments have been based upon GaffneyCline's understanding of the fiscal and contractual terms governing these assets, and the various economic and commercial assumptions described herein.

4.1 Price Assumptions

For the economic limit, NPV and entitlement calculations, GaffneyCline's own 1Q 2020 Brent Crude oil price scenario has been used as the reference oil price. This scenario is shown in Table 119.

Table 119: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2020	63.38
2021	64.50
2022	67.25
2023	70.00
2024+	+2% per annum

The oil prices realised or expected from the sale of crude produced from the various license areas is based on information provided by the Vendor and the Consortium and are summarized in Table 120.

Table 120: Crude Differentials to Brent

Crude	Differential (US$/Bbl)
NEAG Tiba & NEAG Ext	-1.85
Western Desert Discount (All other licenses)	-2.20

For the cash flow calculations, all costs have been inflated at 2% per annum from 2021 onwards.

The gas price assumed is based on various Gas Sales Agreements executed with the Egyptian General Petroleum Corporation (EGPC) and information from the Vendor. The gas price and energy content of natural gas assumed for each asset are summarized in Table 121.

Table 121: Natural Gas Price and Energy Content

Concession	Gas Price (US$/MMBtu)	Energy Content (MMBtu/Mscf)
Obaiyed	2.65	1.118
NUMB	2.65	1.160
NM	2.65	1.150
BED 2	2.65	1.087
BED 3	2.50	1.087
Sitra	2.50	1.085
NAES	2.65	1.085
NEAG Tiba	2.50	1.085
NEAG Ext	2.50	1.085
AESW	2.65	1.085

In compliance with instructions and the accepted definitions for Reserves, we have evaluated the Reserves within this report as of the Effective Date, 31st December 2019, using a reasonable oil and gas price outlook as of that date. We would note that since the Effective Date, various events have result in a material downward movement in the oil price. If the oil price remains significantly below the scenario used here and the long-term price expectation is revised downward, there may be a material revision to the volumes classified as Reserves and the NPVs stated herein. In light of such volatility and at the request of the client, a sensitivity analysis assuming a US$10/Bbl decrease to the oil price is included in Section 4.3 below.

4.2 Fiscal Assumptions

The fiscal terms applied to the various cases are based on the Concession Contracts governing the areas. The key elements of the various applicable fiscal terms are summarized in Table 122.

Table 122: Fiscal Terms

Concession	Obaiyed	NUMB	NM	BED 2	BED 3	Sitra	NAES	NEAG Tiba	NEAG Ext.	AESW
Shell Working Interest	100%	100%	100%	100%	100%	100%	100%	52%	52%	40%
Assumed License End[1]	2029	2043	2045	2034	2026	2025	2042	2034	2036	2033
Cost Recovery Cap	30%	30%	25%	35%	35%	35%	30%	40%	40%	30%
Capex Amortization Period (Years)	5	5	5	5	5	5	5	5	5	5
Contractor Excess Cost Recovery Share	Same as Profit Share	10%	0%	Same as Profit Share	Same as Profit Share	Same as Profit Share	0%	Same as Profit Share	Same as Profit Share	0%
Contractor Liquids Profit Share[2]	20%-12.5%	23%-10.5%	20%-17.5%	17%	17%	17%	20%-17.5%	23%-14%	23%-14%	17%-15%
Contractor Gas Profit Share[2]	20%	23%-19%	20%-18%	17%	17%	17%	20%-18%	25%	25%	17%-15%
Income Tax	Borne by EGPC on behalf of the Contractor									
Historic Costs Recoverable (US$MM)[3]	86.0	18.6	19.6	27.1	147.9	122.3	39.6	19.3	52.3	359.0

Notes:

1. This is a somewhat simplified assumption as some fields within the concession have varying license ends and some 5 or 10 year extensions are included for concessions that include such a provision for extension at the election of the Contractor.
2. The profit share shown is the full possible range in the relevant contract, where it is defined in tranches based primarily on daily production and in a couple of instances also on liquids price. In most of the Reserves cases, the average applicable Contractor share is close to the higher end of the range shown.
3. This amount is based on information provided by the Vendor and the Consortium and is the sum total of cost recovery due and carried at the end of 2019 as well as the amortization yet to be recoverable from CAPEX incurred before the end of 2019.

For the economic analysis, all operating costs are assumed to be recoverable except a US$1.0/Bbl terminal fee, which is considered non-recoverable. Historically, a portion of Shell operating costs was non-recoverable, primarily associated with G&A. However, it is understood that the extent to which forward-looking operating costs will be recoverable will be based on discussions between the new owner and EGPC, GaffneyCline has not included any assumption on the level of potential non-recoverable operating costs in this report.

4.3 Results

The economic limit for production for each Reserves case is shown in Table 123.

The resulting Reserves, both gross (100%) and net to Shell's interest, are shown in Table 2 in the Executive Summary. The corresponding NPVs at a discount rate of 10%, net to Shell's interest, are shown in Table 4.

Table 123: Economic Limits

Assets	Economic Limit (End of Year)		
	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	2029	2029	2029
NUMB	2023	2023	2023
NM	2029	2029	2029
BED 2	2021	2027	2031
BED 3	2025	2025	2025
Sitra	2023	2025	2025
NAES	2020	2028	2028
NEAG Tiba	2026	2026	2027
NEAG Ext	2025	2027	2030
AESW	2028	2031	2032

4.4 Sensitivity Analysis

As mentioned above, GaffneyCline reran the economic analyses using a Brent Crude oil price scenario US$10/Bbl lower than that shown in Table 119. As in the base case oil price scenario, costs were escalated at 2.0% p.a. from 2021, with no adjustment for the higher or lower oil price. The differentials to Brent for each asset and the assumed gas prices were left unchanged.

The economic limit was found to fall one year earlier than it did in the base case in a few cases, but most were unchanged, and the only significant change was for the Sitra Proved Reserves case, where it fell at end 2020 instead of end 2023. Resulting Reserves under this lower oil price scenario are shown in Table 124, and the corresponding NPV10s in Table 125.

Table 124: Summary of Reserves as at 31st December 2019 under a US$10/Bbl Lower Oil Price Scenario

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	17.1	22.2	26.8	100.0	6.6	7.9	8.9	50.0	3.3	3.9	4.4
NUMB	0.2	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.1	0.1	0.1
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.6
BED 2	2.9	5.8	8.2	100.0	1.3	2.5	3.3	50.0	0.6	1.3	1.6
BED 3	10.7	15.3	20.5	100.0	4.9	6.9	8.3	50.0	2.5	3.5	4.1
Sitra	1.8	11.9	17.3	100.0	0.8	5.5	7.3	50.0	0.4	2.7	3.6
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	6.0	8.9	12.7	52.0	1.6	2.0	2.5	26.0	0.8	1.0	1.2
NEAG Ext.	8.1	12.2	17.5	52.0	2.3	3.1	4.2	26.0	1.1	1.6	2.1
AESW	16.9	29.6	45.1	40.0	2.8	4.8	6.0	20.0	1.4	2.4	3.0
Total	**68.8**	**116.1**	**168.1**		**22.4**	**36.4**	**45.7**		**11.2**	**18.2**	**22.9**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% of Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	367.1	425.7	483.0	100.0	142.6	152.9	162.7	50.0	71.3	76.5	81.4
NUMB	14.5	15.0	15.5	100.0	6.7	6.9	7.1	50.0	3.4	3.5	3.6
M	46.4	76.8	128.0	100.0	18.5	27.1	34.3	50.0	9.3	13.6	17.1
BED 2	9.3	38.7	72.4	100.0	4.0	17.2	29.6	50.0	2.0	8.6	14.8
BED 3	47.1	60.8	75.0	100.0	21.7	27.7	30.5	50.0	10.9	13.9	15.2
Sitra	9.1	32.1	42.3	100.0	4.2	14.8	18.1	50.0	2.1	7.4	9.1
NAES	1.1	24.6	36.7	100.0	0.5	10.8	16.1	50.0	0.2	5.4	8.1
NEAG Tiba	16.7	23.1	32.2	52.0	4.4	5.3	6.6	26.0	2.2	2.7	3.3
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	473.3	603.4	785.8	40.0	77.6	97.3	105.2	20.0	38.8	48.7	52.6
Total	**984.7**	**1,300.3**	**1,670.9**		**280.2**	**360.1**	**410.2**		**140.1**	**180.0**	**205.1**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 125: Summary of Post-Tax NPV10 of Future Cash Flow from Reserves, as at 31st December 2019, under a US$10/Bbl Lower Oil Price Scenario

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	263.0	319.6	373.3	131.5	159.8	186.7
NUMB	17.9	18.6	19.2	8.9	9.3	9.6
NM	-5.0	59.2	120.5	-2.5	29.6	60.3
BED 2	25.8	48.2	70.3	12.9	24.1	35.2
BED 3	60.9	154.2	211.2	30.4	77.1	105.6
Sitra	10.6	96.0	171.8	5.3	48.0	85.9
NAES	0.7	4.4	11.5	0.3	2.2	5.7
NEAG Tiba	17.3	33.0	51.0	8.7	16.5	25.5
NEAG Ext	30.0	47.5	70.9	15.0	23.8	35.4
AESW	98.0	190.3	227.9	49.0	95.2	113.9
Total	**519.1**	**970.9**	**1,327.6**	**259.6**	**485.4**	**663.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs herein do not represent GaffneyCline's opinion of the market value of the asset or any interest therein.

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 Shell, Cairn, the Consortium, and/or obtained from other sources (e.g., public domain), the 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 Shell, Cairn, the Consortium and/or obtained from other sources (e.g., public domain), and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

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

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

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

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

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMBbl). 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.

Definition of Reserves and Resources

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

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

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

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

Reserves net to Shell's interest are quoted as Net Entitlement Reserves, reflecting the terms of the applicable contracts. Contingent Resources are presented at a gross field level and Shell working interest level.

GaffneyCline has not undertaken a site visit and inspection. 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. However, 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 licences and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Use of Net Present Values

It should be clearly understood that the NPVs contained herein do not represent a GaffneyCline opinion as to the market value of the subject property, nor any interest in it.

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 Proved and/or Probable and/or Possible Reserves may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; 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 NPVs presented herein.

Qualifications

GaffneyCline is an independent international energy advisory group of more than 55 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

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 the Consortium. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

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

The team was led by Dr. Rand A. Mustafa, North Africa Advisor, who has over 12 years' industry experience. She holds a Ph.D. and Bachelors in Petroleum Engineering. She is a member of the Society of Petroleum Engineers.

The report was reviewed by Dr. John Barker, Technical Director, Reservoir Engineering, who has 35 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

Yours sincerely,

Gaffney, Cline & Associates Limited

Project Manager
Dr. Rand A. Mustafa, North Africa Advisor

Reviewed by
Dr. John Barker, Technical Director

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
HIIP	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)

Gaffney Cline

Appendix II
Gross Field Production and Cost Profiles

Table AII.1: Obaiyed

	Low					Best					High					
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	CAPEX
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.3	129.1	5.3	129.1	38.8	5.5	130.6	5.5	130.6	38.8	5.6	131.9	5.6	131.9	38.9	0.0
2021	4.1	108.1	8.6	158.5	33.5	4.4	111.9	12.0	174.4	34.8	4.5	115.3	15.0	189.7	35.9	25.0
2022	3.6	91.6	5.7	123.7	25.7	3.9	97.0	7.4	142.0	26.3	4.1	101.9	9.0	159.7	26.9	31.6
2023	3.1	77.9	5.7	118.6	25.5	3.4	84.4	7.6	139.5	26.2	3.7	90.3	9.4	158.9	26.8	43.5
2024	2.7	67.1	6.1	124.7	23.5	3.1	74.3	8.3	149.6	24.3	3.3	80.9	10.2	172.7	25.0	42.3
2025	2.3	58.1	4.3	98.7	23.3	2.7	65.8	5.4	118.3	23.8	3.0	72.9	6.5	137.9	24.2	1.9
2026	2.0	50.6	3.5	83.3	19.7	2.4	58.5	4.5	101.1	22.9	2.7	66.0	5.4	119.0	23.2	0.7
2027	1.7	44.3	3.0	71.3	19.1	2.2	52.2	3.9	87.9	22.2	2.5	59.9	4.8	104.6	22.5	0.0
2028	1.5	38.8	2.6	61.2	18.5	2.0	46.7	3.4	76.6	21.6	2.3	54.6	4.2	92.4	21.9	0.0
2029	1.3	23.2	2.0	35.9	17.5	1.8	28.4	2.6	45.7	20.3	2.1	33.6	3.2	55.5	20.6	0.0
Total to 2029	**10.1**	**251.7**	**17.1**	**367.1**	**245.0**	**11.4**	**273.9**	**22.2**	**425.7**	**261.1**	**12.3**	**294.9**	**26.8**	**483.0**	**265.9**	**144.9**
Total to economic limit	**10.1**	**251.7**	**17.1**	**367.1**	**245.0**	**11.4**	**273.9**	**22.2**	**425.7**	**261.1**	**12.3**	**294.9**	**26.8**	**483.0**	**265.9**	

Table AII.2: NM

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.5
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.8
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43.8
2023	3.5	33.1	0	0	3.1	5.7	46	0	0	4.7	8.8	60.7	0	0	6.7	36.6
2024	5.3	50	0	0	4.7	9.3	74	0	0	7.6	15.4	104.6	0	0	11.6	46.1
2025	2.7	24.5	0	0	2.3	5.6	43	0	0	4.5	11.1	72.4	0	0	8.2	2.7
2026	1.3	11	0	0	1.1	3.2	23.4	0	0	2.5	7.6	47.3	0	0	5.5	0
2027	0.6	5	0	0	0.5	1.8	12.8	0	0	1.4	5.2	31.2	0	0	3.7	0
2028	0.3	2.3	0	0	0.2	1.1	7	0	0	0.8	3.6	20.6	0	0	2.5	0
2029	0.1	1.1	0	0	0.2	0.6	3.9	0	0	0.4	2.5	13.8	0	0	1.7	0
2030	0.1	0.5	0	0	0.2	0.3	2.2	0	0	0.3	1.7	9.2	0	0	1.1	0
2031	0	0.2	0	0	0.1	0.2	1.2	0	0	0.2	1.2	6.2	0	0	0.8	0
2032	0	0.1	0	0	0.1	0.1	0.7	0	0	0.2	0.8	4.2	0	0	0.5	0
2033	0	0.1	0	0	0.1	0.1	0.4	0	0	0.1	0.6	2.9	0	0	0.4	0
2034	0	0	0	0	0.1	0	0.2	0	0	0.1	0.4	1.9	0	0	0.3	0
2035	0	0	0	0	0.1	0	0.1	0	0	0.1	0.3	1.3	0	0	0.2	0
2036	0	0	0	0	0.1	0	0.1	0	0	0.1	0.2	0.9	0	0	0.1	0
2037	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.6	0	0	0.1	0
2038	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.4	0	0	0.1	0
2039	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.3	0	0	0.1	0
2040	0	0	0	0	0.1	0	0	0	0	0.1	0	0.2	0	0	0.1	0
2041	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2042	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2043	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2044	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
2045	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
2046	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
Total to 2046	**5**	**46.7**	**0**	**0**	**14.5**	**10.3**	**78.6**	**0**	**0**	**24.3**	**21.8**	**138.5**	**0**	**0**	**44.1**	**139.4**
Total to economic limit	**5**	**46.4**	**0**	**0**	**12.2**	**10**	**76.8**	**0**	**0**	**21.9**	**19.8**	**128**	**0**	**0**	**39.7**	

Table AII.3: NUMB

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0.2	14.9	0.2	14.9	2.2	0.3	15.1	0.3	15.1	2.2	0.3	15.2	0.3	15.2	2.2	0.0
2021	0.2	11.0	0.2	11.0	1.2	0.2	11.3	0.2	11.3	1.2	0.2	11.6	0.2	11.6	1.2	0.0
2022	0.1	8.1	0.1	8.1	1.0	0.1	8.5	0.1	8.5	1.0	0.1	8.8	0.1	8.8	1.0	0.0
2023	0.1	5.9	0.1	5.9	1.0	0.1	6.3	0.1	6.3	1.0	0.1	6.7	0.1	6.7	1.0	0.0
2024	0.1	4.3	0.1	13.4	3.2	0.1	4.8	0.1	17.3	3.2	0.1	5.1	0.1	24.0	3.2	38.0
2025	0.1	3.2	0.1	10.5	3.2	0.1	3.6	0.1	14.4	3.2	0.1	3.9	0.1	20.6	3.2	0.0
2026	0.0	2.3	0.0	8.2	2.6	0.0	2.7	0.0	12.0	3.1	0.1	3.0	0.1	17.6	3.2	0.0
2027	0.0	1.7	0.0	6.4	2.5	0.0	2.0	0.0	10.1	3.1	0.0	2.3	0.0	15.2	3.1	0.0
2028	0.0	1.3	0.0	5.0	2.5	0.0	1.5	0.0	8.5	3.0	0.0	1.7	0.0	13.1	3.0	0.0
2029	0.0	0.9	0.0	4.0	2.4	0.0	1.1	0.0	7.2	2.9	0.0	1.3	0.0	11.3	3.0	0.0
2030	0.0	0.7	0.0	3.1	2.3	0.0	0.9	0.0	6.1	2.8	0.0	1.0	0.0	9.8	2.9	0.0
2031	0.0	0.5	0.0	2.5	2.3	0.0	0.6	0.0	5.1	2.8	0.0	0.8	0.0	8.5	2.8	0.0
2032	0.0	0.2	0.0	1.7	2.2	0.0	0.5	0.0	4.4	2.7	0.0	0.6	0.0	7.4	2.8	0.0
2033	0.0	0.0	0.0	1.3	2.1	0.0	0.1	0.0	3.5	2.6	0.0	0.4	0.0	6.4	2.7	0.0
2034	0.0	0.0	0.0	1.0	2.1	0.0	0.0	0.0	2.9	2.6	0.0	0.1	0.0	5.3	2.7	0.0
2035	0.0	0.0	0.0	0.8	2.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0	0.0	4.6	2.6	0.0
2036	0.0	0.0	0.0	0.7	2.0	0.0	0.0	0.0	2.2	2.5	0.0	0.0	0.0	4.1	2.6	0.0
2037	0.0	0.0	0.0	0.5	1.9	0.0	0.0	0.0	1.9	2.4	0.0	0.0	0.0	3.6	2.5	0.0
2038	0.0	0.0	0.0	0.4	1.9	0.0	0.0	0.0	1.6	2.4	0.0	0.0	0.0	3.2	2.5	0.0
2039	0.0	0.0	0.0	0.3	1.9	0.0	0.0	0.0	1.4	2.3	0.0	0.0	0.0	2.8	2.4	0.0
2040	0.0	0.0	0.0	0.3	1.8	0.0	0.0	0.0	1.2	2.3	0.0	0.0	0.0	2.4	2.4	0.0
2041	0.0	0.0	0.0	0.2	1.8	0.0	0.0	0.0	1.0	2.3	0.0	0.0	0.0	2.2	2.4	0.0
2042	0.0	0.0	0.0	0.2	1.8	0.0	0.0	0.0	0.9	2.2	0.0	0.0	0.0	1.9	2.3	0.0
2043	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.3	2.0	0.0	0.0	0.0	0.6	2.1	0.0
Total to 2043	**0.3**	**20.1**	**0.3**	**36.7**	**49.6**	**0.4**	**21.5**	**0.4**	**53.2**	**58.5**	**0.4**	**22.9**	**0.4**	**75.6**	**59.8**	**38.0**
Total to economic limit	**0.2**	**14.5**	**0.2**	**14.5**	**5.5**	**0.2**	**15.1**	**0.2**	**15.0**	**5.5**	**0.2**	**15.2**	**0.2**	**15.5**	**5.5**	

Gaffney Cline

Table AII.4: BED 2

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	CAPEX
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	1.0	14.3	5.4	14.3	16.7	1.0	14.7	5.6	14.7	16.8	1.1	15.0	5.9	15.0	16.9	12.0
2021	0.6	11.2	2.7	11.2	13.3	0.6	12.2	3.1	12.2	13.4	0.7	13.0	3.5	13.0	13.6	7.1
2022	0.4	8.8	1.7	9.9	13.4	0.5	10.2	2.4	14.1	13.7	0.5	11.2	3.0	17.1	13.9	8.7
2023	0.2	6.8	1.1	10.1	11.1	0.3	8.5	1.8	20.9	11.3	0.4	9.7	2.5	28.3	11.6	6.8
2024	0.2	5.4	0.7	7.6	9.8	0.2	7.1	1.3	17.4	10.1	0.3	8.4	1.9	25.0	10.3	0.2
2025	0.1	4.2	0.4	5.8	10.0	0.2	5.9	0.9	14.5	10.1	0.2	7.2	1.5	22.0	10.3	0.2
2026	0.1	3.3	0.3	4.4	9.4	0.1	4.9	0.7	12.1	9.7	0.2	6.3	1.2	19.5	9.9	0.0
2027	0.0	2.6	0.2	3.3	8.9	0.1	4.1	0.5	10.2	9.3	0.1	5.4	0.9	17.3	9.6	0.0
2028	0.0	2.0	0.1	2.6	8.5	0.1	3.4	0.4	8.5	8.9	0.1	4.7	0.8	15.4	9.3	0.0
2029	0.0	1.6	0.1	2.0	8.1	0.0	2.8	0.3	7.2	8.6	0.1	4.1	0.6	13.7	9.0	0.0
2030	0.0	1.2	0.1	1.5	7.8	0.0	2.4	0.3	6.0	8.3	0.1	3.5	0.5	12.2	8.8	0.0
2031	0.0	1.0	0.0	1.2	7.4	0.0	2.0	0.2	5.1	8.1	0.0	3.0	0.4	10.8	8.6	0.0
2032	0.0	0.8	0.0	0.9	7.1	0.0	1.7	0.2	4.3	7.8	0.0	2.6	0.4	9.7	8.4	0.0
2033	0.0	0.6	0.0	0.7	6.9	0.0	1.4	0.1	3.7	7.6	0.0	2.3	0.3	8.7	8.2	0.0
2034	0.0	0.1	0.0	0.1	6.1	0.0	0.4	0.0	1.0	6.7	0.0	0.7	0.1	2.6	7.2	0.0
Total to 2034	**0.9**	**23.3**	**4.6**	**27.6**	**144.5**	**1.1**	**29.8**	**6.5**	**55.5**	**150.6**	**1.4**	**35.4**	**8.6**	**84.0**	**155.5**	**35.0**
Total to economic limit	**0.5**	**9.3**	**2.9**	**9.3**	**30.0**	**1.0**	**24.7**	**6.0**	**42.4**	**94.4**	**1.4**	**33.4**	**8.3**	**76.4**	**131.8**	

Table AII.5: BED 3

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.7	28.0	8.1	28.6	31.1	6.4	29.2	9.2	30.8	31.5	6.7	30.0	9.9	32.2	31.8	20.9
2021	3.1	19.5	7.9	22.1	22.5	3.6	21.5	11.7	28.7	23.9	3.9	22.9	15.6	35.2	25.4	39.6
2022	2.0	13.7	4.8	24.8	32.9	2.4	15.9	7.7	33.9	33.9	2.7	17.6	11.1	43.4	35.2	18.1
2023	1.4	9.6	3.9	23.7	18.5	1.7	11.8	6.0	31.4	19.2	1.9	13.5	8.6	39.7	20.2	12.9
2024	0.9	6.8	2.7	17.3	17.8	1.2	8.8	4.2	23.7	18.4	1.3	10.4	6.3	30.8	19.1	9.4
2025	0.6	4.8	1.9	12.7	17.9	0.8	6.5	3.1	18.0	18.4	1.0	8.1	4.8	24.0	19.0	3.9
2026	0.1	1.1	0.4	3.1	10.9	0.2	1.6	0.8	4.6	15.3	0.2	2.1	1.5	6.5	17.7	1.5
Total to 2026	**5.1**	**30.5**	**10.9**	**48.3**	**151.7**	**5.9**	**34.8**	**15.6**	**62.5**	**160.7**	**6.4**	**38.2**	**21.1**	**77.4**	**168.3**	**106.2**
Total to economic limit	**5.1**	**30.1**	**10.7**	**47.1**	**140.8**	**5.8**	**34.2**	**15.3**	**60.8**	**145.4**	**6.4**	**37.5**	**20.5**	**75.0**	**150.6**	

Table AII.6: Sitra

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	4.5	23.4	4.9	24.9		4.8	24.4	5.5	27.5	35.2	4.9	25.2	5.8	29.9	35.3	7.3
2021	2.5	14.2	5.4	16.3	35.0	2.9	16.3	8.2	21.3	25.8	3.2	17.9	10.6	26.4	26.7	39.4
2022	1.6	8.8	4.4	10.6	24.8	2.1	11.0	7.7	15.7	21.5	2.4	12.9	11.3	21.9	22.8	21.2
2023	1.0	5.4	2.5	6.8	20.3	1.4	7.4	5.2	11.2	19.7	1.8	9.2	8.5	16.9	20.9	0.3
2024	0.6	3.3	1.4	4.1	18.7	1.0	5.0	3.6	7.5	18.9	1.4	6.6	6.4	12.3	19.9	0.3
2025	0.4	1.9	0.8	2.2	18.1	0.7	3.1	2.4	4.7	20.2	0.9	4.4	4.7	8.5	21.0	0.0
Total to 2030	**3.9**	**20.8**	**7.1**	**23.7**	19.6	**4.7**	**24.5**	**11.9**	**32.1**	**141.3**	**5.4**	**27.8**	**17.3**	**42.3**	**146.6**	**68.6**
Total to economic limit	**3.5**	**18.9**	**6.3**	**21.4**	**136.4**	**4.7**	**24.5**	**11.9**	**32.1**	**141.3**	**5.4**	**27.8**	**17.3**	**42.3**	**146.6**	

Table AII.7: AESW

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	2.2	120.8	5.0	151.1	54.4	2.4	122.3	6.0	153.0	54.8	2.4	123.4	6.8	154.6	55.1	17.4
2021	1.1	89.0	6.0	190.7	49.4	1.3	92.6	8.1	202.8	50.2	1.4	95.4	9.9	220.1	50.8	52.5
2022	0.7	65.6	9.8	248.0	34.9	0.8	70.4	13.8	277.5	36.4	0.9	74.2	17.3	319.2	37.7	83.6
2023	0.4	48.1	8.5	220.4	34.2	0.5	53.5	14.1	260.8	36.2	0.6	57.8	19.5	313.8	38.2	67.7
2024	0.2	35.5	6.4	168.6	32.6	0.3	41.0	11.5	208.8	34.5	0.4	45.4	16.9	260.6	36.5	20.2
2025	0.1	26.2	4.3	121.3	32.6	0.2	31.5	8.5	159.1	34.1	0.3	36.0	13.4	207.1	35.9	3.8
2026	0.1	19.3	2.9	87.4	30.5	0.1	24.3	6.3	121.9	32.0	0.2	28.6	10.4	165.7	33.7	3.8
2027	0.0	14.2	2.0	63.0	28.8	0.1	18.8	4.7	94.1	30.3	0.1	22.9	8.1	133.5	31.9	2.8
2028	0.0	10.2	1.4	45.3	27.3	0.1	14.5	3.5	72.9	28.8	0.1	18.4	6.4	108.2	30.3	0.6
2029	0.0	7.5	1.0	32.8	26.0	0.0	11.0	2.6	56.6	27.4	0.1	14.6	5.1	88.1	29.0	0.6
2030	0.0	5.6	0.7	23.7	24.8	0.0	8.6	2.0	44.4	26.3	0.0	11.7	4.1	72.0	27.8	0.6
2031	0.0	4.1	0.5	17.2	23.8	0.0	6.8	1.5	35.0	25.3	0.0	9.5	3.3	59.4	26.8	0.6
2032	0.0	3.1	0.3	12.5	22.8	0.0	5.3	1.0	27.8	24.1	0.0	7.8	2.2	49.1	25.4	0.6
2033	0.0	0.8	0.1	3.0	20.4	0.0	1.4	0.2	7.5	21.4	0.0	2.1	0.5	13.6	22.1	0.0
Total to 2033	**1.8**	**164.4**	**17.9**	**505.9**	**442.6**	**2.1**	**183.4**	**30.6**	**629.1**	**461.8**	**2.4**	**200.1**	**45.3**	**790.8**	**481.2**	**254.8**
Total to economic limit	**1.8**	**156.7**	**16.9**	**473.3**	**324.9**	**2.1**	**180.9**	**30.2**	**616.2**	**416.3**	**2.4**	**199.3**	**45.1**	**785.8**	**459.1**	

Table AII.8: NAES

	Low					Best					High					
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	CAPEX
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0.0	3.1	0.0	3.1	0.8	0.0	3.8	0.0	3.8	0.8	0.0	3.8	0.0	3.8	0.8	0.0
2021	0.0	1.0	0.0	1.0	0.8	0.0	1.8	0.0	1.8	0.8	0.0	2.2	0.0	2.2	0.8	0.0
2022	0.0	0.3	0.0	0.3	0.7	0.0	0.9	0.0	0.9	0.7	0.0	1.3	0.0	1.3	0.7	0.0
2023	0.0	0.1	0.0	0.1	0.7	0.0	0.4	0.0	0.4	0.7	0.0	0.7	0.0	0.7	0.7	0.0
2024	0.0	0.0	0.0	21.2	1.3	0.0	0.2	0.0	30.3	1.8	0.0	0.4	0.1	39.1	2.3	14.4
2025	0.0	0.0	0.0	8.2	0.5	0.0	0.1	0.0	16.5	1.0	0.0	0.2	0.0	25.3	1.5	0.0
2026	0.0	0.0	0.0	2.7	0.4	0.0	0.0	0.0	7.9	0.9	0.0	0.1	0.0	14.6	1.6	0.0
2027	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	3.8	0.8	0.0	0.1	0.0	8.5	1.7	0.0
2028	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	1.8	0.7	0.0	0.0	0.0	4.9	1.8	0.0
2029	0.0	0.0	0.0	0.1	0.3	0.0	0.0	0.0	0.9	0.6	0.0	0.0	0.0	2.8	1.7	0.0
2030	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.4	0.6	0.0	0.0	0.0	1.6	1.5	0.0
2031	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.5	0.0	0.0	0.0	0.9	1.4	0.0
2032	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.5	1.2	0.0
2033	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.3	1.1	0.0
2034	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.9	0.0
2035	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.1	0.8	0.0
2036	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.1	0.8	0.0
2037	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.7	0.0
2038	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.6	0.0
2039	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.5	0.0
2040	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.5	0.0
2041	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.5	0.0
2042	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0
Total to 2042	**0.0**	**1.7**	**0.0**	**13.9**	**8.8**	**0.0**	**2.7**	**0.0**	**25.3**	**13.2**	**0.0**	**3.3**	**0.1**	**39.1**	**24.4**	**14.4**
Total to economic limit	**0.0**	**1.1**	**0.0**	**1.1**	**0.8**	**0.0**	**2.7**	**0.0**	**24.6**	**8.0**	**0.0**	**3.3**	**0.1**	**36.7**	**11.8**	

Table AII.9: NEAG EXT

	Low					Best					High					
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		CAPEX
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.9	0.0	5.9	0.0	31.4	6.2	0.0	6.2	0.0	31.5	6.4	0.0	6.4	0.0	31.6	0.8
2021	3.7	0.0	3.7	0.0	23.1	4.2	0.0	4.2	0.0	23.3	4.5	0.0	4.5	0.0	23.4	1.7
2022	2.4	0.0	6.2	0.0	21.3	2.9	0.0	8.9	0.0	22.3	3.3	0.0	12.2	0.0	23.5	33.9
2023	2.6	0.0	3.9	0.0	20.3	3.0	0.0	5.5	0.0	20.9	3.3	0.0	7.8	0.0	21.7	9.1
2024	1.9	0.0	2.6	0.0	21.8	2.3	0.0	3.7	0.0	22.2	2.6	0.0	5.3	0.0	22.8	1.8
2025	1.4	0.0	1.9	0.0	22.1	1.7	0.0	2.8	0.0	22.4	2.1	0.0	4.0	0.0	22.8	0.7
2026	1.0	0.0	1.4	0.0	20.9	1.3	0.0	2.2	0.0	21.3	1.6	0.0	3.1	0.0	21.7	0.0
2027	0.8	0.0	1.1	0.0	19.9	1.1	0.0	1.7	0.0	20.4	1.3	0.0	2.5	0.0	20.8	0.0
2028	0.6	0.0	0.8	0.0	19.0	0.8	0.0	1.4	0.0	19.7	1.1	0.0	2.1	0.0	20.0	0.0
2029	0.4	0.0	0.6	0.0	18.2	0.6	0.0	1.2	0.0	19.0	0.9	0.0	1.8	0.0	19.4	0.0
2030	0.3	0.0	0.5	0.0	17.5	0.5	0.0	1.0	0.0	18.4	0.7	0.0	1.5	0.0	18.8	0.0
2031	0.3	0.0	0.4	0.0	16.8	0.4	0.0	0.8	0.0	17.8	0.6	0.0	1.3	0.0	18.3	0.0
2032	0.2	0.0	0.3	0.0	16.1	0.3	0.0	0.6	0.0	17.1	0.5	0.0	1.0	0.0	17.6	0.0
2033	0.0	0.0	0.0	0.0	13.4	0.0	0.0	0.0	0.0	14.3	0.1	0.0	0.1	0.0	14.7	0.0
2034	0.0	0.0	0.0	0.0	11.6	0.0	0.0	0.0	0.0	12.9	0.0	0.0	0.0	0.0	13.2	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.6	0.0
Total to 2036	**7.9**	**0.0**	**10.7**	**0.0**	**293.6**	**9.3**	**0.0**	**14.7**	**0.0**	**303.4**	**10.6**	**0.0**	**19.6**	**0.0**	**333.8**	**47.9**
Total to economic limit	**6.6**	**0.0**	**8.8**	**0.0**	**140.4**	**8.3**	**0.0**	**12.8**	**0.0**	**184.3**	**10.2**	**0.0**	**18.7**	**0.0**	**246.4**	

Table AII.10: NEAG TIBA

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	2.0	12.0	2.4	12.4	9.8	2.0	12.3	2.7	13.1	9.9	2.0	12.6	2.9	13.7	10.0	8.2
2021	1.3	8.0	2.8	9.7	10.2	1.4	8.8	4.0	12.2	10.6	1.4	9.3	5.2	15.1	11.0	17.2
2022	1.0	5.4	1.9	6.4	8.7	1.1	6.3	2.8	8.6	9.0	1.2	7.0	3.9	11.3	9.4	4.1
2023	0.7	3.6	2.6	5.4	8.9	0.8	4.5	3.8	8.2	9.3	0.9	5.3	5.4	11.7	9.9	19.7
2024	0.5	2.4	3.1	5.4	8.9	0.6	3.3	4.7	9.2	9.5	0.7	4.0	6.7	14.3	10.3	26.1
2025	0.4	1.6	2.2	3.7	8.8	0.5	2.4	3.6	6.9	9.3	0.6	3.1	5.5	11.5	10.0	1.4
2026	0.3	1.1	1.5	2.5	8.1	0.4	1.8	2.7	5.2	8.6	0.5	2.4	4.5	9.2	9.3	0.0
2027	0.0	0.1	0.2	0.3	6.3	0.1	0.2	0.4	0.7	6.5	0.1	0.3	0.7	1.4	6.7	0.0
2028	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.1	0.1	5.5	0.0
2029	0.0	0.0	0.0	0.0	4.4	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	4.8	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total to 2034	**2.2**	**12.5**	**6.1**	**16.8**	**79.2**	**2.5**	**14.5**	**9.0**	**23.3**	**82.7**	**2.7**	**16.1**	**12.7**	**32.3**	**87.0**	**76.7**
Total to economic limit	**2.2**	**12.4**	**6.0**	**16.7**	**63.3**	**2.5**	**14.4**	**8.9**	**23.1**	**66.3**	**2.7**	**16.1**	**12.7**	**32.2**	**76.7**	

Notes for all Appendix II Tables:

1. Production and costs are shown at gross field level, i.e. 100% of the production and costs.
2. The volumes shown are after deduction of fuel and shrinkage.
3. CAPEX is the same in all three cases (Low, Best and High).
4. Totals are in MMBbl for oil and Bscf for gas.

Appendix III
CAPEX Breakdowns

Table AIII.1: CAPEX Breakdown for Obaiyed (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Flank Horizontal Well	7				18.0	24.0			
Vertical Well	5		5.6	13.4					
Recompletion/WO	13		8.8	1.1	2.2	2.2			
Gas Well Hook-up	12		2.4	3.6	3.6	4.8			
LLP Compressor Phase 1 Project (NFA)			2.8	4.7	7.3	3.7			
Life Extension Project (NFA)			1.8	3.0	4.8	2.4			
Asset Integrity Project (NFA)			1.8	3.0	3.3	2.8	1.7	0.7	
Contamination + Well Integrity Project (NFA)			0.2	0.2	0.2	0.2	0.2		
LLP Compressor Phase 1 Project (Infill)			0.9	1.6	2.4	1.2			
LLP Compressor Phase 2 (Infill)			0.6	1.0	1.6	0.8			
Total (US$MM)			**24.9**	**31.5**	**43.5**	**42.3**	**1.9**	**0.7**	

Table AIII.2: CAPEX Breakdown for NM (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	13				21.1	33.8			
Gas Well Hook-up	16				9.7	9.7			
NM Development Project (FO)			8.8	43.8	5.8	2.7	2.7		
Exploration CAPEX		1.5							
Total (US$MM)		**1.5**	**8.8**	**43.8**	**36.6**	**46.1**	**2.7**		

Table AIII.3: CAPEX Breakdown for NUMB (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	7					29.5			
Gas Well Hook-up	7					8.5			
Total (US$MM)						**38.0**			

Table AIII.4: CAPEX Breakdown for BED2 (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	10	4.5		6.0	4.5				
Horizontal Well	1	3.5							
Injector									
Gas Well Hook-up									
Oil Well Hook-up	11	1.6		1.6	1.2				
Injector Hook-up									
LLP Compressor Project (NFA)		2.3	7.0						
Contamination + Well Integrity Project (NFA)			0.1	1.1	1.1	0.2	0.2		
Total (US$MM)		**12.0**	**7.1**	**8.7**	**6.8**	**0.2**	**0.2**		

Table AIII.5: CAPEX Breakdown for BED3 (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	17	3.0	19.4	3.0					
Injector	5	1.0	3.9						
Re-Perf	1		0.3						
Gas Well Hook-up									
Oil Well Hook-up	18	1.2	5.3	0.8					
Injector Hook-up	5	0.2	0.8						
Sitra PWRI at BED3 Project (NFA)		8.0							
LLP Compression Project (NFA)		3.0							
Asset Integrity (NFA)			3.8	6.4	7.1	6.1	3.6	1.5	
Contamination + Well Integrity (NFA)			0.2	1.3	1.3	0.3	0.3		
Mercury Removal Facility (NFA)		4.5							
Electrification Project (NFA)			2.5	3.7	3.7	2.5			
LP Oil AG LLP tie-in Project (Infill)			0.8						
2 x Separators BED3 Oil Project (Infill)			0.6	0.6					
Additional Export Pump Project (Infill)			1.5	1.5					
Electrification Project (Infill)			0.5	0.8	0.8	0.5			
Total (US$MM)		**20.9**	**39.6**	**18.1**	**12.9**	**9.4**	**3.9**	**1.5**	

Table AIII.6: CAPEX Breakdown for Sitra (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	19	5.3	14.1	14.1					
Horizontal Well	5		17.6						
Injector	5		1.9	2.9					
Gas Well Hook-up	1	1.2							
Oil Well Hook-up	23	0.8	5.3	3.3					
Injector Hook-up	5		0.4	0.6					
Contamination + Well Integrity Project (NFA)			0.1	0.3	0.3	0.3			
Total (US$MM)		**7.3**	**39.4**	**21.2**	**0.3**	**0.3**			

Table AIII.7: CAPEX Breakdown for AESW (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Karam Gas Well	14		36.0	48.0	28.0				
Vertical Well	41	12.0	6.0	13.5	19.4	10.5			
Injector	11			3.9	3.9	2.9			
Gas Well Hook-up	21	2.4	4.8	7.3	6.1				
Oil Well Hook-up	16	2.4	1.6	3.7	4.9	2.9			
Injector Hook-up	11			0.8	0.8	0.6			
Bahga Electrification Project (NFA)		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Baraq Electrification Project (NFA)		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Contamination + Well Integrity Project (NFA)			0.1	0.1	0.1	0.1			
AESW Electrification Project (NFA)						1.6	2.4	2.4	1.6
Barq Evaporation Pond Project (NFA)			0.5						
Barq-Sitra Water Pumps & Line Project (NFA)				1.0					
Bahga Evaporation Pond Project (NFA)			1.4						
Gas Debottlenecking Project (Infill)			1.5	1.5					
AESW Electrification Project (Infill)						0.6	0.9	0.9	0.6
Assil G/L Separator Project (Infill)				0.6					
Barq Leased Separator Project (Infill)						0.5			
Barq Export Line BED3 Looping Project (Infill)					1.4				
Barq G/L Separator Project (Infill)				0.6					
Bahga Separator G/L/FWKO Project (Infill)				1.7					
Bahga Leased Separator Project (Infill)				0.5					
Bahga Water Disposal Project (Infill)					2.6				
Total (US$MM)		**17.4**	**52.5**	**83.6**	**67.7**	**20.2**	**3.8**	**3.8**	**2.8**

Table AIII.8: CAPEX Breakdown for NAES (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	2					12.0			
Injector									
Gas Well Hook-up	2					2.4			
Total (US$MM)						**14.4**			

Table AIII.9: CAPEX Breakdown for NEAG-Ext (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	15			20.9	1.5				
Injector	6			2.9	2.9				
Oil Well Hook-up	15			5.7	0.4				
Injector Hook-up	6			0.6	0.6				
Accelerated WD Project (NFA)		0.8							
NEAG2 Electrification Project (NFA)			0.8	0.8					
Contamination + Well Integrity Project (NFA)			0.2	1.7	1.7	0.7	0.7		
Asset Integrity Project (NFA)			0.8	1.3	1.4	0.5			
NEAG1 WD Ph3 + NEAG2 WD Project (Infill)					0.6	0.6			
Total (US$MM)		**0.8**	**1.7**	**33.9**	**9.1**	**1.8**	**0.7**		

Table AIII.10: CAPEX Breakdown for NEAG-Tiba (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	6		9.5			4.8			
Horizontal Well	9	7.4	3.7		11.1	11.1			
Injector	8		1.0		1.9	4.8			
Oil Well Hook-up	15	0.8	2.0		1.2	2.0			
Injector Hook-up	8		0.2		0.4	1.0			
JG WD Ph2 + spare WD well Project (NFA)			1.7	1.7					
Additional Water Source Wells Project (NFA)			1.0	1.0					
JG Electrification Project (NFA)			0.4	0.4	0.4	0.4	0.4		
Contamination + Well Integrity Project (NFA)			0.1	0.7	1.7	1.7	0.7		
JG Electrification Project (Infill)			0.4	0.4	0.4	0.4	0.4		
Total (US$MM)		**8.2**	**17.2**	**4.1**	**19.7**	**26.1**	**1.4**		

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Appendix IV
Reserves and NPVs as at 31st December 2020

Cairn Energy Plc
10 June 2021

As mentioned in the Introduction, given the time that has elapsed since the Effective Date of the estimates of Reserves and NPVs presented in the CPR, to meet the requirements of the FCA, GaffneyCline has included tables showing the Reserves that would remain as at 31st December 2020 and the corresponding NPVs at that date. For this purpose, GaffneyCline has only considered the cash flows after December 31st 2020, but has not made any other adjustment to the forecasts made for the Reserves cases as at 31st December 2019. This is considered a reasonable assumption given that actual production from January to December 2020 has been comparable, in the aggregate, with GaffneyCline's estimates made as at 31st December 2019.

An updated Brent crude oil price scenario has been used for the economic limit, NPV and entitlement calculations, namely GaffneyCline's own 1Q 2021 Brent Crude oil price scenario shown in Table AIV.1.

Table AIV.1: 1Q 2021 Brent Crude Oil Price Scenario

Year	Price (US$/Bbl)
2021	51.38
2022	54.00
2023	57.00
2024	60.00
2025+	+2% per annum

Resulting Reserves volumes are shown in Table AIV.2 and NPVs in Table AIV.3.

Since 31st December 2020, GaffneyCline has reviewed information regarding the performance of the Assets in 2020, and compared forecasts (including production and costs) against those set out in the CPR. GaffneyCline notes the deferral in the implementation of the drilling schedule planned by the Consortium. Based on the information available, GaffneyCline expects this deferral to defer some production, particularly in 2021, which could impact the NPVs but is unlikely to have a material impact on the Reserves. Additionally, the reduction in NPVs will be offset by the recovery in oil prices since the beginning of 2021, which makes the scenario shown in Table AIV.1 now appear conservative in the short term. GaffneyCline therefore believes that the Reserves and NPVs as at 31st December 2020 reported herein remain valid in the aggregate.

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Table AIV.2: Summary of Reserves[3] as at 31st December 2020

(b) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	15.1	20.2	24.8	100.0	5.8	7.1	8.1	50.0	2.9	3.5	4.0
NUMB	0.1	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.0	0.0	0.0
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.7
BED 2	1.0	3.8	6.0	100.0	0.4	1.7	2.4	50.0	0.2	0.8	1.2
BED 3	7.8	12.0	16.9	100.0	3.6	5.5	6.8	50.0	1.8	2.7	3.4
Sitra	0.0	9.9	15.2	100.0	0.0	4.6	6.5	50.0	0.0	2.3	3.2
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	5.1	7.9	11.7	52.0	1.4	1.8	2.3	26.0	0.7	0.9	1.1
NEAG Ext.	6.0	9.9	15.1	52.0	1.7	2.6	3.6	26.0	0.8	1.3	1.8
AESW	15.1	27.4	42.6	40.0	2.5	4.5	5.7	20.0	1.3	2.3	2.8
Total	**55.2**	**101.3**	**152.2**		**17.4**	**31.3**	**40.7**		**8.7**	**15.7**	**20.4**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	320.1	378.2	435.0	100.0	130.0	140.4	150.2	50.0	65.0	70.2	75.1
NUMB	9.1	9.6	9.9	100.0	4.2	4.4	4.6	50.0	2.1	2.2	2.3
NM	46.4	76.8	128.0	100.0	18.5	27.4	34.7	50.0	9.3	13.7	17.3
BED 2	4.1	33.4	67.0	100.0	1.8	15.1	27.6	50.0	0.9	7.5	13.8
BED 3	36.7	49.6	63.3	100.0	16.9	22.8	25.7	50.0	8.5	11.4	12.9
Sitra	0.0	22.1	31.4	100.0	0.0	10.2	13.5	50.0	0.0	5.1	6.7
NAES	0.0	23.2	35.3	100.0	0.0	10.2	15.5	50.0	0.0	5.1	7.8
NEAG Tiba	12.1	18.3	27.2	52.0	3.3	4.2	5.5	26.0	1.7	2.1	2.8
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	418.3	547.6	729.5	40.0	68.5	89.4	97.4	20.0	34.3	44.7	48.7
Total	**846.8**	**1,158.8**	**1,526.6**		**243.3**	**324.1**	**374.6**		**121.6**	**162.0**	**187.3**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Reserves are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

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Table AIV.3: Summary of Post-Tax NPV10[2] of Future Cash Flow from Reserves, as at 31st December 2020

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	216.5	276.0	332.8	108.2	138.0	166.4
NUMB	11.5	12.2	12.7	5.7	6.1	6.4
NM	-6.3	64.5	131.1	-3.2	32.2	65.6
BED 2	4.7	27.3	50.6	2.3	13.6	25.3
BED 3	26.3	119.8	178.3	13.2	59.9	89.1
Sitra	0.0	76.7	161.9	0.0	38.4	81.0
NAES	0.0	3.7	11.4	0.0	1.8	5.7
NEAG Tiba	12.9	29.2	47.7	6.5	14.6	23.9
NEAG Ext	14.0	33.4	57.0	7.0	16.7	28.5
AESW	89.4	188.8	228.1	44.7	94.4	114.1
Total	**368.9**	**831.4**	**1,211.7**	**184.5**	**415.7**	**605.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. NPVs are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
3. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Appendix V
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 June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

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

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

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

Class/Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

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

Table 3—Reserves Category Definitions and Guidelines

<table>
<tr><th>Category</th><th>Definition</th><th>Guidelines</th></tr>
<tr><td>Proved Reserves</td><td>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.</td><td>If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.

The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved.

Reserves in undeveloped locations may be classified as Proved provided that:

A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.

B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.</td></tr>
<tr><td>Probable Reserves</td><td>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.</td><td>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.</td></tr>
</table>

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

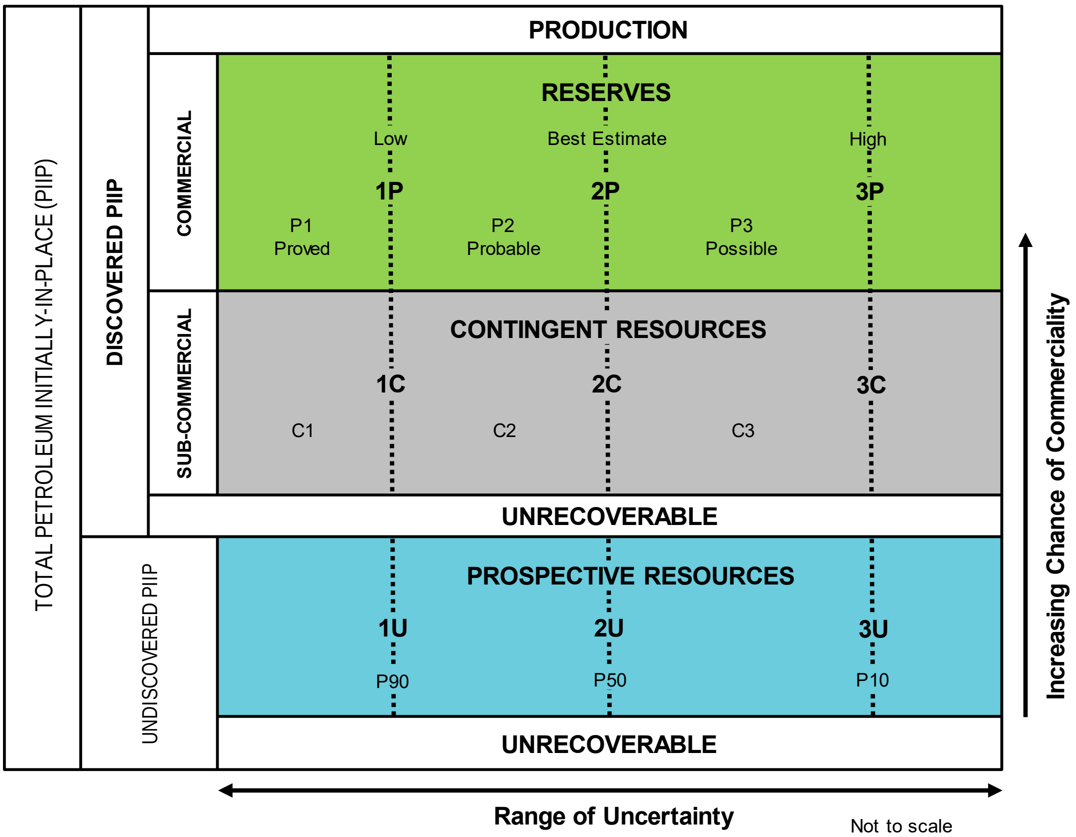

Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY