

Independent Evaluation of Reserves and Certain Contingent Resources held by Serica Energy plc

as of 30 June 2026

Prepared For: Serica Energy (UK) Limited

By: Sproule ERCE



**Sproule
ERCE**

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16 October 2026

Serica Energy (UK) Limited
4th Floor, 72 Welbeck Street
London, W1G 0AY
United Kingdom

Attn: Mr. Rich Hiney, Subsurface Manager, Serica Energy (UK) Limited

Re: Reserves Evaluation Report

In accordance with your instructions, ERC Equipoise Limited (“Sproule ERCE”) has carried out an independent evaluation of the hydrocarbon Reserves and certain Contingent Resources relating to transactions which were completed by Serica Energy plc (the parent company of Serica Energy (UK) Limited (“Serica” or the “Company”)) in 2026 as well as Reserves and certain Contingent Resources acquired by subsidiaries of Serica in the UK North Sea as part of the transaction between Serica and Spirit Energy (the “Spirit Transaction”). The Spirit Transaction was completed on 1 October 2026. The effective date of this report is 30 June 2026 (the “Effective Date”) and the report was prepared for the Company between August 2026 and September 2026 for the purpose of supporting the transfer of Serica’s listing of its Ordinary Shares from the Alternative Investment Market (“AIM”) to the Main Market of the London Stock Exchange (“LSE”).

The preparation date of this report is 16 October 2026. This date is subsequent to the Effective Date and refers to the last date on which information, relating to the period ending on the Effective Date, was received and considered in the preparation of this report. The issuance date (“Issuance Date”) of this report is the same as the date indicated at the top of this letter.

The reserves and resources data presented in this report, which includes reserve quantities, net present values and contingent resource quantities, were prepared in accordance with the classifications and definitions of the Petroleum Resources Management System (“SPE-PRMS”), sponsored by Society of Petroleum Engineers (“SPE”), World Petroleum Council (“WPC”), American Association of Petroleum Geologists (“AAPG”), Society of Petroleum Evaluation Engineers (“SPEE”), Society of Exploration Geophysicists (“SEG”), Society of Petrophysicists and Well Log Analysts (“SPWLA”), and the European Association of Geoscientists & Engineers (“EAGE”).

The oil reserves and contingent resources are presented in millions of barrels, at stock tank conditions. The natural gas reserves and contingent resources are presented in billions of cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit. The natural gas liquids reserves and contingent resources are presented in millions of barrels, at base conditions of 60 degrees Fahrenheit and equilibrium pressure.

The price forecasts that formed the basis for the revenue projections in the evaluation were based on Sproule ERCE's 30 June 2026 pricing model.

Disclaimer

This material is produced by Sproule ERCE based on the instructions and data from the Company to provide Sproule ERCE's professional and independent opinion to the Company and is thus prepared exclusively for the Company's sole benefit and not for the benefit of any third party.

The analysis of individual entities as reported herein was conducted within the context and scope of an evaluation of a unique group of entities in aggregate. Use of this report outside of this scope may not be appropriate. The estimates of reserves, future net revenue and contingent resources for individual entities or properties may not reflect the same confidence level as estimates of reserves, future net revenue and contingent resources for all entities, due to the effects of aggregation.

Sproule ERCE reserves the right to review all calculations made, referred to, or included in this report and to revise the estimates as a result of erroneous data supplied by the Company or information that exists but was not made available to us, which becomes known subsequent to the preparation of this report.

The accuracy of reserves estimates and associated economic analysis, and contingent resources, is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

The cashflow modelling results presented in this report represent forecasts of the estimated production, revenues, royalties and costs based on a select set of entities yielding reserves which are economically producible. This model and the operating assumptions implied may not represent the actual operating practices of a company and the presentation may not include all petroleum operations, including but not limited to inactive and uneconomic properties. Although these cash flows may form an integral part of a proforma operating statement and forecast estimation, without consideration for other economic criteria and items which may not be included in the results presentation, they are not to be construed as Sproule ERCE's opinion of a proforma operating statement for the entity group evaluated.

The net present values of the reserves presented in this report represent discounted future cash flow values at several discount rates. Though net present values form an integral part of fair market value estimations, without consideration for other economic criteria, they are not to be construed as Sproule ERCE's opinion of fair market value.

This report contains forward-looking statements including expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

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BOEs may be misleading, particularly if used in isolation. A standardised BOE conversion ratio of 5.8 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the preparation of this evaluation, field inspections of the properties were not performed. The relevant engineering and geoscience data were made available by the Company or obtained from public sources and the non-confidential files at Sproule ERCE. No material information regarding the reserves evaluation would have been obtained by an on-site visit.

Due to rounding, certain totals may not be consistent from one presentation to the next.

Qualifications

Sproule ERCE is an independent consultancy specialising in geoscience evaluation, engineering, and economic assessment. Sproule ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report and Sproule ERCE will receive no other benefit for the preparation of this report. Sproule ERCE and all contributing members of this report consider themselves to be independent from the Company, as is defined in SPE-PRMS.

Sproule ERCE has the relevant and appropriate qualifications, experience, and technical knowledge to appraise professionally and independently the assets. The preparation of this letter has been supervised

by Mr. Matteo Caniggia, Head of Reservoir Engineering, EAA at Sproule ERCE. Mr. Caniggia is a Qualified Reserves Evaluator and a member in good standing with SPEE, deeming him to possess the required competencies to prepare this report.

Yours faithfully,

Matteo Caniggia

Signed with ConsignO Cloud (2026/10/16)
Verify with verifio.com or Adobe Reader.



Mr. Matteo Caniggia

Head of Reservoir Engineering EAA

1. Executive Summary

Serica Energy plc completed its acquisition of TotalEnergies' interest in the Greater Laggan Area ("GLA") on 26 March 2026 and its acquisition of ONE Dyas' interests in the Catcher Area and Golden Eagle Area Development ("GEAD") on 11 June 2026. Serica Energy plc has also acquired petroleum interests in certain assets located in the UK North Sea from Spirit Energy, with the transaction completed on 1 October 2026.

A summary of Serica's interests acquired through 2026 and covered in this evaluation is presented in Table 1.1.

Table 1.1: Summary of Licence Interests

Country	Licence	Working Interest	Operator	Hub	Field(s)	Status
United Kingdom	P911 P1159 P1195 P1453 P1673	40.00%	Serica	Greater Laggan Area ¹	Laggan	Producing
					Glenlivet	Producing
					Tormore	Producing
					Edradour	Shut-in
					ERSS ²	Discovery
	P1430	10.00%	Harbour Energy	Catcher Area ³	Catcher	Producing
					Burgman	Producing
					Varadero	Producing
	P300 P928	5.21%	CNOOC	Golden Eagle Area Development ³	Golden Eagle	Producing
					Solitaire	Producing
					Peregrine	Producing
	P468 P1186 P83 P132 P455 J03b J06a	100.00%	Spirit Energy	Greater Markham Area ⁴	Chiswick	Producing
		92.50%	Spirit Energy		Grove	Producing
		100.00%	Spirit Energy		Kew	Producing
		4.00%	TotalEnergies		J3C	Producing
		100.00%	TotalEnergies		Markham	Shut-in
	P1055 P1731	15.00%	Ithaca Energy	-	Cygnus ⁴	Producing

¹ Serica's interest in the GLA assets was acquired on 26 March 2026 from TotalEnergies. On completion of the acquisition Serica became the Operator. The GLA assets include the onshore Shetland Gas Plant ("SGP").

² The Edradour Royal Sovereign and Spinnaker ("ERSS") discovery, formerly known as the Glendronach discovery.

³ Serica's interests in the Catcher Area and GEAD assets were acquired on 11 June 2026 from ONE Dyas.

⁴ Serica's interests in the Greater Markham Area ("GMA"), Cygnus, Clipper South, Galleon, Eris and Ceres assets were acquired on 1 October 2026 from Spirit Energy. On completion of the acquisition, Serica became the Operator in the Chiswick, Grove, Kew, Ceres and Eris fields.

Country	Licence	Working Interest	Operator	Hub	Field(s)	Status
	P8 P465 P1909	25.00%	INEOS	-	Clipper South ⁴	Producing
	P8 P130	8.40%	Shell	-	Galleon ⁴	Producing
	P1060 P1241	56.00%	Spirit Energy	-	Eris ⁴	Producing
	P1241 P302	90.00%	Spirit Energy	-	Ceres ⁴	Shut-in

1.1 Asset Overview and Highlights

Greater Laggan Area – Serica interest 40.00% (with operatorship)

The Laggan, Tormore, Edradour and Glenlivet fields (collectively the “Greater Laggan Area” or “GLA”) are located between 75 km and 125 km northwest of the Shetland Islands on the UK Continental Shelf (“UKCS”). Serica is the Operator. Serica’s interest in the GLA assets includes the onshore Shetland Gas Plant (“SGP”).

The fields are developed through a dedicated subsea pipeline infrastructure to the SGP. Gas is exported via the Shetland Island Regional Gas Export pipeline (“SIRGE”) and the Frigg UK Association (“FUKA”) pipeline to St Fergus where natural gas liquids (“NGL”) are extracted, whilst the condensate is exported to the Sullom Voe Terminal (“SVT”).

Gas is produced from Palaeocene aged deep marine turbidite reservoirs and Cretaceous aged deep marine mass flow deposits, with variable condensate-gas ratio (“CGR”).

Production commenced in 2016. A low-pressure (“LP”) compression project was completed in 2023 at the SGP. Regular pigging activities are required to liquid sweep flowlines; in the past year these have been occurring approximately every six weeks and last several days. There is a short period of flush production each time production is restarted after a pigging operation. Since the tie-in of the third party Victory field, the production shortfalls due to pigging operations have been reduced.

In June 2026, the average gross wellhead gas and condensate rates were 32 MMscf/d and 115 bbl/d from eight active wells. Cumulative gas and condensate production is 845 Bscf and 12.7 MMstb and the present day gas recovery factors in the fields are between 38% and 76%.

In Q4 2025, the Victory field (a single well tie back owned by a third party) was tied into the GLA infrastructure causing a back-out effect on GLA production. A compensation mechanism between the GLA and Victory partners is in place to account for this.

The Developed Reserves comprise continued production from existing wells in the Laggan, Tormore and Glenlivet fields and, based on guidance from Serica, exclude any compensated volumes from Victory partners. There are no Undeveloped Reserves.

Contingent Resources have been assigned to three projects: the ERSS discovery, a Tormore infill well and extension of the economic life of the SGP (and by inference of the GLA fields) due to the inclusion of additional projects (namely the ERSS discovery, Tormore infill well and the proposed third-party tieback of the Tornado discovery).

The ERSS gas accumulation, with reservoirs located above and beneath the Edradour Field, was discovered in 2018 and work is ongoing to determine the commerciality of a single well development. An infill opportunity has been identified in the Tormore Field, and work is ongoing to integrate recent 4D seismic data, update static and dynamic models and evaluate the opportunity. The third-party-owned Tornado discovery has included GLA as the preferred export route in its Concept Select Report submitted to the North Sea Transition Authority (“NSTA”). If the project is approved, first gas is expected in 2029. Together, these projects, if executed, would be expected to extend the economic life of the SGP and the GLA fields.

Catcher Area – Serica interest 10.00%

The Catcher, Varadero and Burgman Fields (collectively the “Catcher Area”) are located to the west of the Central Graben within the UKCS, approximately 170 km southeast of Aberdeen. Harbour Energy is the Operator.

Medium quality oil is trapped structurally and stratigraphically in Tertiary age Cromarty and Tay Member sandstones. Originally deposited as deep marine channels and fans, the reservoirs have been re-mobilised and fluidised, leading to a complex architecture of sandbodies and injectites.

Production commenced in late 2017 from the Catcher Field, with production from Varadero and Burgman following within six months. A peak production rate of approximately 65,000 stb/d was achieved between late 2018 and mid-2019. All fields are tied back to a leased floating production, storage and offloading vessel (“FPSO”). Oil is exported via a shuttle tanker; excess gas after fuel consumption is either evacuated via the Fulmar Gas Line (“FGL”) to St. Fergus or re-injected into certain areas of the reservoir via production wells. To date, 21 subsea development wells (17 producers and four water injectors) have been drilled in the Catcher Area.

In June 2026, the average gross wellhead oil and gas production rates from the Catcher Area were 19,200 stb/d (at a water cut of 84.7%) and 13.5 MMscf/d from 17 active wells. There are four active water injection wells supporting production with a combined water injection rate of 118,000 bbl/d. Since the start of 2025, 1.1 Bscf of gas has been re-injected. Cumulative oil and gas production is 118 MMstb and

49 Bscf (9.8 Bscf of which has been re-injected), representing a present-day oil recovery factor of approximately 38% at the area level.

The Developed Reserves comprise continued production from existing wells as well as a future depressurisation project, involving dropping the reservoir pressure below bubble point by stopping or reducing water injection to induce solution gas and gas cap expansion drive. The timing of the project is dependent on the forecast date at which the FPSO becomes fuel gas deficient. There are no Undeveloped Reserves.

Contingent Resources have been assigned to four projects. Two infill opportunities, one in the Varadero Field and one in the Burgman Field, have been identified and there are ongoing studies to evaluate their commerciality⁵. Other projects include a water shut-off opportunity in Well CP4 and an organic oil recovery project ("OOR").

Golden Eagle Area Development – Serica interest 5.21%

The Golden Eagle, Peregrine and Solitaire Fields (collectively the "Golden Eagle Area Development" or "GEAD") are located to the west of the Central Graben within the UKCS, approximately 110 km northeast of Aberdeen. A unitisation agreement is in place across the two licences covering the fields (P928 block 20/1a North and P300 block 14/26a Rest of Block). China National Offshore Oil Corporation ("CNOOC") is the Operator. Oil is exported to the Flotta Oil terminal via the Piper and Claymore fields; gas was exported to St. Fergus via the Scottish Area Gas Evacuation ("SAGE") system but the field is now fuel gas deficient and there is no gas export.

The Golden Eagle and Peregrine Fields contain a light oil structurally and stratigraphically trapped in Upper Jurassic to Lower Cretaceous-aged turbidite reservoirs (the Punt and Burns Sandstones). The Solitaire Field contains a medium oil structurally trapped in the Burns reservoir.

First production occurred in 2014 and a plateau production rate of approximately 75,000 stb/d was reached in 2016; GEAD production came off plateau in late 2017. Produced oil is exported via the Flotta Pipeline System and terminal; all produced gas is used as fuel with minor excess flaring. The most recent infill drilling campaign in 2023/24 comprised the drilling of three new production wells and one water injection well. The campaign yielded poorer than expected results, with the new production wells experiencing high water cuts from the onset.

In June 2026, the average wellhead oil and gas production rates from the area were 8,640 stb/d (at a water cut of 91%) and 2 MMscf/d from 18 online producing wells. There are five active water injection

⁵ Between the Effective Date and Issue Date of this report, in August 2026, the field partners approved the Varadero West infill well.

wells supporting production in the Golden Eagle Field with a combined average water injection rate of 88,073 bbl/d in June 2026. Cumulative oil and gas production is 148 MMstb and 32 Bscf, representing a present-day oil recovery factor of approximately 44%.

Through Q2 2026, three mud acid stimulation workovers were successfully carried out, adding approximately 240 stb/d of oil production.

The Developed Reserves comprise continued production from existing wells. There are no Undeveloped Reserves.

Contingent Resources have been assigned to two projects. Both projects target improved recovery in the Punt reservoir in the Golden Eagle Field by drilling a new water injector and converting an existing producer to water injection. The opportunities are under ongoing evaluation by the Operator⁶.

Greater Markham Area – various Serica interests (with operatorship)

The Greater Markham Area (“GMA”) straddles the maritime boundary between the United Kingdom and the Netherlands within UK blocks such as 49/5 and the adjacent Dutch sectors. The hub comprises the Spirit Energy-operated Markham, Chiswick, Grove and Kew gas Fields and the non-operated J3C gas field. Additional third-party fields (K01-A and K04a-D) share the facilities. The Markham J6A platform acts as a processing hub and four pipelines ultimately deliver gas to Den Helder in the Netherlands. As at the Effective Date Spirit Energy was the Operator with operatorship scheduled to transfer to Serica on completion of the Spirit Transaction.

The GMA fields contain dry natural gas, with minimal associated condensate. Reservoirs comprise poor to moderate quality tight fluvial sandstones of the Upper Carboniferous Westphalian A-C succession at Chiswick, Kew and Grove, and moderate quality aeolian sandstones of the Lower Permian Rotliegend Group at J3C.

Development of the Greater Markham Area began in the 1990s from the central Markham Field, which, as at the Effective Date, is no longer in production.

In June 2026, average wellhead production rates from the area were around 45 MMscf/d of gas and 367 bbl/d of condensate from nine active wells. Cumulative gas production from the active fields is approximately 704 Bscf, with current recovery factors ranging from 37% to 95% for the different fields.

The Grove and J3C Fields have historically been produced to the Low-Low Pressure (“LLP”) compressor, whilst the Chiswick and Kew Fields are produced to the LP compressor. The LLP compressor failed in

⁶ Between the Effective Date and Issue Date of this report, in August 2026, the field partners approved the project to convert Well G15z to water injection.

July 2025 which led to the shut-in of the Grove and J3C Fields. However, in October 2025 the Grove Field was successfully put on production through the LP compressor. The LLP compressor was successfully reinstated at the end of April 2026 after a 17-day shutdown on the J6A platform; J3C production was subsequently restarted in May.

In late January 2026, all production from the GMA fields was stopped due to a failure of the diesel firewater pump on the J6A platform; production was restarted in early March 2026.

The Developed Reserves comprise continued production from existing producers. There are no Undeveloped Reserves.

Contingent Resources have been assigned to one project, related to the drilling of an infill well in the eastern area of the Grove accumulation, where gas is not expected to be efficiently drained by existing producing wells.

Cygnus Field – Serica interest 15.00%

The Cygnus Field is located approximately 150 km from the Lincolnshire coastline in the Southern North Sea, at the northern end of the Southern Permian basin. Ithaca Energy is the Operator. Gas is exported via a 55 km pipeline to the Esmond Transmission System pipeline, which terminates at the Bacton terminal in the UK.

The field contains gas in two reservoirs. The primary reservoir is the Lower Permian age Leman Sandstone Formation, comprising poor to fair quality fluvial and aeolian sandstones deposited in an arid environment. A secondary reservoir, present in certain fault blocks, occurs within the Upper Carboniferous Lower Ketch Member of the Schooner Formation and comprises generally higher quality fluvial sandstones, with reservoir quality ranging from poor to good.

The field was discovered in 1988. In June 2026, the average wellhead production rates from the field were around 164 MMscf/d of gas and 312 bbl/d of condensate from twelve active wells. Cumulative gas production from the field is approximately 732 Bscf, representing a present-day gas recovery factor of approximately 61%.

The produced gas is lean and requires blending with richer gas for export. Recent agreements with third parties should ensure that production from Cygnus will not be restricted by a lack of blend gas, as experienced in the past.

The Developed Reserves comprise continued production from existing producers, including the most recently drilled 12th and 13th wells, which were brought onstream in December 2025 and May 2026 respectively. Some instability of existing wells (Wells A4z, B3, B4) is being observed at low gas rates and the Operator is continuing in active management of these wells and remedial activity planning.

The 12th well, Well 44/12a-7y (A7y), encountered depleted reservoir, and production performance has been below the Operator's pre-drill expectation, with the well ceasing to flow in May 2026 due to water production⁷. The 13th well, Well 44/12a-8z (A8z), encountered good quality reservoir above pre-drill prognosis and came onstream at over 40 MMscf/d. Development infill drilling is ongoing on Cygnus, and Undeveloped Reserves are attributed to two wells planned to be drilled and brought onstream in October 2026 and March 2027.

Contingent Resources have been assigned to one further well, planned for late 2027 as either a sidetrack fallback option of a well targeting a prospective area or a standalone development well.

Clipper South Field – Serica interest 25.00%

The Clipper South field is located in the Southern North Sea approximately 100 km to the east of the Theddlethorpe gas terminal. INEOS Energy is the Operator. Production was originally routed via the Lincolnshire Offshore Gas Gathering System ("LOGGS") complex to the Theddlethorpe Gas Terminal but is now exported via Shell's Clipper complex to the Bacton Terminal.

Gas is contained in the Leman Sandstone Formation of relatively tight reservoir comprising aeolian, fluvial and sandy sabkha sediments.

The field was discovered in 1983 and first gas was achieved in 2012. A total of four development wells have been drilled, all online at the Effective Date. In June 2026, the average wellhead gas production rate from the field was around 22 MMscf/d. Cumulative gas production from the field is approximately 229 Bscf, representing a present-day gas recovery factor of approximately 71% (against the portion of gas initially in place ("GIIP") interpreted to be connected to the producing wells). Produced gas is very dry, with a CGR of <1 stb/MMscf.

The developed Reserves comprise continued production from existing producers. There are no undeveloped Reserves.

Contingent Resources have been assigned to one further well, planned to target the undeveloped northwestern area of the field.

Galleon Field – Serica interest 8.40%

The Galleon field is located within the Sole Pit area of the Southern Gas Basin, around 65 km from the coast of East Anglia. Shell is the operator. Gas is exported to Bacton via the Sole Pit gas export line.

⁷ Between the Effective Date and Issue Date of this report, in August 2026, the well was successfully reinstated at ~30 MMscf/d following the injection of nitrogen into the well.

Lean gas is contained in the Lower Permian-aged Leman Sandstone Formation. The reservoir comprises heterogeneous aeolian-dominated sandstones characterised by poor-moderate reservoir quality. The field was developed in two stages, with first gas achieved in October 1994 and November 1998 respectively. A total of 18 wells have been drilled and historical production peaked in excess of 200 MMscf/d in the early 2000s from two main platforms, both tied back to the Barque and Clipper facilities via dedicated pipelines.

In June 2026, the average wellhead gas production rate from the field was around 23 MMscf/d. Cumulative gas production from the field is approximately 829 Bscf, representing a present-day gas recovery factor of approximately 25% (against the Operator's volumetric estimate of GIIP for the full field). Produced gas is very dry, with a CGR of <1 stb/MMscf.

The Developed Reserves comprise continued production from existing producers, the majority of which exhibit cyclic behaviour. There are no Undeveloped Reserves.

Eris Field – Serica interest 56.00% (with operatorship)

The Eris field is located in Blocks 47/8c, 47/9b, 47/9c and 47/3h on the northwest margin of the Southern Permian gas basin and on the edge of the Sole Pit basin at its western margin; it is ~7 km northwest of the Mercury Field (which it is tied back to) and 5 km west of the Ceres Field⁸. As at the Effective Date Spirit Energy was the Operator with operatorship scheduled to transfer to Serica at completion of the Spirit Transaction.

The Eris Field was discovered in August 2007 when gas was encountered in the Leman Sandstone Formation of the Lower Permian Rotliegend Group.

The field was jointly developed with the neighbouring Ceres Field, also operated by Spirit Energy, as a single subsea well, tied back 8.5 km with a 6" production flow-line to the Mercury manifold and from there to Neptune and onshore to Dimlington via the Cleeton platform.

First gas was achieved in 2010. In June 2026, the average wellhead gas and condensate production rates from the field were around 2.0 MMscf/d and 2 stb/d, respectively. Cumulative gas production from the field is approximately 68 Bscf, representing a present-day gas recovery factor of approximately 81%.

⁸ Spirit Energy's interest in the Ceres field is included in the Spirit Transaction. However, the Ceres field was unable to return to production following a shutdown in June 2026 and the field partners are currently exploring future options, one of which is to declare CoP. Serica has instructed Sproule ERCE to exclude the Ceres field from its evaluation.

There are no Reserves attributed to the field as future production was deemed to be uneconomic at the 2P level of confidence after Determination of Commerciality under PRMS. Future production from the existing well is classified as Contingent Resources.

1.2 Reserves

Under PRMS 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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).

The Reserves are reported on a field gross, Company Working Interest and Company Net Entitlement basis as at 30 June 2026. Under PRMS, it is the Company's Net Entitlement that should be reported as the entity's Reserves. Both developed and undeveloped Reserves are reported for each asset/area and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves using a standardised conversion of 5,800 scf per barrel of oil equivalent ("boe").

A summary of the Developed Reserves is presented in Table 1.2 and a summary of the Undeveloped Reserves is presented in Table 1.3. A summary of the Total Reserves (developed plus undeveloped) is presented in Table 1.4. The tabulated annual production and cost forecasts used as input to the economic model to determine Reserves are included in Appendix 1.

In accordance with the PRMS guidelines, the Cessation of Production ("CoP") date used to estimate Reserves is defined as (a) the end of the last three month period that the maximum cumulative operating cash flow occurs; (b) the end of the technical field life; or (c) the end of the licence period, whichever is projected to occur the soonest.

Table 1.2: Developed Reserves as at 30 June 2026

Asset	Gross on Licence			Company Working Interest			Company Net Entitlement		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Oil + Condensate+ NGLs (MMstb)									
GLA	0.7	0.8	0.8	0.3	0.3	0.3	0.3	0.3	0.3
Catcher	9.8	24.4	29.0	1.0	2.4	2.9	1.0	2.4	2.9
GEAD	5.6	10.4	19.3	0.3	0.5	1.0	0.3	0.5	1.0
Chiswick	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2
Grove	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.1
Kew	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
J3C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cygnus	0.4	0.6	0.8	0.1	0.1	0.1	0.1	0.1	0.1
Clipper South	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Galleon	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Eris	-	-	-	-	-	-	-	-	-
Total	16.7	36.6	50.5	1.8	3.7	4.7	1.8	3.7	4.7
Gas (Bscf)									
GLA	25.3	28.7	29.0	10.1	11.5	11.6	10.1	11.5	11.6
Catcher	0.1	3.0	5.6	0.0	0.3	0.6	0.0	0.3	0.6
GEAD	-	-	-	-	-	-	-	-	-
Chiswick	10.9	17.6	20.4	10.9	17.6	20.4	10.9	17.6	20.4
Grove	2.7	6.8	10.3	2.5	6.3	9.5	2.5	6.3	9.5
Kew	0.5	1.2	1.5	0.5	1.2	1.5	0.5	1.2	1.5
J3C	0.2	1.9	3.7	0.0	0.1	0.1	0.0	0.1	0.1
Cygnus	121.1	188.0	265.5	18.2	28.2	39.8	18.2	28.2	39.8
Clipper South	12.4	21.2	32.8	3.1	5.3	8.2	3.1	5.3	8.2
Galleon	17.7	46.4	61.4	1.5	3.9	5.2	1.5	3.9	5.2
Eris	-	-	-	-	-	-	-	-	-
Total	191.0	314.7	430.2	46.8	74.4	96.9	46.8	74.4	96.9
Oil Equivalent (MMboe)									
GLA	5.1	5.8	5.8	2.0	2.3	2.3	2.0	2.3	2.3
Catcher	9.9	24.9	30.0	1.0	2.5	3.0	1.0	2.5	3.0
GEAD	5.6	10.4	19.3	0.3	0.5	1.0	0.3	0.5	1.0
Chiswick	2.0	3.2	3.8	2.0	3.2	3.8	2.0	3.2	3.8
Grove	0.5	1.2	1.8	0.4	1.1	1.7	0.4	1.1	1.7
Kew	0.1	0.2	0.3	0.1	0.2	0.3	0.1	0.2	0.3
J3C	0.0	0.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Cygnus	21.3	33.0	46.6	3.2	5.0	7.0	3.2	5.0	7.0
Clipper South	2.1	3.7	5.7	0.5	0.9	1.4	0.5	0.9	1.4
Galleon	3.1	8.1	10.7	0.3	0.7	0.9	0.3	0.7	0.9
Eris	-	-	-	-	-	-	-	-	-
Total	49.6	90.9	124.7	9.8	16.5	21.4	9.8	16.5	21.4

Table 1.3: Undeveloped Reserves as at 30 June 2026

Asset	Gross on Licence			Company Working Interest			Company Net Entitlement		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Oil + Condensate+ NGLs (MMstb)									
GLA	-	-	-	-	-	-	-	-	-
Catcher	-	-	-	-	-	-	-	-	-
GEAD	-	-	-	-	-	-	-	-	-
Chiswick	-	-	-	-	-	-	-	-	-
Grove	-	-	-	-	-	-	-	-	-
Kew	-	-	-	-	-	-	-	-	-
J3C	-	-	-	-	-	-	-	-	-
Cygnus	0.1	0.2	0.3	0.0	0.0	0.1	0.0	0.0	0.1
Clipper South	-	-	-	-	-	-	-	-	-
Galleon	-	-	-	-	-	-	-	-	-
Eris	-	-	-	-	-	-	-	-	-
Total	0.1	0.2	0.3	0.0	0.0	0.1	0.0	0.0	0.1
Gas (Bscf)									
GLA	-	-	-	-	-	-	-	-	-
Catcher	-	-	-	-	-	-	-	-	-
GEAD	-	-	-	-	-	-	-	-	-
Chiswick	-	-	-	-	-	-	-	-	-
Grove	-	-	-	-	-	-	-	-	-
Kew	-	-	-	-	-	-	-	-	-
J3C	-	-	-	-	-	-	-	-	-
Cygnus	34.4	62.3	106.9	5.2	9.3	16.0	5.2	9.3	16.0
Clipper South	-	-	-	-	-	-	-	-	-
Galleon	-	-	-	-	-	-	-	-	-
Eris	-	-	-	-	-	-	-	-	-
Total	34.4	62.3	106.9	5.2	9.3	16.0	5.2	9.3	16.0
Oil Equivalent (MMboe)									
GLA	-	-	-	-	-	-	-	-	-
Catcher	-	-	-	-	-	-	-	-	-
GEAD	-	-	-	-	-	-	-	-	-
Chiswick	-	-	-	-	-	-	-	-	-
Grove	-	-	-	-	-	-	-	-	-
Kew	-	-	-	-	-	-	-	-	-
J3C	-	-	-	-	-	-	-	-	-
Cygnus	6.0	10.9	18.8	0.9	1.6	2.8	0.9	1.6	2.8
Clipper South	-	-	-	-	-	-	-	-	-
Galleon	-	-	-	-	-	-	-	-	-
Eris	-	-	-	-	-	-	-	-	-
Total	6.0	10.9	18.8	0.9	1.6	2.8	0.9	1.6	2.8

Table 1.4: Total Reserves as at 30 June 2026

Asset	Gross on Licence			Company Working Interest			Company Net Entitlement		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Oil + Condensate + NGLs (MMstb)									
GLA	0.7	0.8	0.8	0.3	0.3	0.3	0.3	0.3	0.3
Catcher	9.8	24.4	29.0	1.0	2.4	2.9	1.0	2.4	2.9
GEAD	5.6	10.4	19.3	0.3	0.5	1.0	0.3	0.5	1.0
Chiswick	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2
Grove	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.1
Kew	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
J3C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cygnus	0.5	0.8	1.2	0.1	0.1	0.2	0.1	0.1	0.2
Clipper South	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Galleon	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Eris	-	-	-	-	-	-	-	-	-
Total	16.8	36.8	50.8	1.8	3.7	4.7	1.8	3.7	4.7
Gas (Bscf)									
GLA	25.3	28.7	29.0	10.1	11.5	11.6	10.1	11.5	11.6
Catcher	0.1	3.0	5.6	0.0	0.3	0.6	0.0	0.3	0.6
GEAD	-	-	-	-	-	-	-	-	-
Chiswick	10.9	17.6	20.4	10.9	17.6	20.4	10.9	17.6	20.4
Grove	2.7	6.8	10.3	2.5	6.3	9.5	2.5	6.3	9.5
Kew	0.5	1.2	1.5	0.5	1.2	1.5	0.5	1.2	1.5
J3C	0.2	1.9	3.7	0.0	0.1	0.1	0.0	0.1	0.1
Cygnus	155.5	250.3	372.4	23.3	37.5	55.9	23.3	37.5	55.9
Clipper South	12.4	21.2	32.8	3.1	5.3	8.2	3.1	5.3	8.2
Galleon	17.7	46.4	61.4	1.5	3.9	5.2	1.5	3.9	5.2
Eris	-	-	-	-	-	-	-	-	-
Total	225.4	377.0	537.2	52.0	83.7	113.0	52.0	83.7	113.0
Oil Equivalent (MMboe)									
GLA	5.1	5.8	5.8	2.0	2.3	2.3	2.0	2.3	2.3
Catcher	9.9	24.9	30.0	1.0	2.5	3.0	1.0	2.5	3.0
GEAD	5.6	10.4	19.3	0.3	0.5	1.0	0.3	0.5	1.0
Chiswick	2.0	3.2	3.8	2.0	3.2	3.8	2.0	3.2	3.8
Grove	0.5	1.2	1.8	0.4	1.1	1.7	0.4	1.1	1.7
Kew	0.1	0.2	0.3	0.1	0.2	0.3	0.1	0.2	0.3
J3C	0.0	0.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Cygnus	27.3	43.9	65.4	4.1	6.6	9.8	4.1	6.6	9.8
Clipper South	2.1	3.7	5.7	0.5	0.9	1.4	0.5	0.9	1.4
Galleon	3.1	8.1	10.7	0.3	0.7	0.9	0.3	0.7	0.9
Eris	-	-	-	-	-	-	-	-	-
Total	55.7	101.8	143.4	10.8	18.1	24.2	10.8	18.1	24.2

Notes to Tables 1-2 to 1-4:

1. Gross Reserves represent 100% of the Reserves to be recovered from the licence.
2. Company Working Interest Reserves are based on the Working Interest share of the field gross Reserves. As there are no royalties to be deducted, Company Working Interest Reserves are equal to Company Net Entitlement Reserves.
3. Oil and condensate Reserves include NGLs.
4. Gas Reserves are based on sales volumes and exclude fuel and flare.
5. Barrels of oil equivalent are calculated using a standardised conversion of 5,800 scf/boe.
6. Individual values may not add up to the reported totals due to rounding.
7. Cygnus Field Undeveloped Reserves include two planned infill wells.

Reserves evaluation and CoP dates

Sproule ERCE has carried out an economic evaluation of the Reserves at an asset level using Sproule ERCE's forecast commodity prices dated 30 June 2026 (Table 1.5). Sproule ERCE has applied discounts and premiums to the price forecasts based on guidance from Serica. The CoP dates for each asset are presented in Table 1.6.

Table 1.5: Hydrocarbon price forecasts as at 30 June 2026

	Brent Crude Oil Price	NBP Gas Price	UK Allowances (UKA) Price
Year	\$US/bbl	p/therm	GBP/tonne
2026	75.00	106.10	57.15
2027	73.53	87.10	58.87
2028	72.09	71.20	60.60
2029	72.09	71.20	60.42
2030	72.09	71.20	61.38
2031	72.09	71.20	62.21
2032	72.09	71.20	63.15
2033	72.09	71.20	64.20
2034	72.09	71.20	65.35
2035+	72.09	71.20	66.58

Notes:

1. Brent crude oil price, National Balancing Point ("NBP") gas price and UKA price forecasts are based on the Sproule ERCE 30 June 2026 price forecast and are presented in real (2026) terms.
2. Catcher assets trade at a US\$2.50 per barrel discount to Brent.
3. The assets included in the Spirit Transaction trade at a 4.08 p/therm discount to NBP price.
4. NGLs are assumed to be sold at a 30% discount to Brent.

Table 1.6: Asset level CoP dates

Asset	Developed			Developed + Undeveloped		
	1P	2P	3P	1P	2P	3P
GLA	Dec-30	Jun-30	Sep-29	Dec-30	Jun-30	Sep-29
Catcher	Jun-28	Jun-31	Jun-31	Jun-28	Jun-31	Jun-31
GEAD	Jun-29	Jun-31	Dec-34	Jun-29	Jun-31	Dec-34
Chiswick	Dec-28	Jun-29	Jun-29	Dec-28	Jun-29	Jun-29
Grove	Sep-27	Dec-28	Jun-29	Sep-27	Dec-28	Jun-29
Kew	Mar-27	Jun-28	Sep-28	Mar-27	Jun-28	Sep-28
J3C	Dec-26	Jun-29	Jun-29	Dec-26	Jun-29	Jun-29
Cygnus	Dec-30	Sep-32	Sep-34	Jun-31	Mar-33	Sep-35
Clipper South	Mar-29	Sep-30	Jun-32	Mar-29	Sep-30	Jun-32
Galleon	Sep-30	Dec-36	Dec-36	Sep-30	Dec-36	Dec-36
Eris	-	-	-	-	-	-

Notes:

1. The CoP date used to estimate Reserves is defined as (a) the end of the last three month period that the maximum cumulative operating cash flow occurs; (b) the end of the technical field life; or (c) the end of the licence period, whichever is projected to occur the soonest.
2. The GLA CoP is latest in the 1P case and earliest in the 3P case. This outcome is caused by the use of single, deterministic forecasts for both the host baseline profile compensation and Victory production. In the 1P GLA scenario, GLA pays the least OPEX share and receives the most compensation, resulting in the later CoP. Conversely, in the 3P scenario, GLA pays the most OPEX share and receives the least compensation.
3. The CoP dates for the Clipper South and Galleon Fields are linked to the CoP date of the host facility (the Clipper Field). However, no information has been provided on the expected CoP date of the Clipper Field and, as such, the CoP dates for the Clipper South and Galleon Fields have been calculated independently.

Sproule ERCE has calculated before tax net present values (“NPV”) at a 10% discount factor for all assets, as displayed in Table 1.7. Sproule ERCE has also calculated before tax NPVs for each asset at discount factors of 0%, 5%, 10%, 15% and 20%. These tables are presented in Section 11.4 and reflect the total Reserves (i.e. Developed plus Undeveloped).

Table 1.7: Asset level before tax NPV of the total Reserves

(attributable to Serica as at 30 June 2026)

Asset	Before tax NPV at 10% discount rate (US\$MM)		
	1P	2P	3P
GLA	-60	-76	-96
Catcher	-11	18	41
GEAD	-26	-15	2
Chiswick	32	54	67
Grove	4	10	18
Kew	3	6	7
J3C	0	0	0
Cygnus	69	151	245
Clipper South	8	18	28
Galleon	0	8	14
Eris	0	0	0
Total	19	173	327

Notes:

1. Individual values may not add up to the reported totals due to rounding.

Sproule ERCE has calculated before and after tax NPVs at the corporate entity level at discount factors of 0%, 5%, 10%, 15% and 20%; these are presented in Table 1.8. The after tax NPVs take into account Serica's historical tax attributes in each corporate entity, which were provided by Serica.

Table 1.8: Corporate entity level before and after tax NPV of the total Reserves

(attributable to Serica as at 30 June 2026)

Corporate Entity	Scenario	Before tax NPV (US\$MM) at discount rates of:					After tax NPV (US\$MM) at discount rates of:				
		0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Hurricane Whirlwind	1P	39	54	63	68	71	51	59	64	67	68
	2P	137	143	144	141	137	139	139	135	130	124
	3P	259	250	235	220	206	202	192	181	171	160
Prax Hurricane GLA	1P	-213	-137	-84	-46	-18	-248	-174	-122	-84	-57
	2P	-188	-110	-57	-20	6	-232	-156	-103	-66	-39
	3P	-148	-78	-31	0	22	-200	-130	-82	-50	-27
Prax Hurricane GWA	1P	23	34	41	46	49	11	18	23	26	28
	2P	74	84	88	90	90	59	64	65	65	64
	3P	125	126	125	123	120	101	98	94	91	88
Prax Upstream	1P	-5	-3	-2	-1	0	-6	-4	-3	-2	-1
	2P	-5	-3	-2	-1	0	-6	-4	-3	-2	-2
	3P	-5	-3	-2	-2	-1	-6	-4	-3	-3	-2
Spirit NL	1P	0	0	0	0	0	0	0	0	0	0
	2P	0	0	0	0	0	0	0	0	0	0
	3P	1	1	0	0	0	0	0	0	0	0
Total	1P	-156	-52	19	68	102	-193	-101	-37	7	38
	2P	18	114	173	210	232	-40	43	94	127	148
	3P	231	295	327	343	348	97	156	190	209	219

Notes:

1. Individual values may not add up to the reported totals due to rounding.

1.3 Contingent Resources

Under PRMS, 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 due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no 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 categorised in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.

In addition to quantities that are classified by Sproule ERCE as Reserves, the assets include quantities that have been classified by Sproule ERCE as Contingent Resources.

The projects associated with Contingent Resources are, by definition, commercially less mature than the Reserves projects. Summaries of the oil, gas and oil equivalent Contingent Resources are presented in Table 1.9, Table 1.10 and Table 1.11, respectively, by PRMS sub-maturity class.

Sproule ERCE has been guided by Serica on which Contingent Resources projects have been included in its independent evaluation. No economic analyses have been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 1.9: Oil Contingent Resources as at 30 June 2026

Asset	Project	Gross on Licence (MMstb)			Company Working Interest (MMstb)			PRMS Sub-Class
		1C	2C	3C	1C	2C	3C	
GLA	ERSS	0.7	1.1	1.9	0.3	0.4	0.8	DP
	Tormore Infill	0.5	0.9	1.6	0.2	0.3	0.6	DP
	SGP Life Extension	-	0.1	0.5	-	0.1	0.2	DP
Catcher	Varadero West	0.9	2.1	4.1	0.1	0.2	0.4	DP
	Burgman North	-	0.7	2.1	-	0.1	0.2	DOH
	CP4 WSO	0.1	0.4	1.1	0.0	0.0	0.1	DOH
	Organic Oil Recovery	0.3	0.7	1.6	0.0	0.1	0.2	DP
GEAD	DIH	0.2	0.9	3.3	0.0	0.0	0.2	DP
	G15a Conversion	0.2	0.9	2.4	0.0	0.0	0.1	DP
Grove	Grove East Infill	0.0	0.1	0.1	0.0	0.1	0.1	DP
Cygnus	Well 16	0.0	0.1	0.1	0.0	0.0	0.0	DP
Clipper South	NW Infill	0.0	0.0	0.0	0.0	0.0	0.0	DP
Eris	NFA Production	-	-	-	-	-	-	DP
	Total	3.1	8.1	18.9	0.7	1.4	2.9	

Table 1.10: Gas Contingent Resources as at 30 June 2026

Asset	Project	Gross on Licence (Bscf)			Company Working Interest (Bscf)			PRMS Sub-Class
		1C	2C	3C	1C	2C	3C	
GLA	ERSS	26.2	42.3	71.7	10.5	16.9	28.7	DP
	Tormore Infill	11.2	19.4	33.3	4.5	7.8	13.3	DP
	SGP Life Extension	-	18.7	53.9	-	7.5	21.6	DP
Catcher	Varadero West	0.0	0.5	1.0	0.0	0.0	0.1	DP
	Burgman North	-	0.3	0.8	-	0.0	0.1	DOH
	CP4 WSO	0.1	0.2	0.6	0.0	0.0	0.1	DOH
	Organic Oil Recovery	0.1	0.3	0.7	0.0	0.0	0.1	DP
GEAD	DIH	-	-	-	-	-	-	DP
	G15a Conversion	-	-	-	-	-	-	DP
Grove	Grove East Infill	3.8	8.4	15.9	3.5	7.8	14.7	DP
Cygnus	Well 16	11.5	25.1	46.0	1.7	3.8	6.9	DP
Clipper South	NW Infill	19.0	31.0	50.6	4.8	7.8	12.6	DP
Eris	NFA Production	1.6	2.5	3.5	0.9	1.4	1.9	DP
	Total	73.6	148.7	278.0	25.9	53.0	100.1	DP

Table 1.11: Oil Equivalent Contingent Resources as at 30 June 2026

Asset	Project	Gross on Licence (MMboe)			Company Working Interest (MMboe)			PRMS Sub-Class
		1C	2C	3C	1C	2C	3C	
GLA	ERSS	5.2	8.4	14.3	2.1	3.4	5.7	DP
	Tormore Infill	2.5	4.2	7.3	1.0	1.7	2.9	DP
	SGP Life Extension	-	3.4	9.8	-	1.3	3.9	DP
Catcher	Varadero West	1.0	2.2	4.3	0.1	0.2	0.4	DP
	Burgman North	-	0.8	2.2	-	0.1	0.2	DOH
	CP4 WSO	0.1	0.5	1.2	0.0	0.0	0.1	DOH
	Organic Oil Recovery	0.4	0.8	1.7	0.0	0.1	0.2	DP
GEAD	DIH	0.2	0.9	3.3	0.0	0.0	0.2	DP
	G15a Conversion	0.2	0.9	2.4	0.0	0.0	0.1	DP
Grove	Grove East Infill	0.7	1.5	2.9	0.6	1.4	2.7	DP
Cygnus	Well 16	2.0	4.4	8.1	0.3	0.7	1.2	DP
Clipper South	NW Infill	3.3	5.4	8.8	0.8	1.3	2.2	DP
Eris	NFA Production	0.3	0.4	0.6	0.2	0.2	0.3	DP
	Total	15.8	33.8	66.9	5.2	10.6	20.2	DP

Notes to Tables 1-9 to 1-11:

1. Development Pending (DP), Development On Hold (DOH), Development Unclassified (DUC) and Development Not Viable (DNV).
2. Conversion of gas to boe equivalent is based on 5.8 Mscf/boe.
3. Company Working Interest Contingent Resources are based on their working interest share of the Gross Contingent Resources. Net Entitlement Contingent Resources are not reported, but these would be equal to Company Working Interest as there are no royalties to be deducted.
4. Gas Contingent Resources are based on wellhead volumes prior to shrinkage.
5. These are unrisks Contingent Resources that have not been risks for Chance of Development.
6. The estimates presented are based on aggregating individual projects with different levels of risk and as such should be used with caution.
7. Individual values may not add up to the reported totals due to rounding.

2. Introduction

Serica Energy plc completed its acquisition of TotalEnergies interest in the GLA on 26 March 2026 and its acquisition of ONE Dyas' interests in the Catcher Area and GEAD on 11 June 2026. Serica Energy plc has also acquired petroleum interests in certain assets located in the UK North Sea from Spirit Energy, with the transaction completed on 1 October 2026. The assets lie in three broad areas (Figure 2.1): in the West of Shetland region of the UKCS (GLA fields), in the Central North Sea (Catcher Area and GEAD) and in the Southern North Sea area (GMA, Clipper South, Cygnus, Galleon and Eris fields).

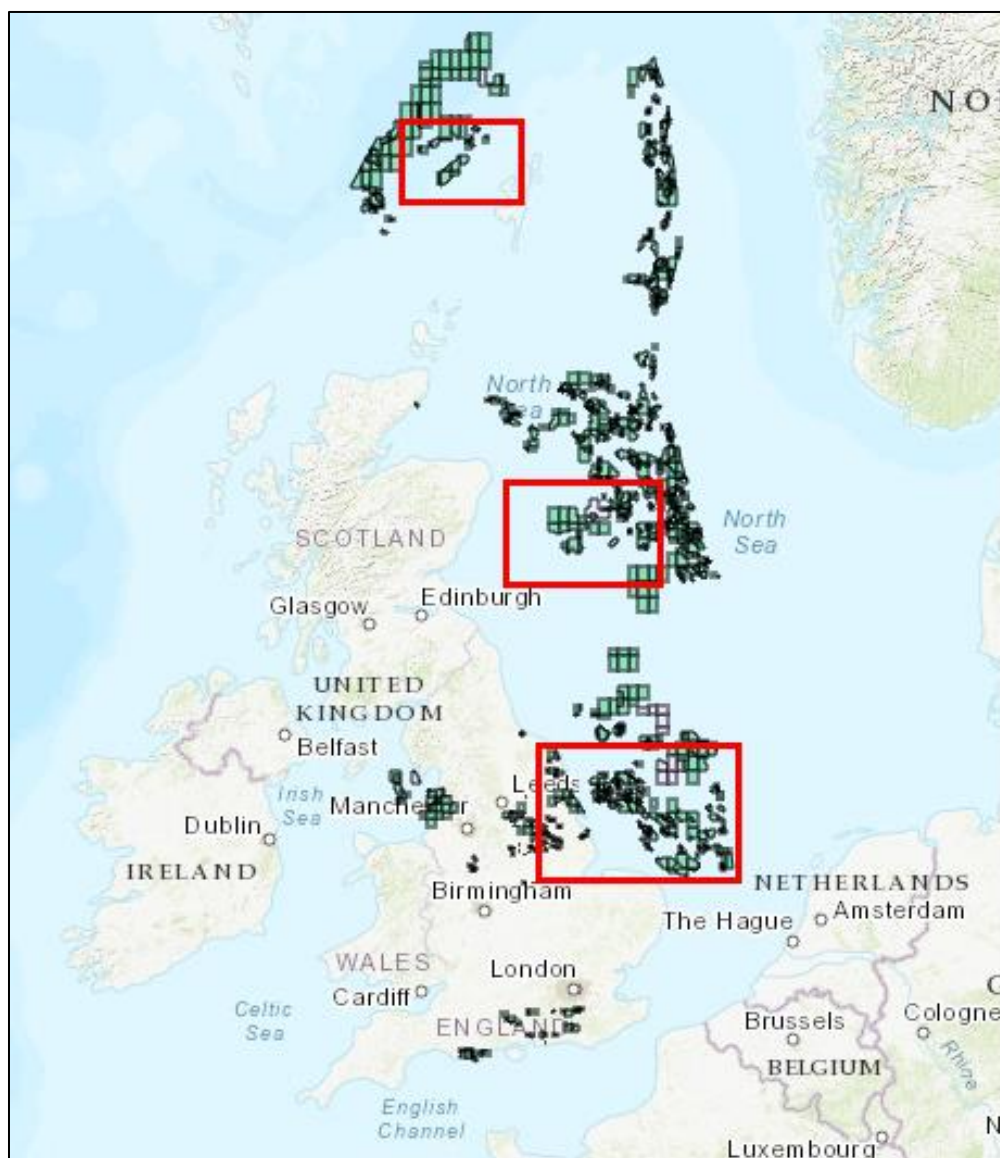


Figure 2.1: Asset areas of interest

Source: Sproule ERCE

Sproule ERCE has been commissioned by Serica to evaluate the aforementioned assets and determine the Reserves (1P, 2P, and 3P), the associated before and after tax net present value and the Contingent Resources (1C, 2C and 3C) attributable to certain projects. Sproule ERCE was also asked to review costs, i.e. Operational Expenditure (“OPEX”), Capital Expenditure (“CAPEX”), and Abandonment Expenditure (“ABEX”) and carry out discounted cashflow analysis to confirm the economic limit, or CoP dates, and commerciality for Reserves.

The Company Working Interest and Net Entitlement Reserves volumes presented in this report represent the volumes associated with Serica’s.

2.1 Data Provided

Various data pertinent to the evaluation were obtained from the Company and public data sources, and are summarised below:

1. Seismic interpretations and reports;
2. Drilling reports;
3. Log data (image and/or Log ASCII format (“LAS”));
4. Petrophysical reports;
5. Static geological models;
6. Technical study reports;
7. Wellbore schematics;
8. Pressure data (static gradients, build-ups, flowing);
9. Reservoir temperature data;
10. Fluid analyses (oil, water, gas);
11. Production data (oil, water, gas);
12. Reservoir simulation model(s);
13. Infrastructure maps;
14. Partner meeting material (technical, operating and subsurface committee meetings (“TCM”, “OCM” and “SSCM”));
15. Actual capital cost data for drilling, completing, equipping and tying-in (approval for expenditure “AFE”s);
16. Abandonment, decommissioning and reclamation costs;
17. Life of field projections;
18. Accounting data (lease operating statements, revenue statements);
19. Petroleum product contract information;
20. Corporate economic model.

2.2 Work Completed

Sproule ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. Sproule ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place. Estimates of recovery factors were prepared based on consideration of the results of production performance analysis, reservoir simulation models, classical reservoir engineering calculations and the performances of analogue fields.

For the evaluation of the resources, Sproule ERCE has used the PRMS definitions of “Estimated Ultimate Recovery” and “Technically Recoverable Resources” (“EUR” and “TRR”, respectively), for which the definitions can be found in Appendix 2. In this Report, the term EUR refers to “Technical EUR” or “EUR_{tech}” in accordance with the Guidelines for Application of the Petroleum Resources Management System, revised in July 2022.

Production profiles have been generated by Sproule ERCE for the Reserves. The forecasts generated for Reserves have then been used as input to an economic model to undertake an Economic Limit Test (“ELT”) and assess commerciality. The economic model has been provided to Sproule ERCE by Serica and has been reviewed by Sproule ERCE to confirm that the terms of the fiscal regime are correctly represented. Sproule ERCE has also derived independent estimates of Contingent Resources.

Sproule ERCE has evaluated the development plans for the various assets. For each field, Sproule ERCE has reviewed forecasts of capital, operating and abandonment costs provided by the Serica. The costs provided were reviewed and benchmarked against Sproule ERCE’s internal database to ensure they are reasonable. Where possible, these estimates were compared to historical, actual costs. Sproule ERCE has used its own cost estimates where these differ significantly from those presented. The economic analysis does not take into account any outstanding debt, nor future indirect corporate costs.

Sproule ERCE has also included, in its Reserves assessment, carbon pricing, a mechanism which captures the external costs of greenhouse gas (“GHG”) emissions and ties them to their sources (hydrocarbon assets) through a price. In the UK, oil and gas fields are subject to a carbon price through an emissions trading system (“ETS”), namely the UK Emissions Trading System (“UK-ETS”). These costs are included, under PRMS, in the evaluation of projects’ economics and commerciality.

For the assets evaluated, Sproule ERCE has verified the inclusion of ETS in the future cost projections or budgets prepared by the Operators. Where ETS were found to be missing, Sproule ERCE has prepared forecast emission profiles, based on available Operator budget data and other relevant operational information, for the volumes of CO₂ equivalent expected to arise during hydrocarbon production operations and falling within the scope of the UK ETS. The associated future costs have been estimated by applying Sproule ERCE’s forecast UK carbon allowance (“UKA”) price deck to the relevant

emissions profiles. Throughout the report, these costs are either presented explicitly as ETS costs or incorporated within the applicable OPEX estimates.

3. Greater Laggan Area

The GLA fields are located between 75 km and 125 km north-west of the Shetland Islands on the UKCS. The cluster comprises four producing gas-condensate fields: Laggan; Tormore; Edradour; and Glenlivet. The fields have been developed through a dedicated subsea pipeline infrastructure to the SGP, approximately 1 km to the north of the SVT. The gas is exported via the SIRGE pipeline and the FUKA pipeline to St Fergus where NGLs are extracted, while the condensate is exported to the SVT. The fields are operated by Serica.

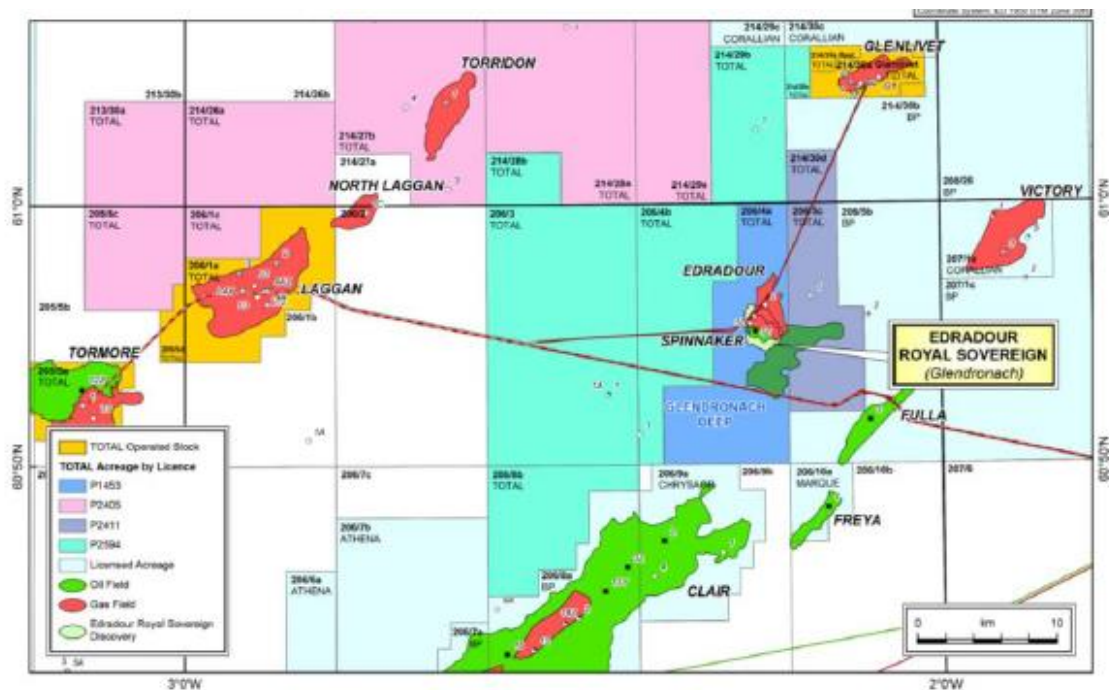


Figure 3.1: GLA fields location map

Source: Operator

Production from the area commenced in 2016 from the Laggan and Tormore Fields. Glenlivet and Edradour were developed in 2017 and came onstream in the second half of 2017. An infill well was drilled in Laggan and brought onstream in 2019. The area production peaked at over 500 MMscf/d wet gas in 2016 and is continuing to decline (Figure 3.2). A LP compression project was executed in 2022-2023.

Prior to the Victory Field, a third-party new development which came on stream in September 2025, the fields were, in aggregate, producing at a combined gas rate of approximately 79 MMscf/d (Figure 3.2).

Victory production is tied into one of the two GLA subsea flowlines that transport fluids onshore to SGP. All GLA wells have been re-routed to the other flowline. Arrival pressures at SGP have also been increased to reduce Victory gas velocity. The impact of these changes is to back-out some GLA production; the average gas rate from GLA in June 2026 was 32 MMscf/d (Figure 3.3). Under current

operations, the two Glenlivet wells have shown the most stable flow and the Laggan and Tormore wells flow intermittently.

To account for the back-out of GLA production, a compensation mechanism has been agreed between the GLA and Victory partners. Under this mechanism, GLA partners will be compensated up to an agreed Host Baseline Profile (“HBP”) which reflects GLA performance “as if Victory had not been developed”.

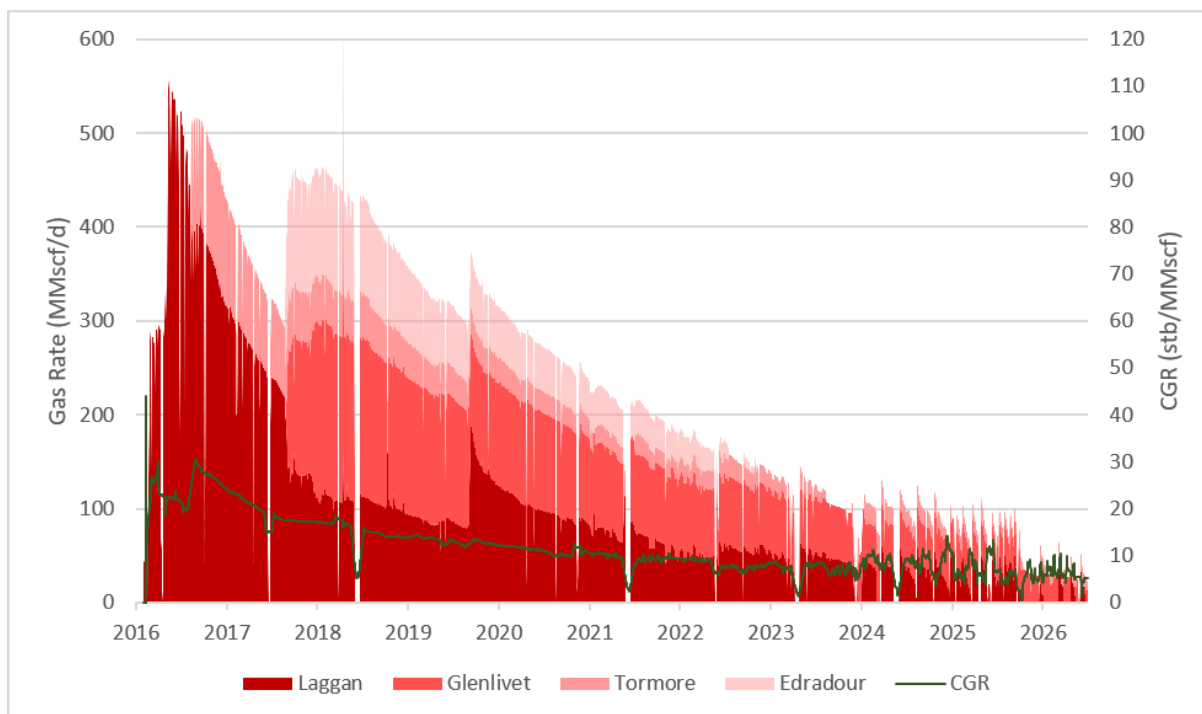


Figure 3.2: GLA hub wet gas production and CGR history

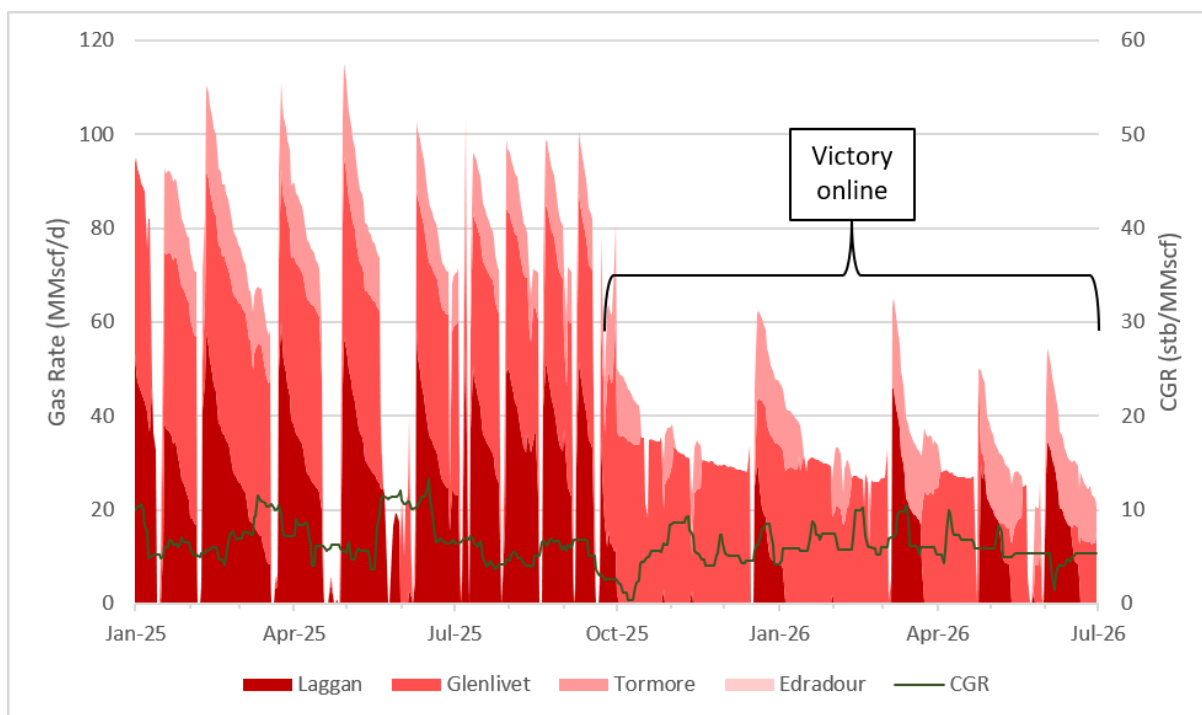


Figure 3.3: GLA hub wet gas production and CGR history, 2025+

Laggan Field

The Laggan Field is located in approximately 600 m water depth, 125 km north-west of the Shetland Islands on the UKCS. The field lies in Blocks 206/1a and 205/5d, part of the P911 and P1159 licences.

The field was discovered by Shell in 1986 after Well 206/1-2 encountered a 34 m column of gas. TOTAL acquired the licence in 1995 and gained approval of a field development plan in 2010.

The structure of the field is a NE-SW striking anticline with dip closure to the north-west, structural closure in the south-east and a stratigraphic pinch out to both the north-east and south-west (Figure 3.4). Gas is found within the Palaeocene Vaila Formation, a sand-rich turbidite sequence. The reservoir package is subdivided into three main sand bodies, A, B and C, interbedded with two field-wide shales. The reservoir quality of the sand bodies is good, with porosity ranging from 20% to 25%, and net to gross ratio (“NTG”) in the range of 85% to 95%.

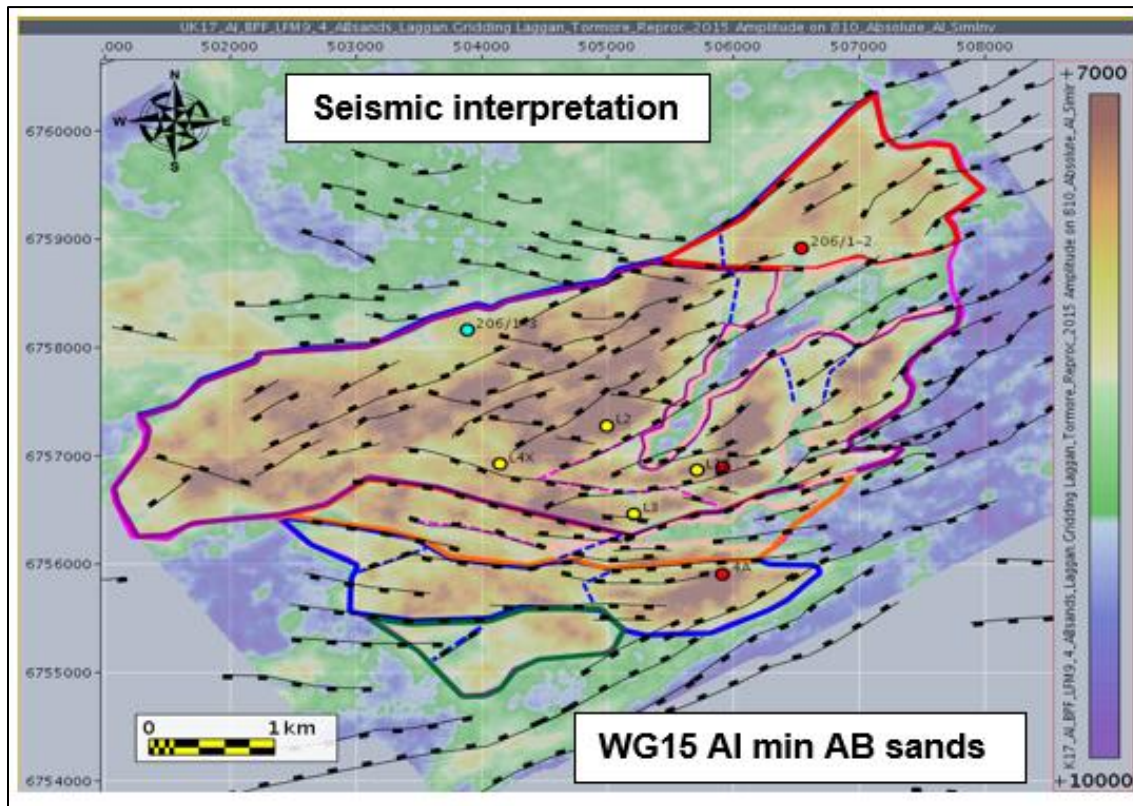


Figure 3.4: Laggan Field amplitude extent and mapped faults

Source: Operator

First gas was in Q1 2016 via an initial four-well development. The fifth development well (Well L5) was drilled and brought onstream in 2019, and shortly after another well, Well L3, started producing cyclically. Production from the Laggan Field has been adversely impacted by the Victory tie-back, with Laggan wells only available for short flow periods following shut-ins. Cumulative gas production up to 30 June 2026 was 379 Bscf.

Tormore Field

The Tormore Field is located in approximately 600 m water depth, 125 km north-west of the Shetland Islands on the UKCS and in Blocks 205/5a and 205/4b. The field was discovered in 2007 and consists of turbidite sandstones belonging to the Vaila Formation. Four main reservoir sands are present within Tormore; the Z sand overlying the deeper A, B and C sands. The Z sand is well developed in Well 205/5a-T2Z but poorly developed in Well 205/5a-1 (Figure 3.5). Most of the Z sand is interpreted as oil-bearing, whereas the A, B and C sands are both gas and oil-bearing. The reservoirs exhibit high NTG, averaging

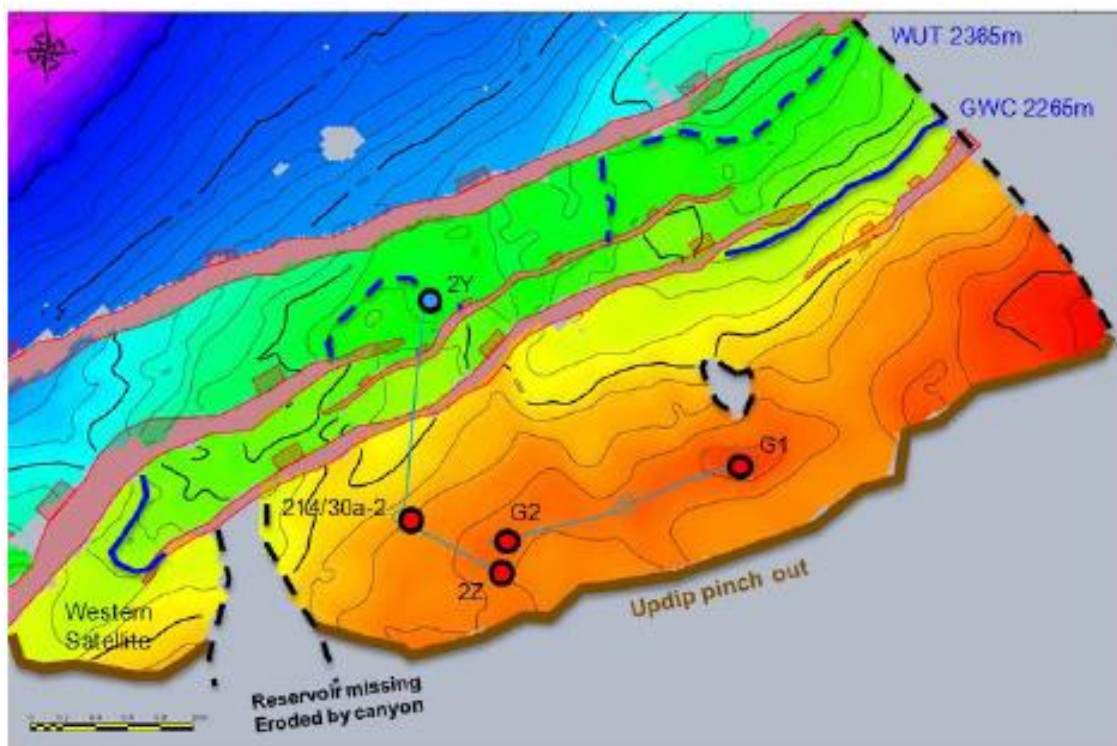


Figure 3.6: Glenlivet Field top structure map

Source: Operator

First gas was achieved in August 2017. Glenlivet is developed with two wells and they are the only wells in the GLA that are able to flow in a stable manner following the Victory tie-in. As at 30 June 2026, the cumulative wet gas production is 256 Bscf.

Edradour Field

The Edradour Field is located in approximately 300 m water depth, 36 km north-east of the Laggan field in Block 206/4a. The field was discovered in 2011 after Well 206/4-2 encountered a 43 m thick gas column in the Black Sail sandstones and pressure data suggest the presence of an oil rim below the gas column. The field is a combined structural and stratigraphic trap, with four regions defined by interpreted faults (Figure 3.7).

The reservoir in Edradour comprises Early Cretaceous Black Sail sandstones. The Black Sail and Spinnaker sands encountered in Well 206/4-2 are part of the Commodore Formation, which thins to the south-west over the field. The reservoirs are characterised by high NTG (90%) and moderate porosity (~15%).

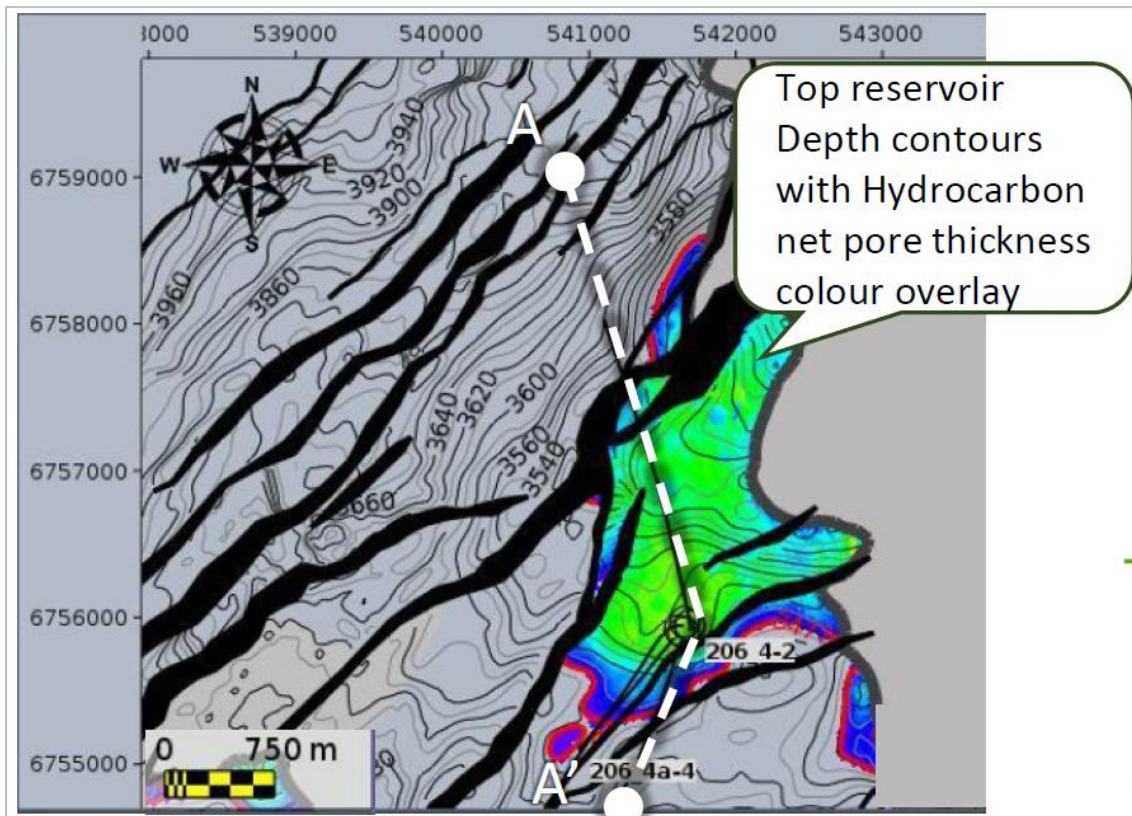


Figure 3.7: Edradour Field depth structure map

Source: Operator

First gas was achieved in August 2017. During late 2022, the only development well, Well E1, ceased production due to liquid loading with production of both formation oil and water, appearing to confirm the presence of an interpreted oil rim from pressure data. The cumulative wet gas production up to the shut-in was 106 Bscf.

3.1 Development Plans

There are no firm plans to drill further wells in the GLA Fields. Less mature development opportunities exist in the ERSS and in the Tormore Fields which are currently under evaluation by the Operator, alongside an opportunity to tie-back a future third party development to the GLA facilities. These opportunities are discussed in Section 3.5

3.2 Estimated Ultimate Recovery

The fields that comprise the GLA are all in late life and have well established production trends. Sproule ERCE's production forecasts are based on decline curve analysis ("DCA"), with sets of forecasts derived for two scenarios: "pre-Victory" and "post-Victory".

The "pre-Victory" forecasts were derived on a well-by-well basis, using data up to the end of August 2025 and individual well cut-off rates between 2.5 and 5 MMscf/d. These forecasts are used to estimate the TRR of the GLA assets should Victory have not been brought onstream.

The "post-Victory" forecasts were derived at the GLA hub level, using data up to the end of June 2026 and a technical cut-off rate of 10 MMscf/d. These forecasts are set to deliver the same TRR as the pre-Victory forecasts, assuming the Victory back-out effect constitutes pure production deferral for the GLA assets. It is these "post-Victory" forecasts that are used as the basis for Reserves (see Section 3.4).

A summary of Sproule ERCE's EUR estimates and the inferred best case recovery factors are presented in Table 3.1. The EUR estimates are to technical cut-off (i.e. minimum flow rate) and not limited by any date.

Table 3.1: GLA EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Laggan	Gas	541	379	70%	397	411	423	76%
Tormore	Gas	272	104	38%	108	109	111	40%
Edradour	Gas	145	106	73%	106	106	106	73%
Glenlivet	Gas	338	256	76%	270	275	282	81%

Notes:

1. Recovery factors are calculated using the Operator's Petroleum Initially in Place ("PIIP") best estimates derived volumetrically or from material balance methods.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts (Table 3.2). Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. Different production efficiencies are applied in the "pre-" and "post-" Victory scenarios.

Prior to the Victory tie-in, regular pigging and line sweeping was required to maintain GLA production. So far in 2026 there has been significantly less requirement for pigging and line sweeping than expected and this has been taken into account in the production efficiency forecast for the "with Victory" scenario.

In both scenarios, planned downtime includes a 29-day shutdown every three years from 2027, this is to align with shutdowns at SIRGE/FUKA/St. Fergus.

Table 3.2: GLA production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
GLA pre-Victory	88.1	81.2	88.1	88.1	81.2	88.1	88.1
GLA post-Victory	92.7	85.9	92.7	92.7	85.9	92.7	92.7

The gross sales gas production forecasts for the GLA hub, together with production history since 2022 are presented in Figure 3.8.

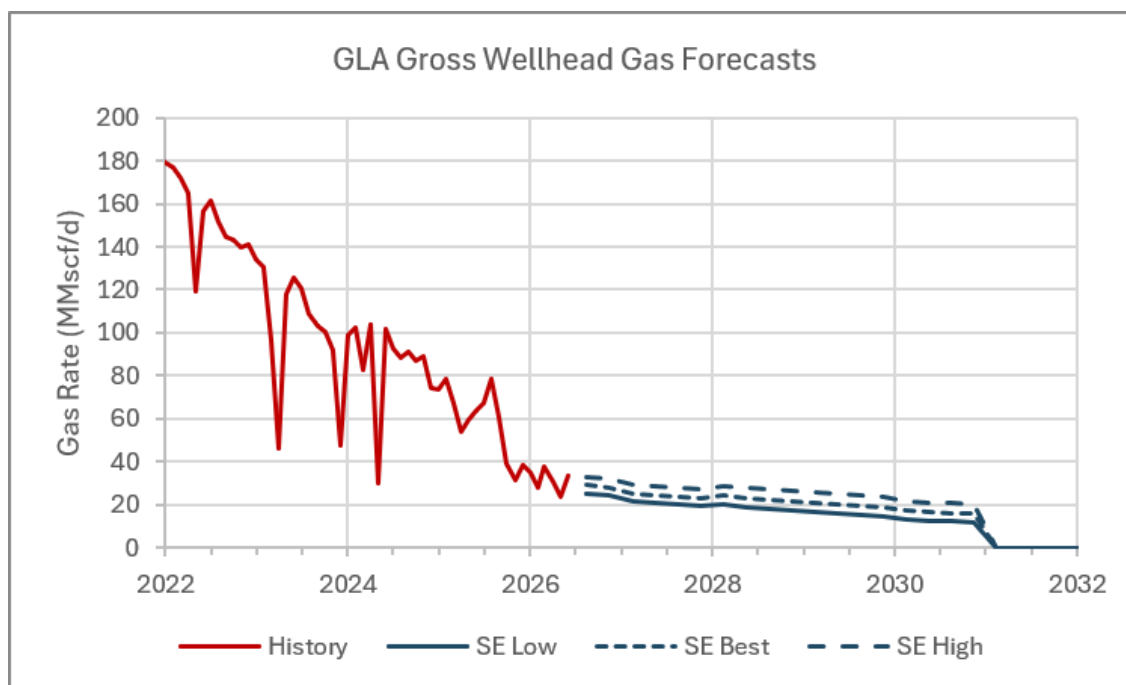


Figure 3.8: GLA gross wellhead gas production forecasts

SE = Sproule ERCE

3.3 Facilities and Cost

Each of the GLA fields are produced via subsea infrastructure, tied back to the onshore SGP.

The Laggan field infrastructure includes five subsea wells, drilled from a central manifold. The gas produced from the development wells is transported through a twin pipeline to the SGP for processing and onward shipment.

The Tormore Field is developed with a single production well tied into a subsea manifold, connected to the twin export pipeline from Laggan to the SGP.

The Glenlivet Field is developed with two production wells tied into a subsea manifold. Production is exported through a 35 km pipeline to the Edradour pipeline entry manifold where it joins the Tormore/Laggan twin pipelines to the SGP.

The Edradour Field was developed via a single production well tied back to a subsea manifold; the field has been shut-in since late 2022. The manifold is connected via a spare line to the main Laggan twin pipeline to the SGP.

Sproule ERCE has reviewed the Operator's latest work programmes and budgets ("WP&B"s), together with the TCMs, OCMs, and life-of-field cost estimates provided by Serica. Sproule ERCE considers the CAPEX presented by the Operator to be reasonable. The majority of the remaining 2026 CAPEX relates to SGP operations, including vessel insulation upgrades, SGP MEG management, and other minor facilities-related projects.

The Operator's OPEX comprises fixed/routine OPEX, tariff, and OPEX-sharing elements. Sproule ERCE considers the overall OPEX presented by the Operator to be reasonable based on historical actuals. Sproule ERCE has adopted a flat fixed routine OPEX assumption in real terms through field life, with the exception of certain non-routine expenditures in 2026. Sproule ERCE has also reviewed and broadly adopted the Operator's tariff assumptions based on the latest WP&B estimates. While the Operator's WP&B does not include the SIRGE pipeline tariff, Sproule ERCE has included this within its forecasts.

The SGP OPEX share has been allocated based on the contract terms, using third-party Victory production profiles together with Sproule ERCE's forecasts of backed out GLA production.

Based on guidance by Serica, Sproule ERCE has treated the HBP compensation mechanism as an additional OPEX line item. When Sproule ERCE's export gas forecasts are less than the HBP, compensation is owed from Victory to GLA and vice versa. Compensation is calculated by applying Sproule ERCE's NBP gas price and Brent crude oil price forecasts to the respective gas and oil production "wedges" between Sproule ERCE's export forecasts and the HBP.

Sproule ERCE estimates ABEX of approximately GBP499 MM, including the plugging and abandonment of wells, decommissioning of subsea infrastructure and associated facilities, and the decommissioning of the SGP terminal.

Sproule ERCE's forecasts of production, CAPEX, OPEX and ABEX are presented in Appendix 1, with all costs stated in 2026 real terms.

3.4 Reserves

Based on instruction by Serica, only the physical production from the GLA assets is considered for Reserves; compensation received from Victory is excluded from the Reserves.

Sproule ERCE's GLA wellhead gas forecasts are converted to SGP export gas forecasts by deducting GLA's share of fuel and flare (Victory is forecast to contribute over 80% of fuel and flare). To convert from SGP export gas to sales gas, a 9% shrinkage is applied that arises from removal of NGLs at St Fergus.

Wellhead (and sales) condensate forecasts are calculated by applying an average CGR of 9.2 stb/MMscf to the wellhead gas forecasts; this being the average GLA CGR post-Victory. NGL forecasts are calculated by applying a yield of 16.5 bbl/MMscf to the SGP export gas forecasts (i.e. wellhead minus fuel and flare).

The sales forecasts used as input to the economic model are terminated at end-2030 based on Serica's estimate of CoP of the Victory field and the assumption that, at such event, all production through the SGP would stop in the absence of additional projects.

A summary of the gross Reserves at the hub level is presented in Table 3.3 together with appropriate CoP dates.

Table 3.3: GLA gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
GLA	Developed	0.7	0.8	0.8	25.3	28.7	29.0
	Undeveloped	-	-	-	-	-	-
	Total (Dvdp+Undvdp)	0.7	0.8	0.8	25.3	28.7	29.0
	COP (Total)	Dec-30	Jun-30	Sep-29	Dec-30	Jun-30	Sep-29

Notes:

1. The GLA CoP is latest in the 1P case and earliest in the 3P case. This outcome is caused by the use of single, deterministic forecasts for both the host baseline profile compensation and Victory production. In the 1P GLA scenario, GLA pays the least OPEX share and receives the most compensation, resulting in the later CoP. Conversely, in the 3P scenario, GLA pays the most OPEX share and receives the least compensation.

3.5 Contingent Resources

Sproule ERCE has assigned Contingent Resources to three projects evaluated by the Operator.

ERSS Discovery

The first project relates to the ERSS gas condensate discovery, lying in water depth of 295 metres and a reservoir depth of 3,650 m TVDSS. The discovery was made by Well 206/4a-4 ("GD-01"), drilled in

2018, which penetrated gas bearing sands in the Lower Cretaceous aged Royal Sovereign (primary reservoir) and the Palaeocene aged Spinnaker (secondary reservoir) formations (Figure 3.9).

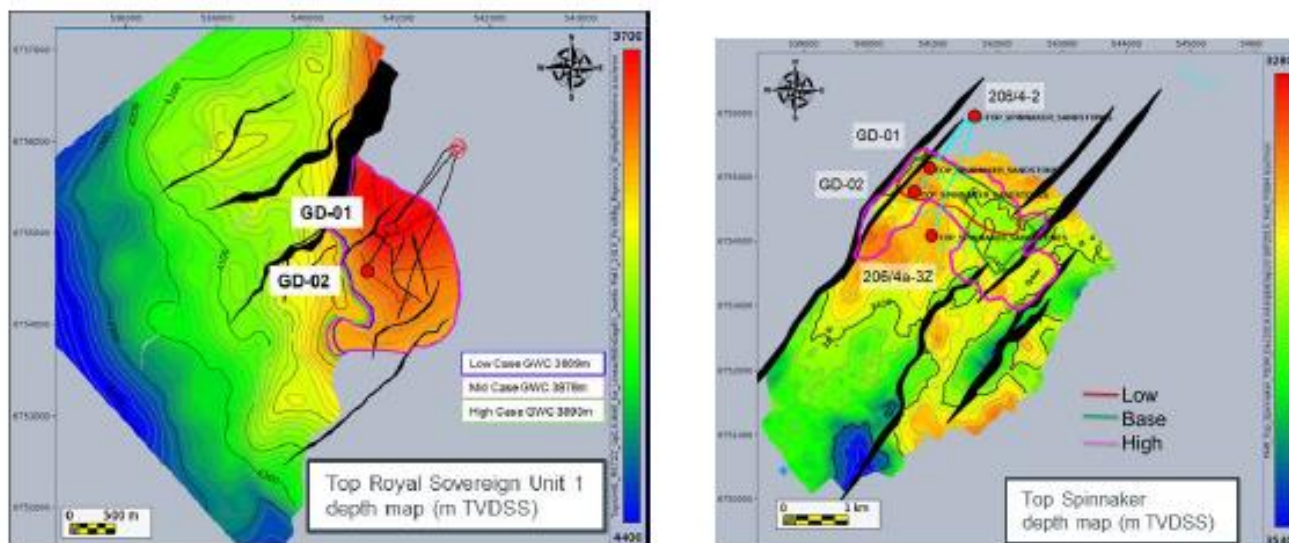


Figure 3.9: ERSS discovery top structure map of primary and secondary targets

Source: Operator

Well GD-01 was tested across the Royal Sovereign reservoirs at gas rates up to 40 MMscf/d, with two main sand units contributing the majority of production. The produced gas on test was relatively dry with a CGR of ~5 stb/MMscf. An appraisal well, Well 206/4a-5z (“GD-02”), was drilled in 2020 and encountered a thicker, more interbedded interval of the Royal Sovereign reservoir (although with marginally higher reservoir pressure). Well GD-02 also encountered the Spinnaker formation but found it to be more interbedded than at Well GD-01.

The development concept comprises a sidetrack of existing Well GD-01 and installation of a dual completion to develop the Royal Sovereign and Spinnaker reservoirs. The well would be a subsea tieback to the Edradour manifold with production evacuated via the existing GLA pipeline network. Due to the high reservoir pressure in ERSS, a high integrity pressure protection system (“HIPPS”) has previously been considered. Sproule ERCE understands that recent studies suggest that the HIPPS is no longer required and more extensive intelligent pigging of the pipeline is sufficient to overcome the issue. Development of the ERSS discovery would also require installation of a mercury removal unit (“MRU”) at SGP due to the mercury content of the gas (recorded up to 300 µg/sm³ on well test).

Sproule ERCE’s estimates of Contingent Resources are based on deterministic independent volumetrics and recovery factors. In the Royal Sovereign reservoir, the low case area is limited to an amplitude response around Well GD-01 and assumes separation from Well GD-02; the high case assumes the full area is connected. A similar approach is taken for the Spinnaker reservoir, although both wells are

included in the low case area. The range between the low and high case areas is dictated by confidence in the lateral extent of the amplitude response seen around the wells. A recovery factor range of 60 – 70 – 80% is applied to the aggregated Royal Sovereign and Spinnaker gas in place estimates to determine the gas TRR.

The ERSS development is currently undergoing a re-framing exercise with a Field Development Plan Addendum update planned to be submitted in October 2026 ahead of a final investment decision (“FID”) scheduled later in Q4 2026 and first gas potentially scheduled in 2029. Various technical and Front End Engineering Design (“FEED”) studies are ongoing with focus on flow assurance and required modifications at the SGP, including appropriate MRU solutions.

Tormore Infill

Sproule ERCE has assigned Contingent Resources to an infill well project in the Tormore Field. Existing Well T-3 produces from the A, B and C sands and has a connected gas in place, inferred by p/Z analysis, less than the volumetric gas in place estimates for field. The planned infill well targets an area of the field thought to be undrained by the existing well.

Separate locations are under evaluation by the Operator but the most promising location is thought to be the “Tongue” target, located north of Well T3 and separated from Well T3 by an east-west trending fault. This area has a seismic response that is suggestive of sand presence and the recent 4D seismic survey suggests the area may not have been depleted.

Sproule ERCE’s estimates of Contingent Resources are based on deterministic independent volumetrics and recovery factors. The low case is limited to an area with the strongest response on the seismic sand probability volume, and is limited to the west by a possible fault. The high case includes the full fault panel and is extended to the west up to the hardening response on the 4D seismic data, which may represent an oil-replacing-gas effect. A recovery factor range of 80 – 85 – 90% is applied based on performance of Well T-3 relative to its connected gas in place estimated by p/Z analysis.

The project is currently under evaluation by the Operator with subsurface studies progressing towards internal review gates in Q3 2026.

*Tormore Amplitude Response
with Low Case Polygon Extent*

*Tormore Amplitude Response
with High Case Polygon Extent*

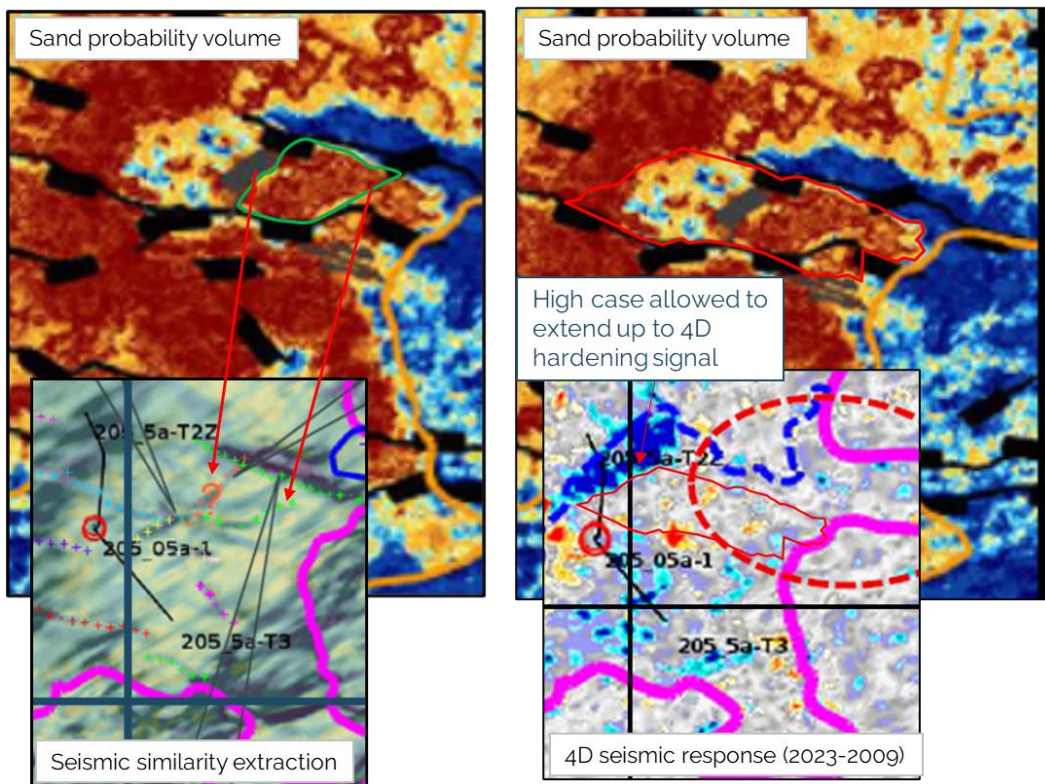


Figure 3.10: Assessed Tormore infill location with Sproule ERCE low and high case areas

Source: Operator

SGP Life Extension

Contingent Resources are also attributed to the extension of the economic life of the SGP as a result of the execution of additional future projects (i.e. the ERSS discovery, Tormore infill well and proposed third-party tieback of the Tornado discovery). Sproule ERCE has assumed these projects would sufficiently extend the GLA CoP to enable production of the remaining TRR beyond the currently estimated GLA Reserves CoP dates.

A summary of gross Contingent Resources attributed to the GLA fields is provided in Table 3.4. Note that these volumes relate only to the extension of the Reserves case (i.e. existing GLA production) and do not include any extension of other Contingent Resources projects.

Table 3.4: GLA gross Contingent Resources

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
ERSS	0.7	1.1	1.9	26.2	42.3	71.7	DP
Tormore Infill	0.5	0.9	1.6	11.2	19.4	33.3	DP
SGP Life Extension	-	0.1	0.5	-	18.7	53.9	DP

4. Catcher Area

The Catcher, Varadero and Burgman Fields (collectively the Catcher Area) lie within Licence P1430 (Block 28/9a) and were discovered in 2010. The licence is situated to the west of the Central Graben within the UKCS (Figure 4.1) around 170 km southeast of Aberdeen. Water depths are less than 100 m.

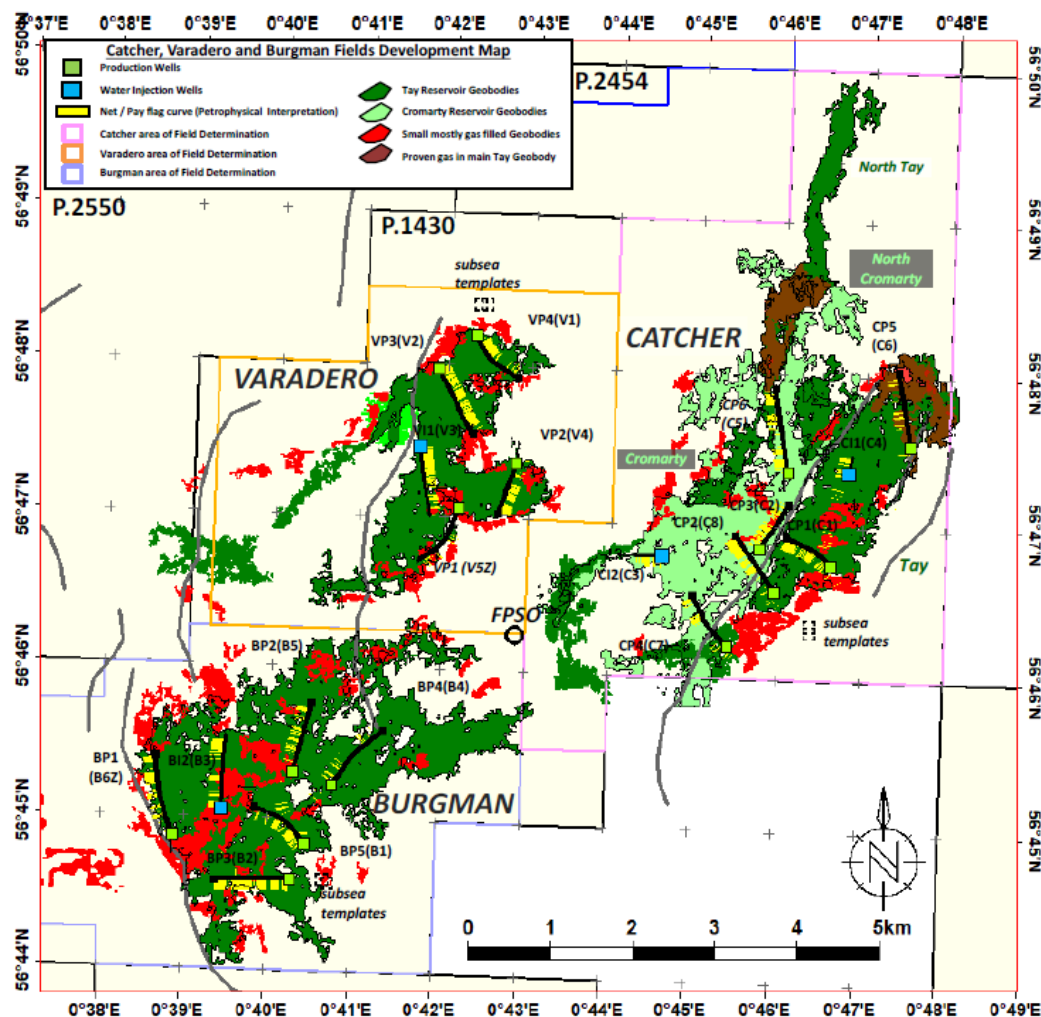


Figure 4.1: Overview of blocks, Catcher Area

Source: ONE-Dyas

The Catcher development comprises an FPSO production hub with a 60,000 stb/d nominal oil production capacity, processing oil from subsea wells on each field. Oil production is supported by water injection and gas re-injection. Production commenced in December 2017 from the Catcher Field. The Varadero and Burgman Fields were brought onstream in January and May 2018 respectively.

The discovered hydrocarbons in the Catcher area lie in structural/stratigraphic traps within Tertiary age Cromarty and Tay Member sandstones of deep marine origin.

Originally deep marine channels and fans were remobilised as fluidised injectites into the shale host rock early in burial history, due to catastrophic dewatering. The injectites form complex reservoir architectures. The large seismically resolvable injectite sills or in-situ sands (“geobodies”) form the main reservoir targets around which networks of smaller seismically unresolvable sands exist. High quality 3D seismic data is available over the licence and rock physics work relating seismic attribute extractions to net pay thickness has been calibrated to the drilling results.

Top depth structure maps for the Catcher, Varadero and Burgman Fields are shown in Figure 4.2, Figure 4.3 and Figure 4.4.

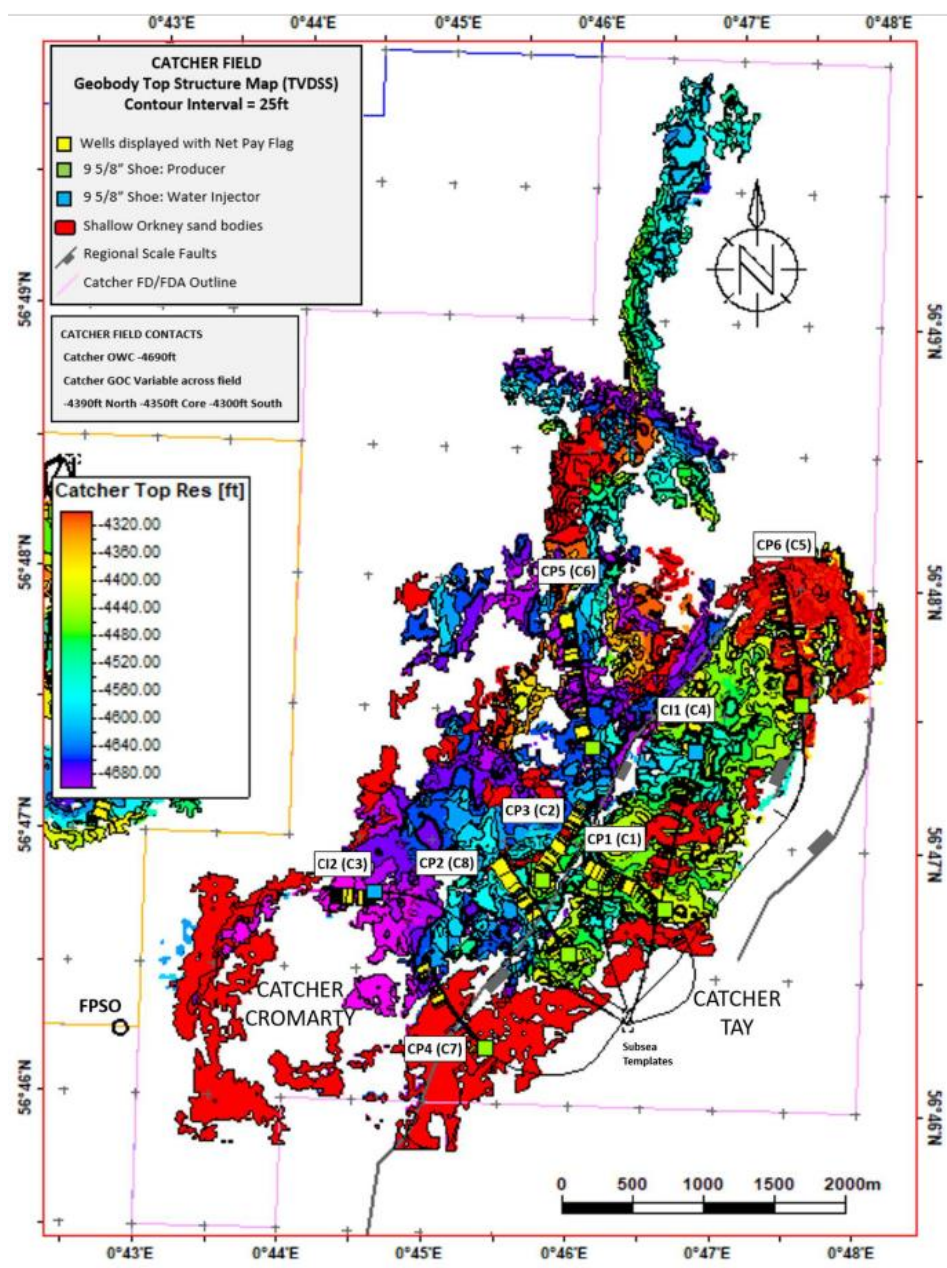


Figure 4.2: Catcher field Top Cromarty and Top Tay depth structure maps

Source: Operator

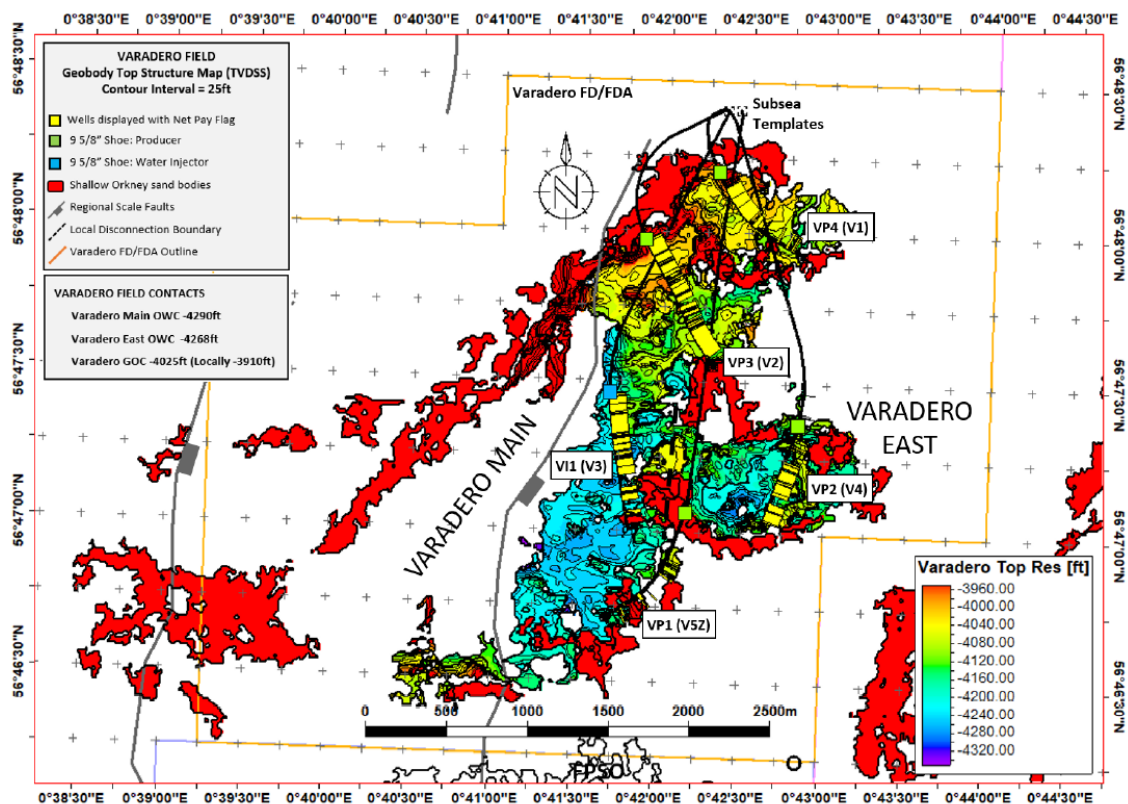


Figure 4.3: Varadero field Top Tay depth structure maps

Source: Operator

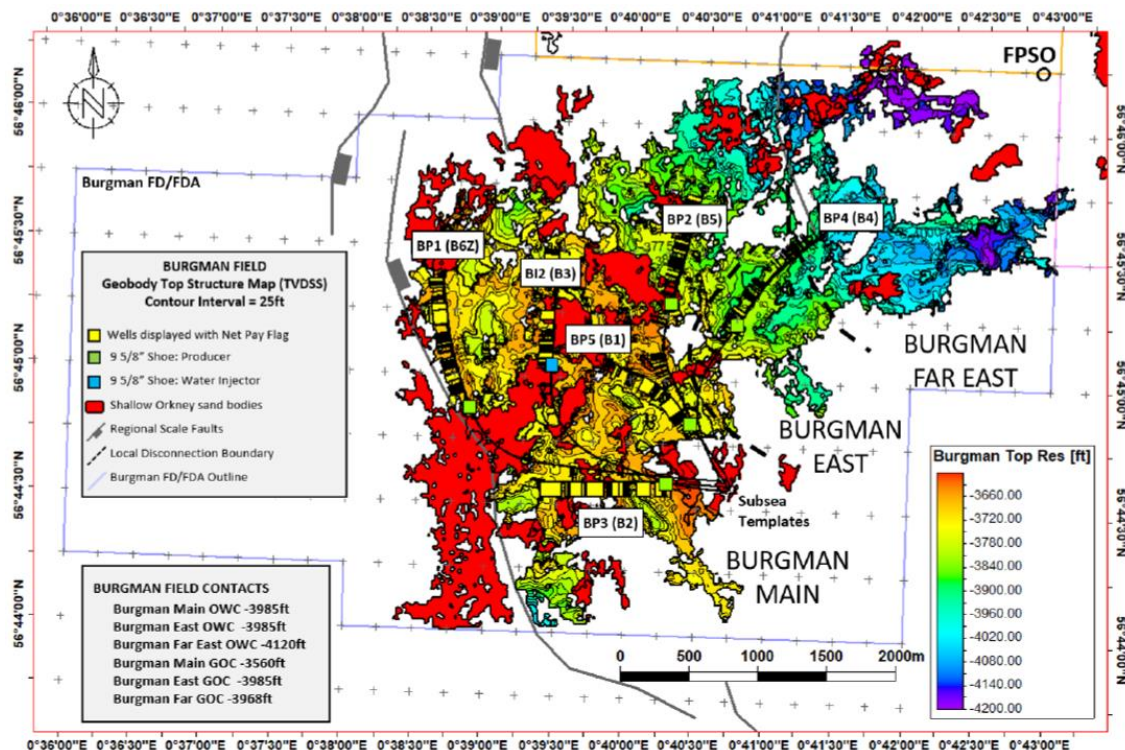


Figure 4.4: Burgman field Top Cromarty depth structure maps

Source: Operator

As at 30 June 2026, cumulative oil production from the Catcher Area was 118 MMstb (Catcher 63 MMstb; Varadero 23 MMstb; Burgman 32 MMstb) and cumulative wellhead gas production was 49 Bscf (Catcher 25 Bscf; Varadero 9 Bscf; Burgman 14 Bscf). In June 2026, the average gross wellhead oil and gas average production rates from the Catcher Area were 19,200 stb/d (at a water cut of 85%) and 13.5 MMscf/d from 17 active wells. There are four active water injection wells supporting production with a combined water injection rate of 118,000 bbl/d. Since the start of 2025, 9.8 Bscf of gas has been re-injected. Production and injection histories (monthly data) for each field are presented in Figure 4.5, Figure 4.6 and Figure 4.7.

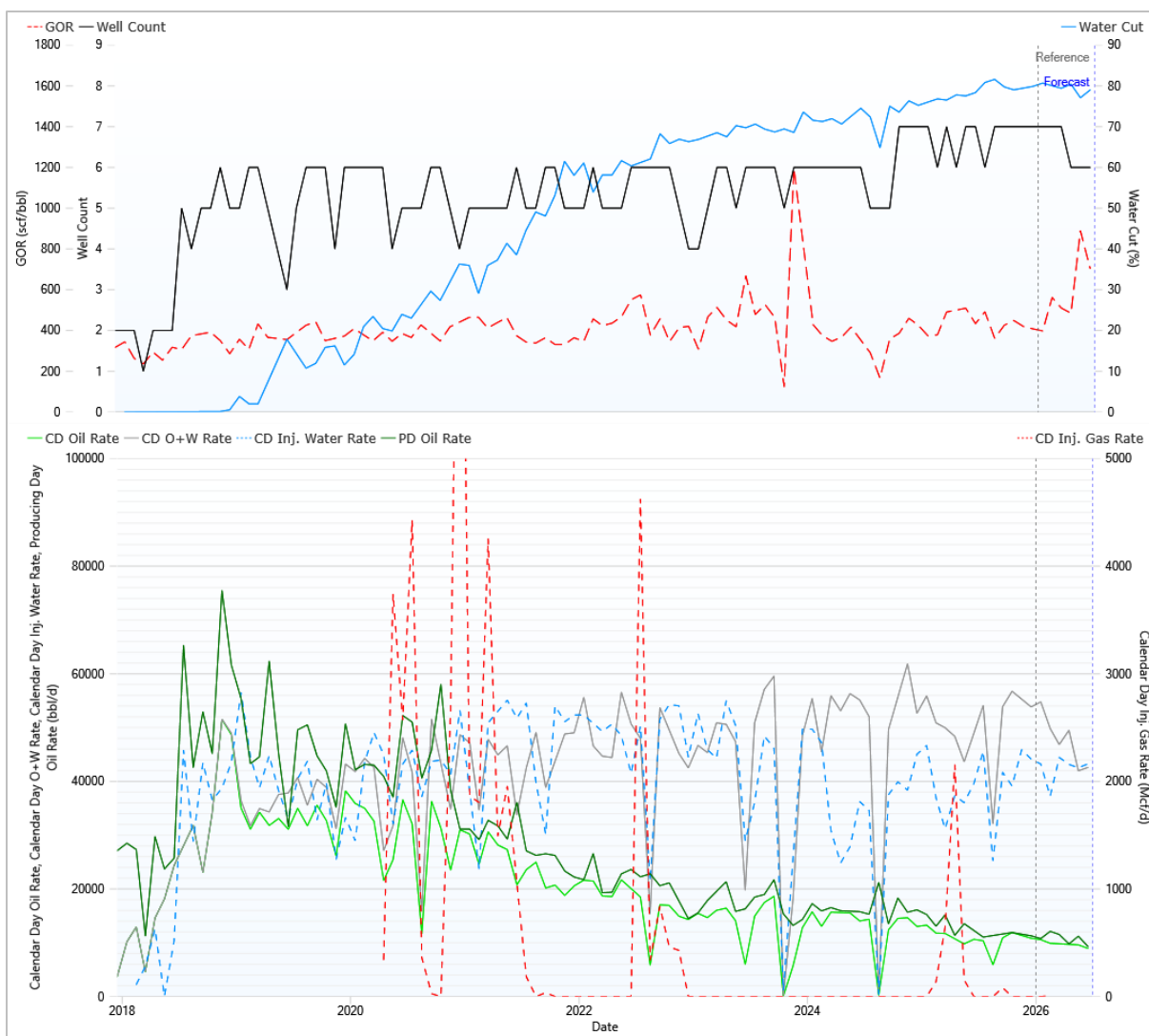


Figure 4.5: Catcher Field production and injection history



Figure 4.6: Varadero Field production and injection history

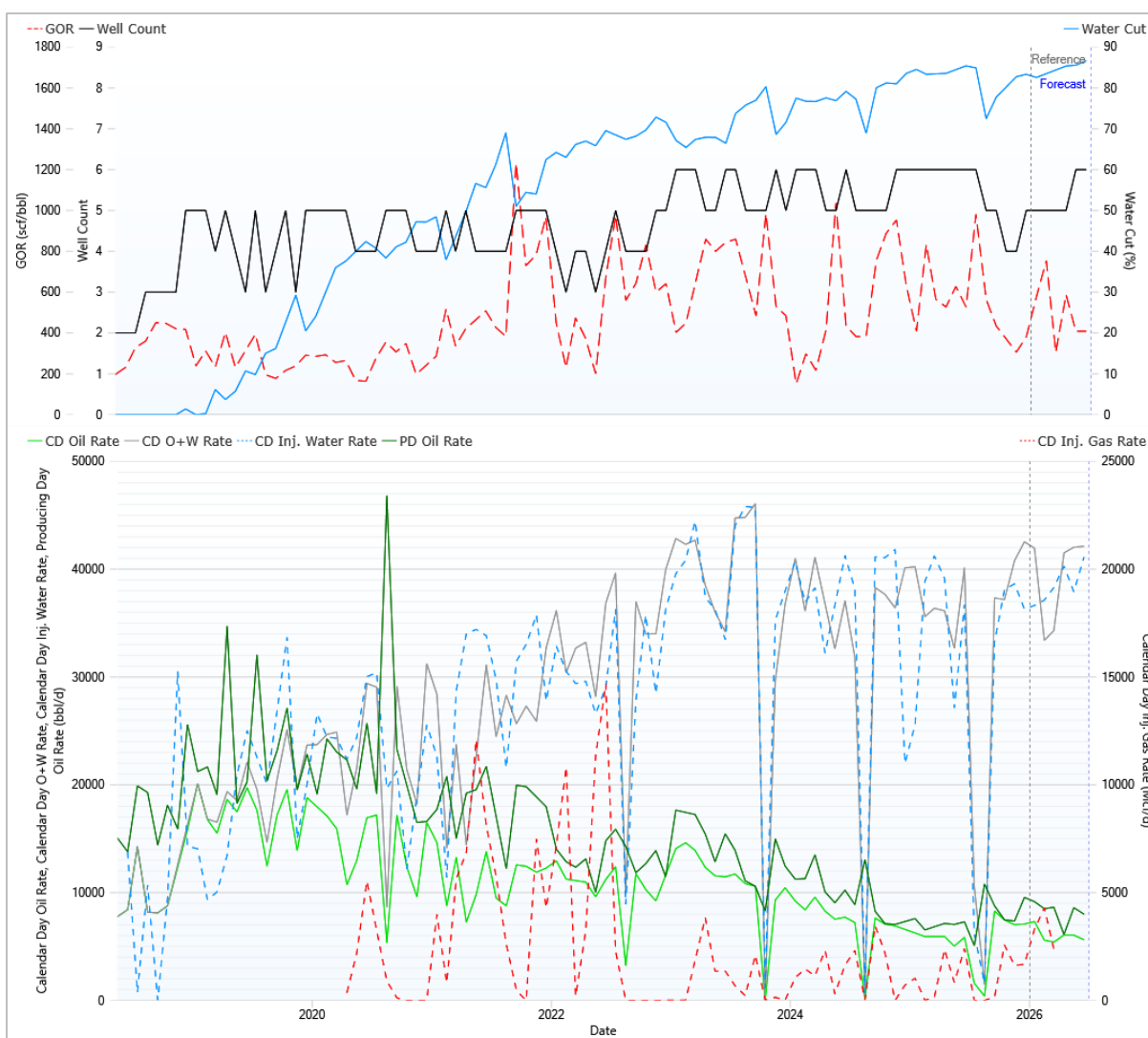


Figure 4.7: Burgman Field production and injection history

Prior to 2021 gross liquids handling was 125,000 bbl/d but the FPSO had some production problems limiting capacity including calcium naphthenate deposition (now managed by injection of acetic acid and dispersants), vibrations within the topsides pipework and pressure spikes due to slugging water cut (solved by topsides works in 2022). Since the start of 2023, the average daily liquid rate has been relatively stable at approximately 135,000 bbl/d, although on occasion reaching 140,000 bbl/d. The primary constraint on production is the gas plant throughput, with too much gas causing export gas compressor alarms and trips.

In 2023 two new wells came on stream, Burgman Far East well (Well BP6) and Catcher North (Well CP7), in January and February 2023 respectively. Well BP6 is less well connected than anticipated and has

produced under natural depletion, whilst Well CP7 initially produced gas but now appears to be producing as an oil well (a similar behaviour to that observed in Well CP5).

4.1 Development Plans

There are no firm capital projects planned in the Catcher Area fields. However, a depressurisation project is planned which involves dropping the reservoir pressure below bubble point to induce solution gas and gas cap expansion drive. The plan is to implement this by stopping or reducing water injection in a phased approach. Depressurisation is expected to start with the Catcher field, although the timing of the project is dependent on the forecast CoP date and the onset of gas deficiency, which itself is dependent on production performance. The main goal of the depressurisation project is to provide additional gas to cover fuel gas requirements; without the project the field is forecast to be fuel gas deficient within the next one to two years.

The JV partners approved long-lead item AFEs for two additional wells (targeting the Varadero West and Burgman North areas) in January 2024, and these were expected to be drilled in 2025. However, both wells have since been put on hold with the Operator communicating to partners that they do not meet the required internal economic hurdles. However, since the recently agreed change in the FPSO lease contract, the Operator has now revived the Varadero West project with FID scheduled in H2 2026 and an aim to achieve first oil in 2027⁹. Sproule ERCE has assessed these opportunities and attributed Contingent Resources.

One further opportunity has been attributed Contingent Resources: a possible water shut-off intervention in Well CP4 in the Catcher Field.

4.2 Estimated Ultimate Recovery

EUR estimates in the Catcher Area fields have been derived with a DCA approach, based on a combination of water-oil ratio (“WOR”) trend extrapolation and oil decline on a well-by-well basis. The DCA captures uncertainty in the potential liquid rate of each well and the WOR. Sproule ERCE has assumed a range in liquid handling capacities of 130,000 – 135,000 – 140,000 bbl/d in the Low, Best and High Cases respectively.

⁹ Between the Effective Date and Issue Date of this report, in August 2026, the field partners approved the Varadero West infill well.

Gas re-injection is an important part of the reservoir management strategy as a portion of the gas stored by re-injection may be produced back to help reduce the need for fuel gas import once the FPSO becomes fuel gas deficient.

At present, three wells (Wells BP2, BP4, and VP2) are being used for occasional gas re-injection. These wells are included in Sproule ERCE's oil production forecasts and the forecast gas-oil ratio ("GOR") takes into account the possible flowback of stored gas (their GORs are generally higher than other wells in the fields).

The Operator forecasts the impact of the depressurisation project using simulation models and sensitivities show a wide range of outcomes depending on the grids and timing of execution. The Operator's latest modelling work suggests the depressurisation project will start to have a negative impact on oil production after approximately eight months, which highlights the sensitivity of the economic value of the project to its timing relative to the asset's CoP date.

Sproule ERCE has not had access to the Operator's latest simulation models and has generated a range of incremental oil and gas forecasts based on a review of information provided in partner meeting material. The latest partner material shows a lower modelled benefit in terms of incremental oil at the best level of confidence versus previous iterations. In the Low Case, Sproule ERCE assumes that some incremental gas will be produced and the oil will be negatively impacted from day one. The Best and High Cases give consideration to the different simulation cases and sensitivities presented by the Operator.

The start of Sproule ERCE's depressurisation is linked to the timing of fuel gas deficiency in Sproule ERCE's forecasts without depressurisation (expected to be March 2027, December 2027 and March 2029 in the Low, Best and High Cases respectively).

A summary of Sproule ERCE's EUR estimates and the inferred best case recovery factors are presented in Table 4.1.

Table 4.1: Catcher Area EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (MMstb) at 30 Jun 2026	RF to date	EUR (MMstb)			EUR Best Est. RF
		(MMstb)	(MMstb)		Low	Best	High	
Catcher	Oil	136	63	46%	72	76	77	56%
Varadero	Oil	65	23	36%	27	28	29	43%
Burgman	Oil	109	32	29%	36	39	40	35%

Notes:

1. Recovery factors are calculated using independent third-party YE23 PIIP estimates.
2. EUR estimates are reported to the end of June 2031 in line with the re-negotiated terms of the FPSO contract.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 4.2. Operating efficiency is forecast to decline from 90.5% in 2026 to 87% from 2030. A 23-day shutdown is planned in August 2026, ten days in 2027, three days in 2028, 13 days in 2029 and five days in 2030. From 2031 there is a planned 25-day shutdown every other year and minor planned downtime in the intervening years.

Table 4.2: Catcher field production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
Catcher	79.3	87.5	88.3	84.9	85.8	80.1	84.8

The gross wellhead oil production forecasts for the Catcher Area, together with the production history since 2022 are presented in Figure 4.8.

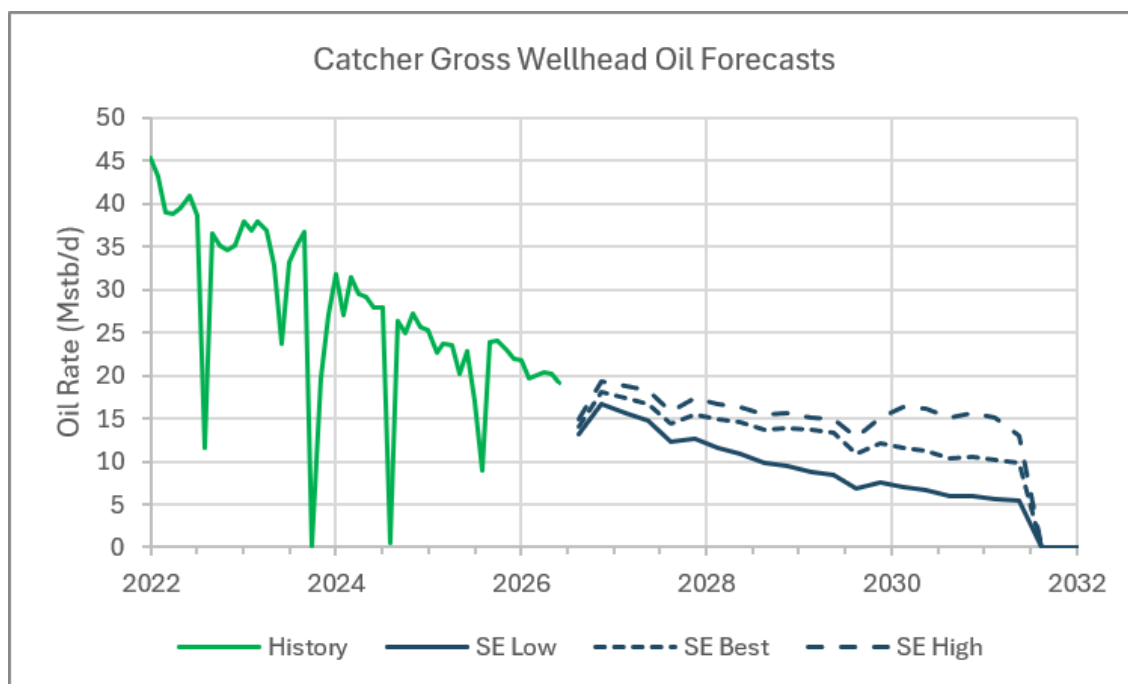


Figure 4.8: Catcher Area gross wellhead oil production forecasts

SE = Sproule ERCE

4.3 Facilities and Costs

The Catcher Area development comprises three oil fields, Catcher, Varadero and Burgman (Figure 4.9). The development comprises an FPSO production hub with a 60,000 stb/d nominal oil production capacity, processing oil from subsea wells on each field. Oil production is supported by water injection. All oil and water injection wells are drilled through 4-slot drilling templates using a jack-up rig and tied back to the FPSO with flowline bundles and flexible risers.

Stabilised oil is exported via shuttle tanker with the balance of gas exported and imported via the SEGAL system.

Sproule ERCE has reviewed and included relevant CAPEX projects from the 2026 WP&B in all forecasts, excluding those activities related to non-reserves work scopes such as exploration.

On 11 July 2025, it was found that one of the tether arrangements on the Burgman mid-water arch had failed, resulting in production being shut down. A subsea campaign was carried out in August 2025 and production was reinstated successfully. Subsequently, a full repair campaign was carried out in Q2 2026.

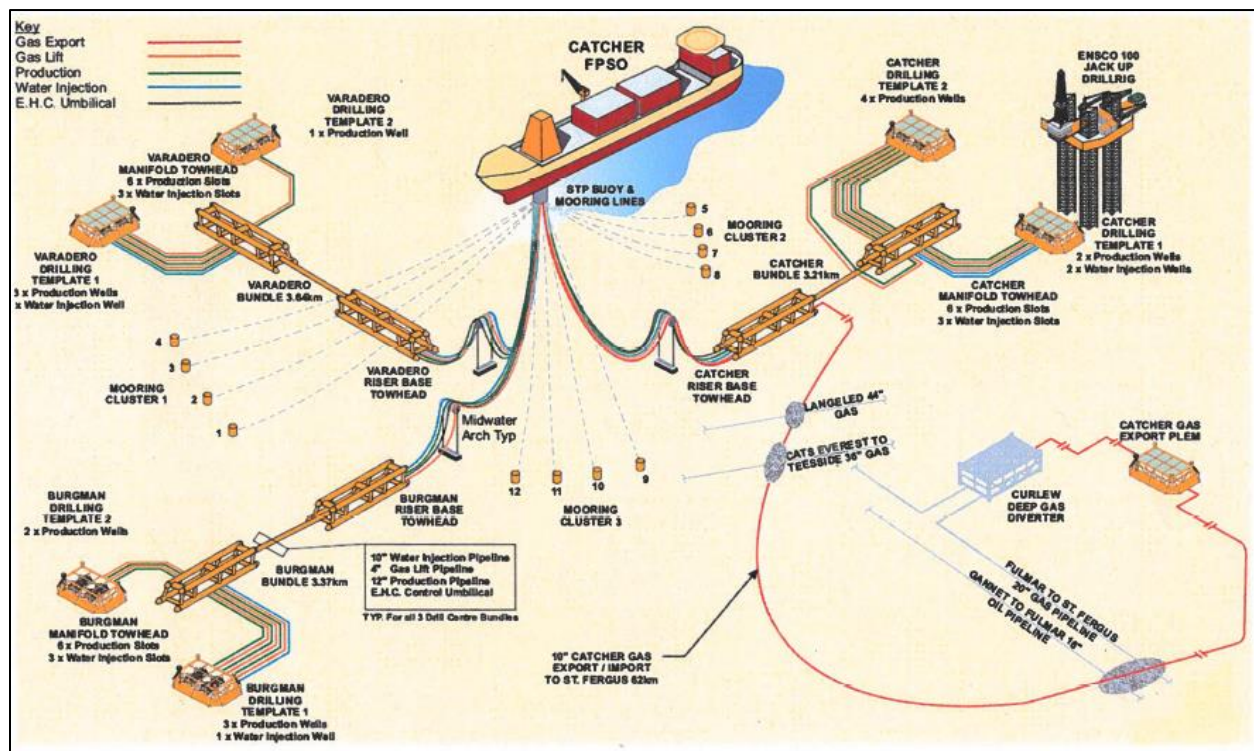


Figure 4.9: Catcher Area development schematic

Source: Operator

Sproule ERCE has reviewed historical expenditures, the 2026 WP&B, and the FPSO lease contract to determine the Catcher OPEX forecast.

In May 2026, an updated Bareboat Charter Agreement ("BBC") was agreed for the Catcher FPSO. The updated terms have been taken into account in this evaluation. The updated BBC allows the Operator to produce up to a maximum of 30 June 2031; Sproule ERCE has truncated its technical forecasts at this point.

Sproule ERCE has accepted the fixed OPEX allocation in the 2026 WP&B, and for 2027 onwards forecasts that fixed OPEX would remain at the 2022-2026 average spend of GBP88.9 MM per annum (Gross, Real 2026). The fixed OPEX makes allowances for the FPSO Contractor's operating and maintenance cost, logistics, General and Administrative ("G&A"), chemicals, subsea maintenance and insurance.

Elements of variable OPEX include the shuttle tanker tariff rate which is set at GBP 1.23/stb (Gross Real 2026), and fuel gas imports which are charged at the UK NBP gas price plus 40%.

FPSO lease costs are forecasted in accordance with the terms specified in Appendix B to the lease agreement. An exchange rate of GBP1.00/USD1.32 is used in 2026, and an exchange rate of GBP1.00/USD1.35 has been applied from 2027.

Total costs allocated for the decommissioning of facilities and plugging and abandonment of wells are GBP325 MM, based on Sproule ERCE's independent benchmarking.

4.4 Reserves

The technical production profiles described in Section 4.2 were converted to sales profiles and used in conjunction with the cost forecasts to determine the Reserves. Gas sales were based on the wellhead gas less fuel and flare consumption, estimated at 7.5 MMscf/d flat, and gas re-injection. The Catcher FPSO will be fuel gas deficient in the future and the cost of purchasing fuel gas has been included.

The Developed Reserves were based on the existing well stock including the depressurisation project. There are no Undeveloped Reserves.

A summary of the gross Reserves is presented in Table 4.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 4.3: Catcher Area gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Catcher	Developed	9.8	24.4	29.0	0.1	3.0	5.6
	Undeveloped	-	-	-	-	-	-
	Total (Dvdp+Undvdp)	9.8	24.4	29.0	0.1	3.0	5.6
	COP (Total)	Jun-28	Jun-31	Jun-31	Jun-28	Jun-31	Jun-31

4.5 Contingent Resources

Sproule ERCE has assigned Contingent Resources to three projects evaluated by the Operator.

Varadero West

Varadero West comprises Tay “wing” injectites on the footwall (western side) of the Varadero fault (Figure 4.10). An infill well targeting this area, drilled as a sidetrack to Well VP1, is under evaluation by the Operator¹⁰. Such a geological feature has not yet been drilled in the Catcher Area but has been developed in analogue fields. There is juxtaposition across the Varadero fault between the Cromarty geobody in Varadero West and the Tay geobody in Varadero Main and a hardening response on 4D seismic data in

¹⁰ Serica has informed Sproule ERCE that the partners approved the Varadero West infill well in August 2026, after the Effective Date.

the Cromarty geobody in Varadero West, suggesting it has been partially swept, which would indicate communication with the main Varadero field.

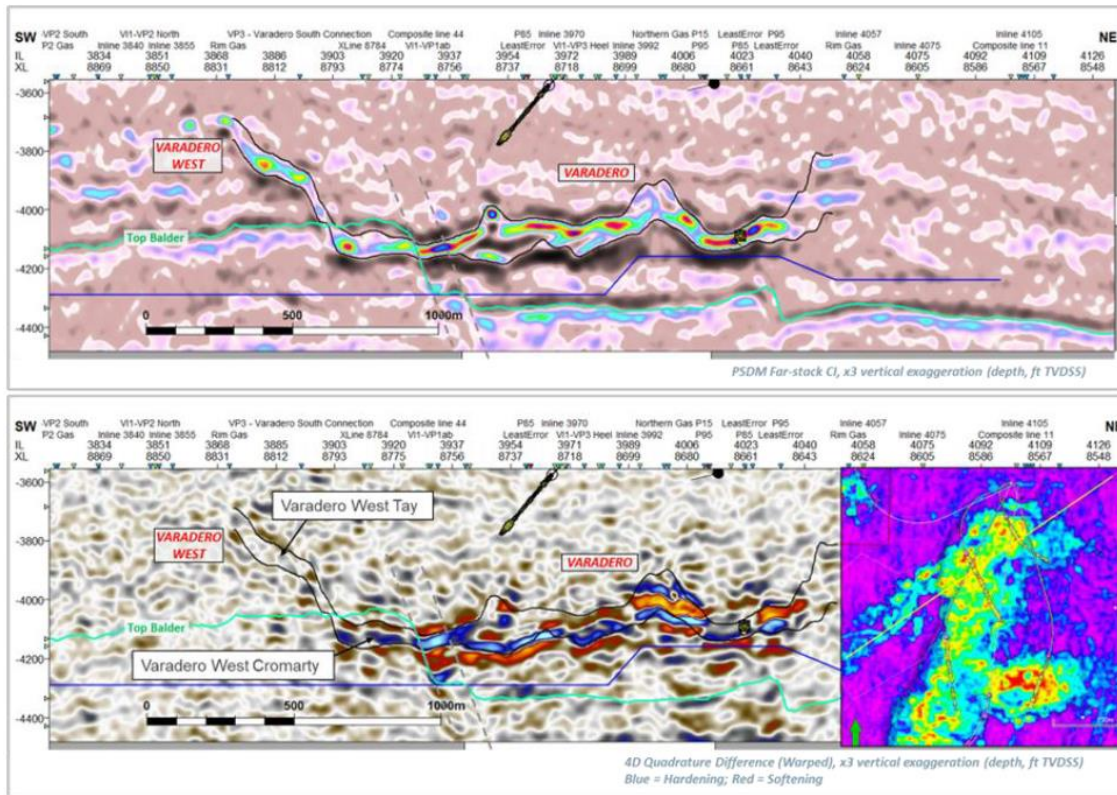


Figure 4.10: NE-SW seismic cross section from Varadero Main to Varadero West

Source: Operator

Sproule ERCE has reviewed the Operator's stock tank oil initially in place ("STOIIP") estimates for the Varadero West area and found them to be reasonable. One of the key uncertainties is the presence of a gas cap, and the depth of a gas-oil contact ("GOC"). Sproule ERCE has applied a range of recovery factors (15 – 25 – 40%) to the Operator's STOIIP estimates to calculate a range in EUR. This range is based on the recovery factors seen in different areas of the Varadero field.

Burgman North

The Burgman North area is mapped as a down-dip reservoir extension from the toe of Well BP2 (Figure 4.11). There is one remaining slot on the Burgman subsea template that could be used to target Burgman North. The seismic amplitudes in the Burgman North area are brighter than at Well BP2 and there is subsequently a gas risk associated with the target.

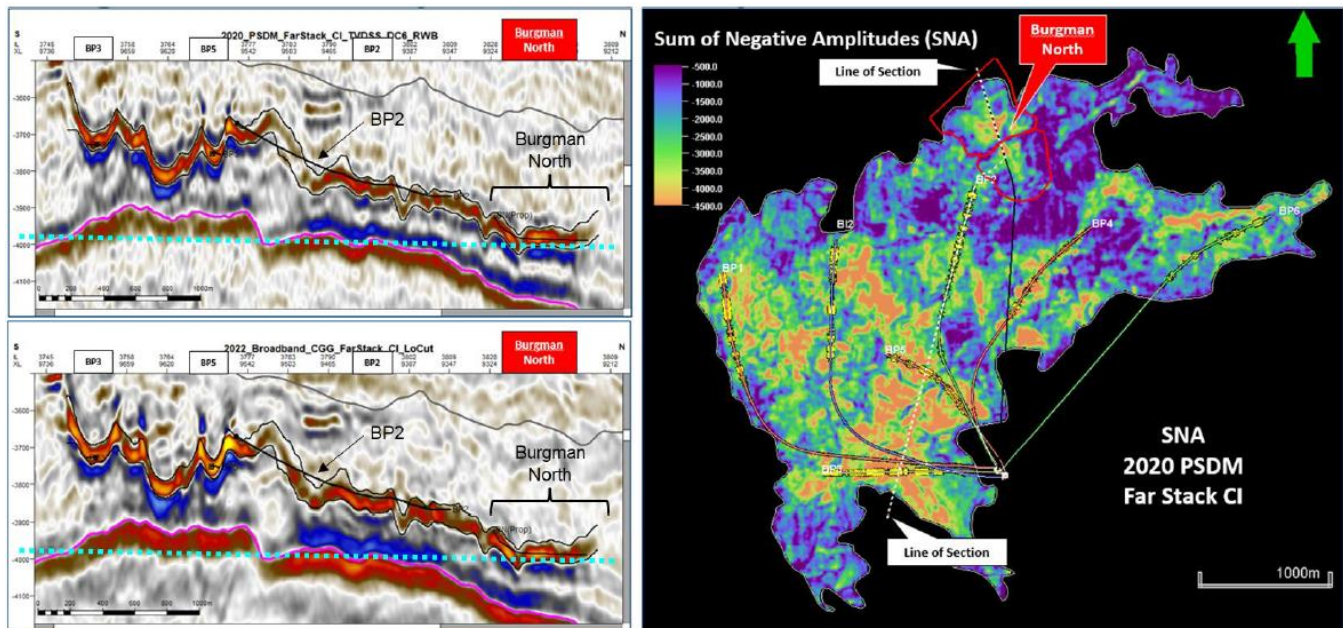


Figure 4.11: N-S seismic cross section through Burgman North (left) and Burgman SNA map (right)

Source: Operator

Sproule ERCE's estimates of Contingent Resources for the Burgman North area are based on independent estimates of STOIP and recovery factors. Sproule ERCE has assumed the area is gas-filled in the Low Case, with zero incremental oil recovery. This is highlighted by the Operator as a “failure case”.

In the Best and High Cases, ERCE assumes Burgman North is oil-filled with no gas cap, with different oil-water contacts (“OWC”s) used in each case. The best case assumes an OWC similar to the Burgman Core area, whilst the high case assumes a deeper OWC supported by seismic amplitude analysis. Sproule ERCE has applied recovery factors of 20% and 30% in the best and high cases. These recovery factors consider a range of possible drive mechanisms and possible communication with the Burgman Core area.

CP4 Water Shut-Off

A water shut-off opportunity in Well CP4 is under evaluation. The well has produced very little since 2020 due to a water cut of approximately 90%. The majority of the well's completion is in the Cromarty reservoir and early tracer analysis suggested it provides the majority of the production. The intervention would involve setting a plug either partially into or above the Cromarty and producing the well from the heel completion in the Tay reservoir.

Sproule ERCE's estimates of Contingent Resources are derived assuming a range of water cut reductions and liquid rates following the shut-off, guided by simulation modelling work by the Operator.

There is currently no alignment between partners on the way forward regarding the opportunity.

Organic Oil Recovery

A OOR pilot project has recently been completed in the Burgman Field; the trial commenced in July 2025 with injection of microbes through Well BI2. The concept of the OOR project is that the introduction of microbes reduces the residual oil saturation and thus releases mobile oil into the reservoir that migrates towards production wells. Further injection is currently on hold pending an evaluation of the results of the pilot project.

Sproule ERCE's estimates of Contingent Resources are based on assuming a range of lag times (the period between microbe injection and response at the production wells) and water cut reductions associated with the pilot project. No Contingent Resources are attributed to any subsequent OOR phases. A summary of gross Contingent Resources attributed to the Catcher Area fields is provided in Table 4.4.

Table 4.4: Summary of gross Contingent Resources in the Catcher Area

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
Varadero West	0.9	2.1	4.1	0.0	0.5	1.0	DP
Burgman North	-	0.7	2.1	-	0.3	0.8	DOH
CP4 WSO	0.1	0.4	1.1	0.1	0.2	0.6	DOH
Organic Oil Recovery	0.3	0.7	1.6	0.1	0.3	0.7	DP

5. Golden Eagle Area Development

The GEAD consists of the Golden Eagle, Peregrine and Solitaire oil fields, which lie within License P300 (Block 14/26a, sub-area Rest of Block) and License P928 (Block 20/01a, sub-area North). The licences are in the UK Central North Sea; water depth is approximately 115 m. CNOOC is the operator. The GEAD location is shown in Figure 5.1.

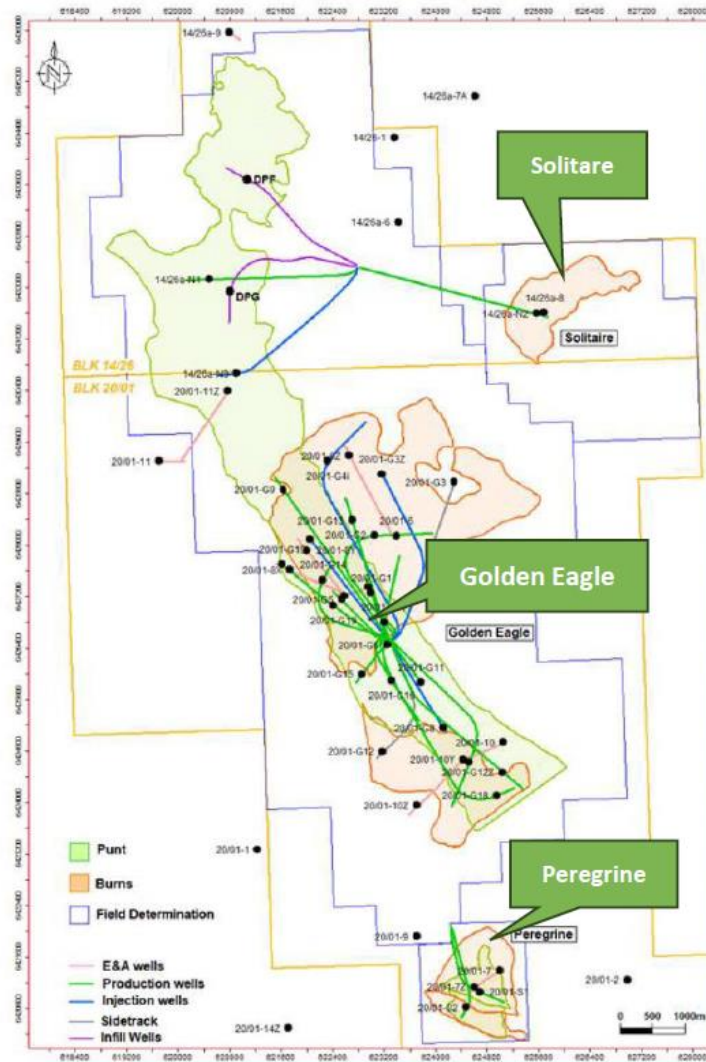


Figure 5.1: Overview of licences, GEAD

Source: Operator

The first field to be discovered in the GEAD area was the Solitaire Field in 2001. The Golden Eagle Field was then discovered in 2006, and the Peregrine Field in 2008. The Golden Eagle and Peregrine Fields obtained development and production consent in October 2011, followed by the Solitaire Field

development plan (“FDP”) in December 2012. The GEAD has been unitised across the two licences, P928 (block 20/01a sub-area North of Block and P300 (block 14/26a sub-area Rest of Block) since its development.

The fields produce oil from the Burns and Punt sandstone members. The Burns reservoir, which is an Upper Jurassic to Lower Cretaceous age turbidite sandstone reservoir, is found in all three fields, while the Punt reservoir, which is a Lower Cretaceous age turbidite sandstone reservoir, is only found in the Golden Eagle and Peregrine fields (Figure 5.2).

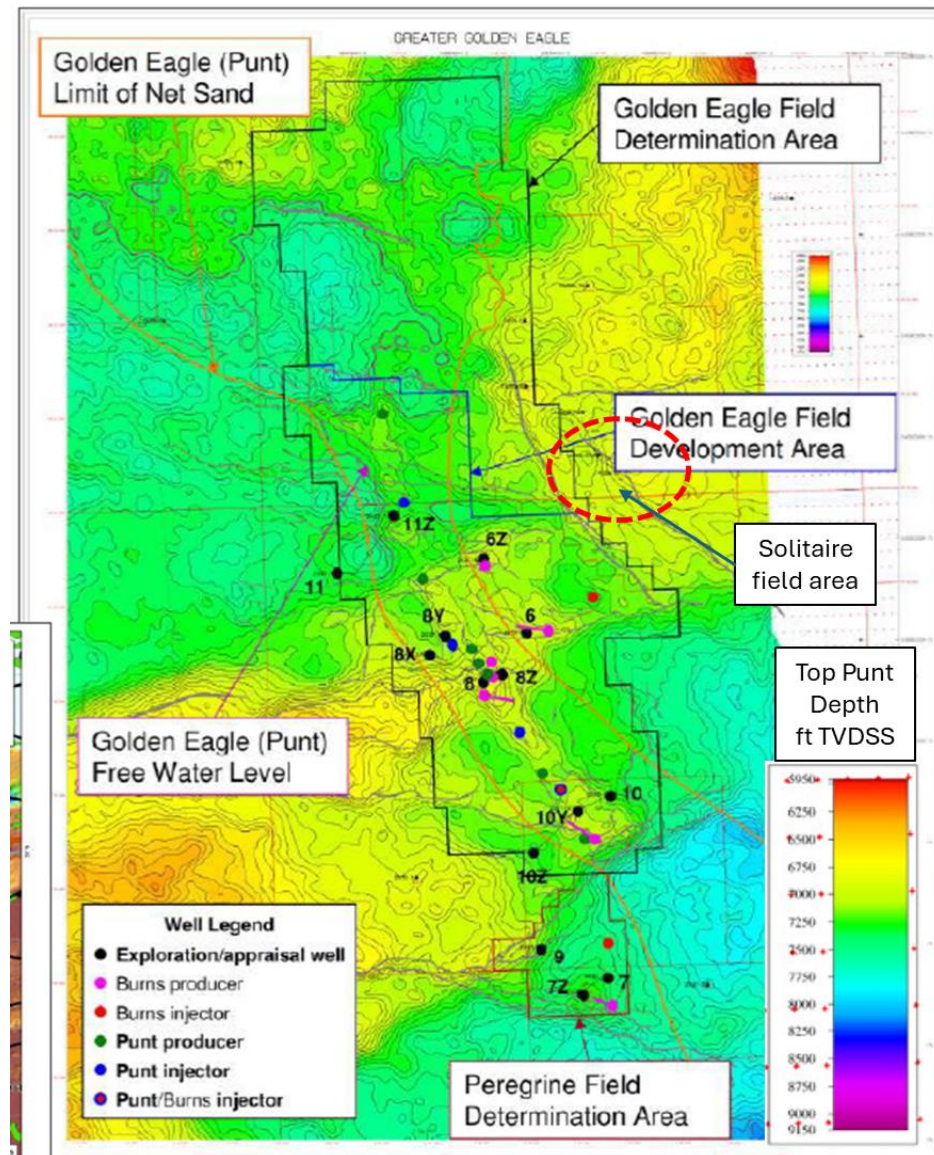


Figure 5.2: GEAD Top Punt depth structure map

Source: Operator

Production started in November 2014 from the Golden Eagle Field. Production from the Peregrine and Solitaire Fields started in February 2015 and December 2015, respectively. The GEAD has been developed by both platform and subsea tie-back oil producers and water injectors, which are tied to a wellhead platform (“WHP”) on the Golden Eagle Field. The Peregrine and Solitaire Fields' wells are subsea tiebacks to the Golden Eagle WHP.

The average oil production rate peaked at ~75,000 stb/d in 2016. In June 2026, the average oil rate is approximately 8,640 stb/d from 18 active producers at a water cut of 91% (Figure 5.3). The average water injection rate is 88,073 bbl/d from five active injectors. Cumulative oil and gas production is 148 MMstb and 32 Bscf respectively.

Through Q2 2026, three mud acid stimulation workovers were successfully carried out, adding approximately ~240 stb/d of oil production.

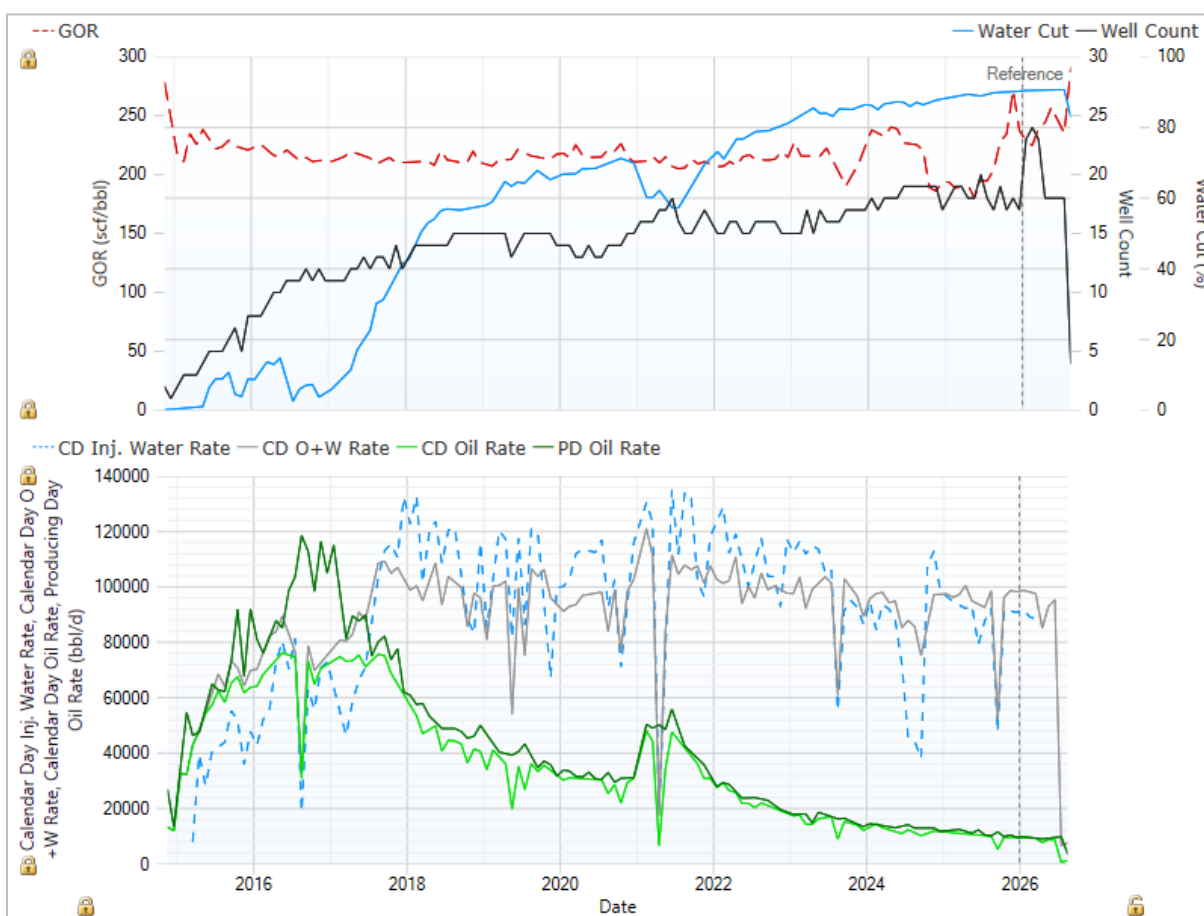


Figure 5.3: GEAD Fields production and injection history

Oil is exported to the Flotta Oil terminal via Piper/Claymore; gas was exported to St. Fergus via SAGE but the field is now fuel gas deficient and there is no gas export.

5.1 Development Plans

There are no firm plans for future infill drilling in the GEAD fields. The Operator continues to screen for future opportunities and has recently completed a “Locate the Remaining Oil” (“LTRO”) study. Two of the opportunities from this study have been evaluated by Sproule ERCE in this report and are classified as Contingent Resources.

5.2 Estimated Ultimate Recovery

Sproule ERCE’s EUR estimates for the existing producers were derived using DCA, primarily by well level 1+WOR extrapolation with liquid rate trends, reconciled with the PIIP proposed by the Operator.

Sproule ERCE’s gross EUR estimates for the GEAD area are presented in Table 5.1.

Table 5.1: GEAD Area EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. at 30 Jun 2026	RF to date	EUR (MMstb)			EUR Best Est. RF
		(MMstb)	(MMstb)		Low	Best	High	
Golden Eagle	Oil	295	130	44%	144	151	159	51%
Peregrine	Oil	33	12	37%	12	13	13	38%
Solitaire	Oil	11	5	43%	5	6	6	51%

Notes:

1. Recovery factors are calculated using the Operator’s PIIP best estimates derived volumetrically or from material balance methods.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 5.2. Operating efficiency is generally high (~97%). An almost two-month shutdown is planned across July/August 2026 and then every five years (the next being in 2031). In the intervening years there are 27-days of shutdowns planned each year.

Table 5.2: GEAD production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
GEAD	71.8	92.7	92.7	92.7	92.7	82.0	92.7

The gross wellhead oil production forecasts for the GEAD, together with the production history since 2022 are presented in Figure 5.4.

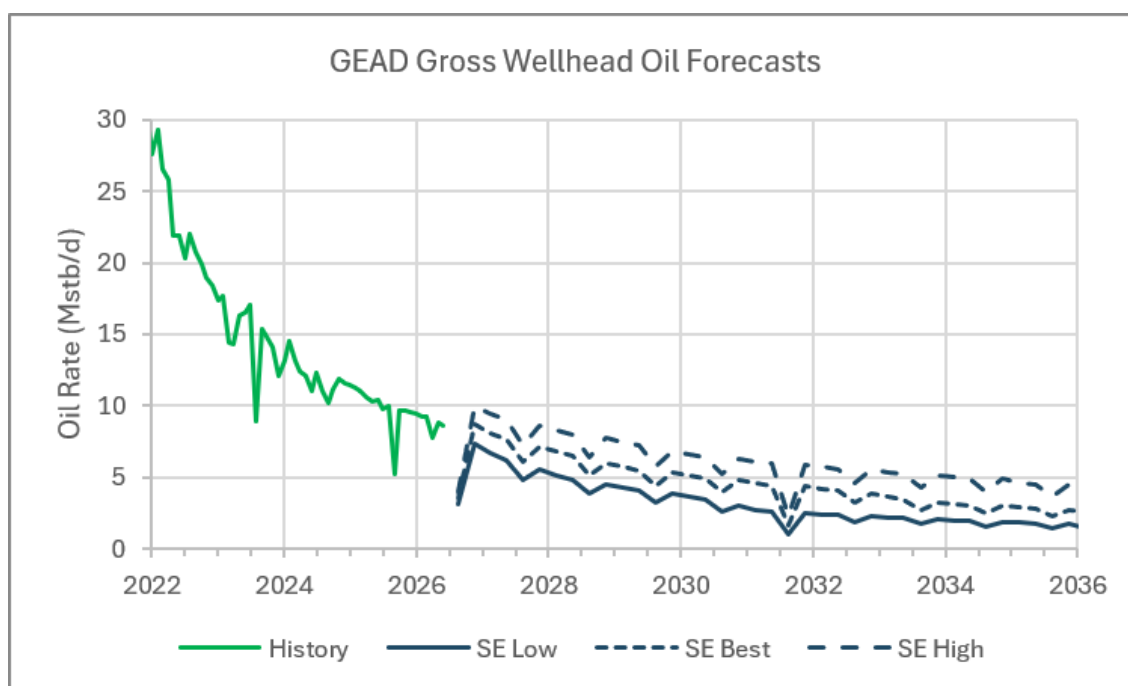


Figure 5.4: GEAD gross wellhead oil production forecasts

SE = Sproule ERCE

5.3 Facilities and Cost

The GEAD comprises 26 wells, including 20 production wells and six water injection wells. Facilities consist of a production, utilities and quarters platform, bridge-linked to a WHP on the Golden Eagle field, with the Peregrine and Solitaire accumulations developed as subsea tie-backs to the WHP. Oil is exported via the Repsol-operated Flotta Pipeline System and terminal, while gas export/import is via the SAGE system.

CAPEX for the GEAD is forecast to consist predominantly of facilities-related activities and G&A expenditure over the period 2026 to 2028, with only minor sustaining capital assumed thereafter through field life. Sproule ERCE has reviewed the Operator's latest WP&B CAPEX estimates and considers them to be reasonable. However, costs associated with the water injector conversion pilot have not been included in the Sproule ERCE 2026 forecast, as this project is classified as Contingent Resources.

OPEX comprises fixed OPEX, fuel import costs, CO₂ emissions costs, and tariff / OPEX-sharing costs. Sproule ERCE has reviewed the Operator's latest WP&B and LoF cost estimates and considers these to be reasonable. A fixed OPEX assumption of approximately GBP45–50 MM per annum has been applied through field life. In addition, an incremental GBP25 MM has been included in 2035 to reflect costs associated with anticipated life extension works.

For fuel import costs, Sproule ERCE has applied a 12% uplift to its gas price forecast, consistent with recent budget actuals. Sproule ERCE has adopted the Operator's emissions forecast, while applying the Sproule ERCE UK ETS price deck to the forecast emissions profile. The OPEX-sharing component comprises the Flotta diesel fuel cost share and the Flotta CO₂ emissions cost share. The Flotta oil tariff has been assumed at GBP1.99 per bbl, in line with the latest Operator budget assumptions.

Sproule ERCE has reviewed the ABEX assumptions presented in the Decommissioning Security Agreement ("DSA") and considers them to be reasonable. These are understood to include the plugging and abandonment of all wells, the decommissioning of the offshore facilities, including the PUQ and WHP, the decommissioning of subsea tie-back infrastructure and associated pipelines, together with associated removal, disposal and site clearance activities, where applicable. Accordingly, Sproule ERCE has adopted the Operator's abandonment cost estimate for the GEAD of approximately GBP583 MM.

Sproule ERCE's forecasts of production, CAPEX, OPEX and ABEX are presented in Appendix 3, with all costs stated in 2026 real terms.

5.4 Reserves

The technical production profiles described in Section 5.2 were converted to sales profiles. The oil sales are based on the exported wellhead volumes with no adjustment. The GEAD area is fuel gas-deficient, with fuel gas import currently ongoing. Therefore, there are no gas Reserves.

A summary of the gross on block Reserves is presented in Table 5.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 5.3: Golden Eagle Area gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
GEAD	Developed	5.6	10.4	19.3	-	-	-
	Undeveloped	-	-	-	-	-	-
	Total (Dvdp+Undvdp)	5.6	10.4	19.3	-	-	-
	COP (Total)	Jun-29	Jun-31	Dec-34	Jun-29	Jun-31	Dec-34

5.5 Contingent Resources

The Operator's LTRO studies have identified two opportunities in the Punt 2E and 2F reservoirs, which are currently being matured for development and have been evaluated by Sproule ERCE (Figure 5.5).

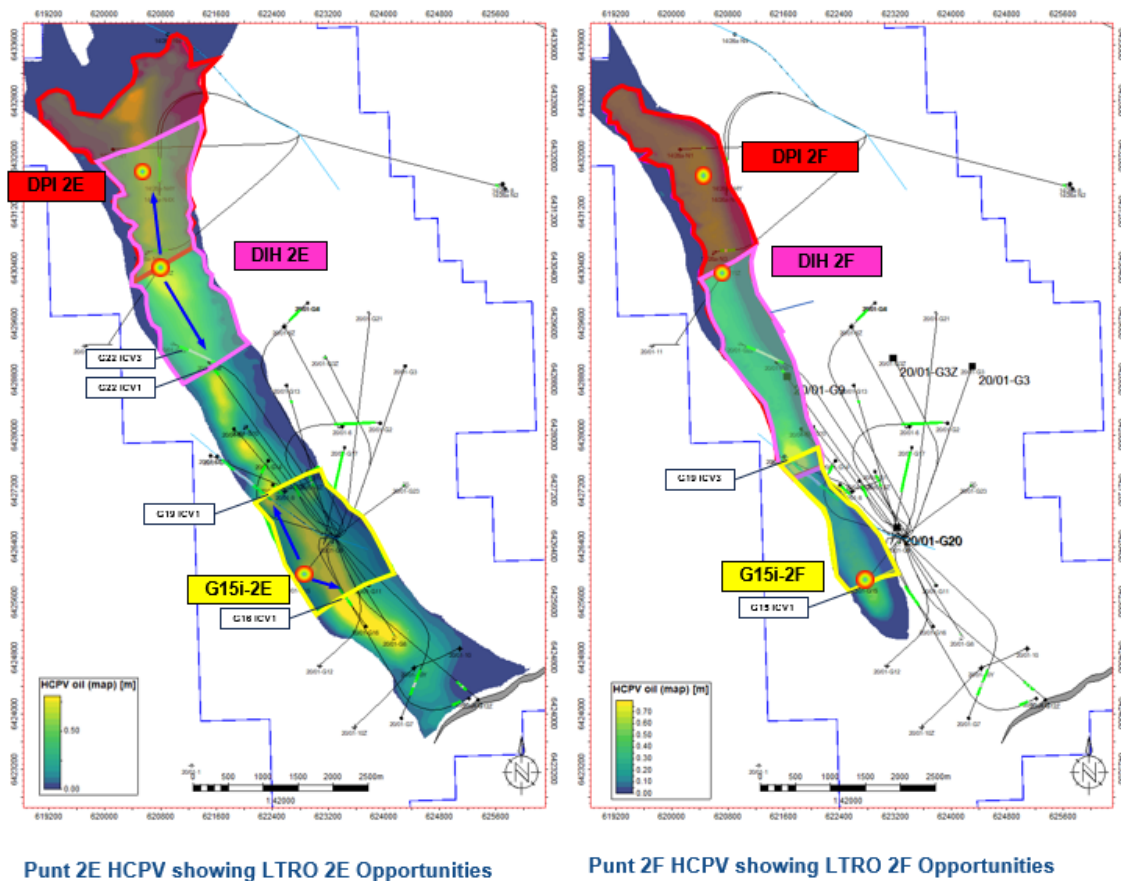


Figure 5.5: Locations of opportunities in Punt 2E and 2F reservoirs

Source: Operator

The first opportunity is the conversion of Well G15 producer to water injection to support Wells G19 and G16 in the southern part of the field¹¹. Well G15 is on the margin of the Punt 2E/2F channel feature and has a different reservoir character on well logs compares to Wells G16 and G19. As such, Sproule ERCE considers there is a risk injected water may not support the wells as expected.

Sproule ERCE considers the Operator's estimated remaining STOIP for the area to be reasonable and has deterministically applied an incremental recovery factor range (incremental to the no further activity case recovery factors) of 5 – 17.5 – 30% to estimate the Contingent Resources. The wide range of recovery factors reflects the uncertainty in sweep efficiency.

¹¹ Between the Effective Date and Issue Date of this report, in August 2026, the field partners approved the project to convert Well G15z to water injection.

The second opportunity is the drilling of a dedicated Punt 2EF water injector (named “DIH”) in the northern part of the field supporting Wells N1 and G22 (Punt 2E producers) and possibly also Well G19. An infill production well (named “DPI”) is planned in a failure case of the DIH injector. Sproule ERCE has only assessed the DIH water injector, assuming a success case.

The reservoir quality in this area of the field is poor, with NTG reaching 35% in Well 11z; the NTG is lower in Well G22 which is one of the wells the DIH injector is intended to support. One nearby injection well, Well N3, was not completed in these reservoirs partly because of the poor reservoir qualities.

Sproule ERCE considers the operator's estimated remaining STOIIIP for the area to be reasonable and has deterministically applied an incremental recovery factor range of 5 – 12 – 30% to estimate the Contingent Resources. The wide range of recovery factors reflects the uncertainty in reservoir quality and sweep efficiency.

Sproule ERCE’s gross incremental volumes estimates attributable to the two Contingent Resource projects are presented in Table 5.4.

Table 5.4: Summary of gross Contingent Resources in GEAD area

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
DIH	0.2	0.9	3.3	-	-	-	DP
G15a Conversion	0.2	0.9	2.4	-	-	-	DP

6. Greater Markham Area

The GMA is a cluster of offshore natural gas fields located in the southern North Sea, straddling the maritime boundary between the United Kingdom and the Netherlands. The fields lie in relatively shallow waters (approximately 30–50 m) within UK blocks such as 49/5 and adjacent Dutch sectors, forming part of the mature Southern North Sea gas province.

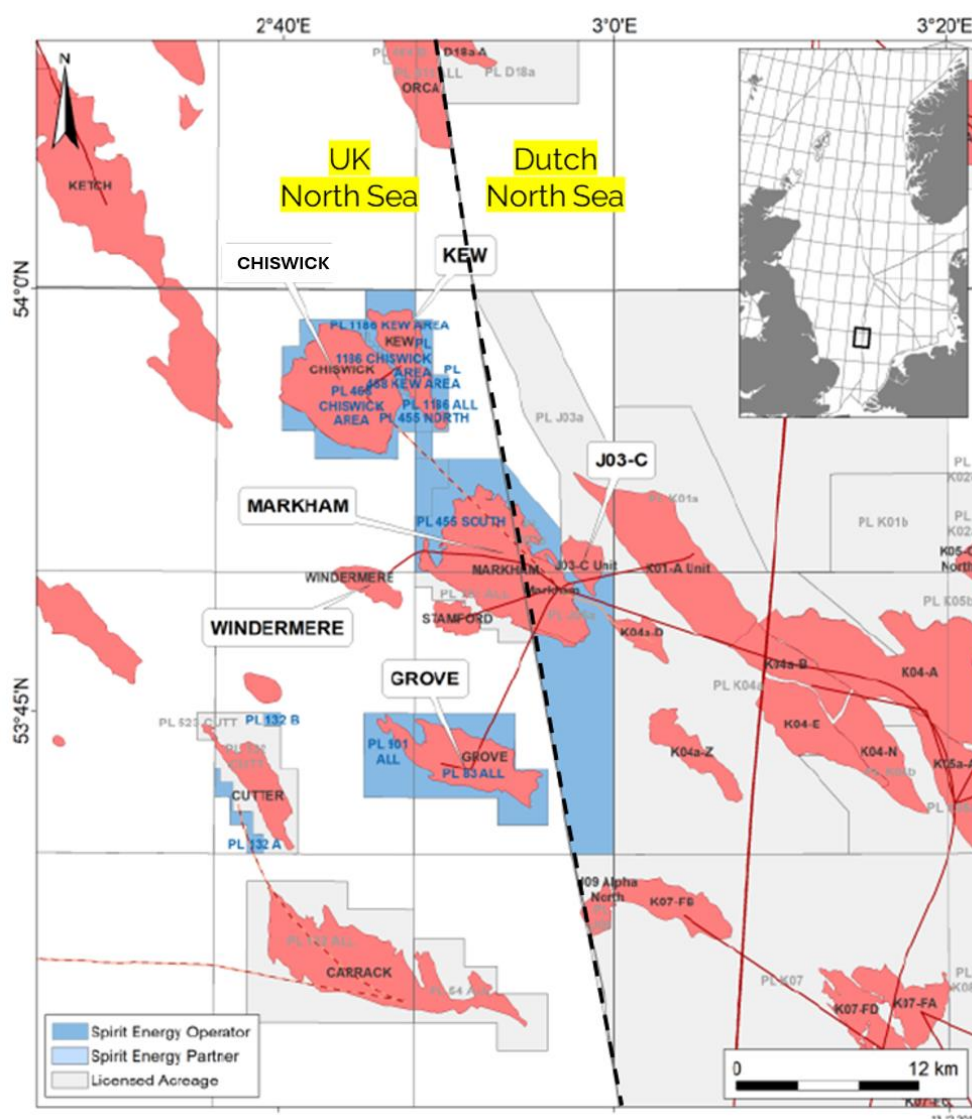


Figure 6.1: Overview of licensed blocks, Greater Markham Area

Source: Operator

The GMA hub comprises the Spirit Energy-operated Markham, Chiswick, Grove and Kew Fields and the non-operated J3C Field. Additional third-party fields (K01-A and K04a-D) share the facilities.

Development of the GMA began in the 1990s, when the central Markham Field was brought into production. Over time, nearby discoveries were progressively tied back to existing infrastructure, creating a hub-based development system that allows multiple smaller accumulations to be produced economically through shared facilities.

These fields are geologically related as they all lie within the Southern Permian Basin, extending across the United Kingdom and the Netherlands. The basin developed during the Late Carboniferous and contains thick sequences of continental sandstones overlain by evaporites. The primary reservoir is the Upper Carboniferous Westphalian A-C sandstones (Chiswick, Kew and Grove), with gas produced from Lower Permian aged Rotliegend Group sandstones at J3C. The Carboniferous reservoirs are generally poor-moderate quality fluvial sandstones characterised by low permeability and compartmentalisation. In contrast, the Lower Permian Rotliegend Group reservoir at J3C comprises moderate quality aeolian sandstones with generally improved reservoir properties.

The GMA fields produce dry natural gas, with minimal liquids (condensate) through the J6A platform, located above the Markham Field, which itself is no longer in production. The June 2026 average wellhead production rates from the area were around 45 MMscf/d of gas and 367 bbl/d of condensate from nine active wells. The cumulative gas production, as at 30 June 2026, from the active fields is approximately 704 Bscf, with current recovery factors ranging from 37% to 95% for the different fields. The total GMA gas production history is shown in Figure 6.2, with a more recent history by well shown in Figure 6.3.

Compression is installed at the J6A platform and currently two trains are in operation: the existing system uses two gas turbines driving centrifugal compressors (LLP and LP) for export pressure. The Chiswick and the Kew Fields produce to the LP compressor, whilst the Grove and J3C Fields produce to the LLP compressor. The LLP compressor failed in July 2025 which led to the shut-in of the Grove and J3C Fields. However, in October 2025 the Grove Field was successfully put on production through the LP compressor. The LLP compressor was successfully reinstated at the end of April after a 17-day shutdown on the J6A platform; J3C production was subsequently restarted in May.

In late January 2026, all production from GMA fields was stopped due to a failure of the diesel firewater pump on the J6A platform. Production was restarted in early March 2026.

The Markham J6A platform acts as a processing hub and four pipelines ultimately deliver gas to Den Helder in the Netherlands.

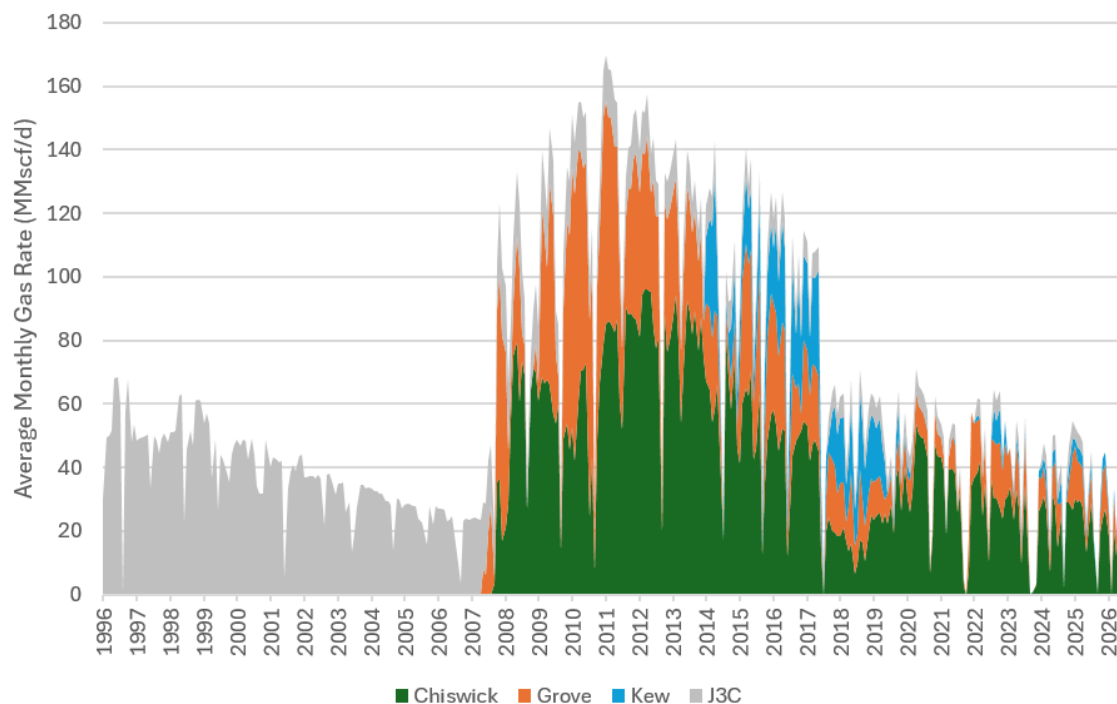


Figure 6.2: GMA gas production history, by field

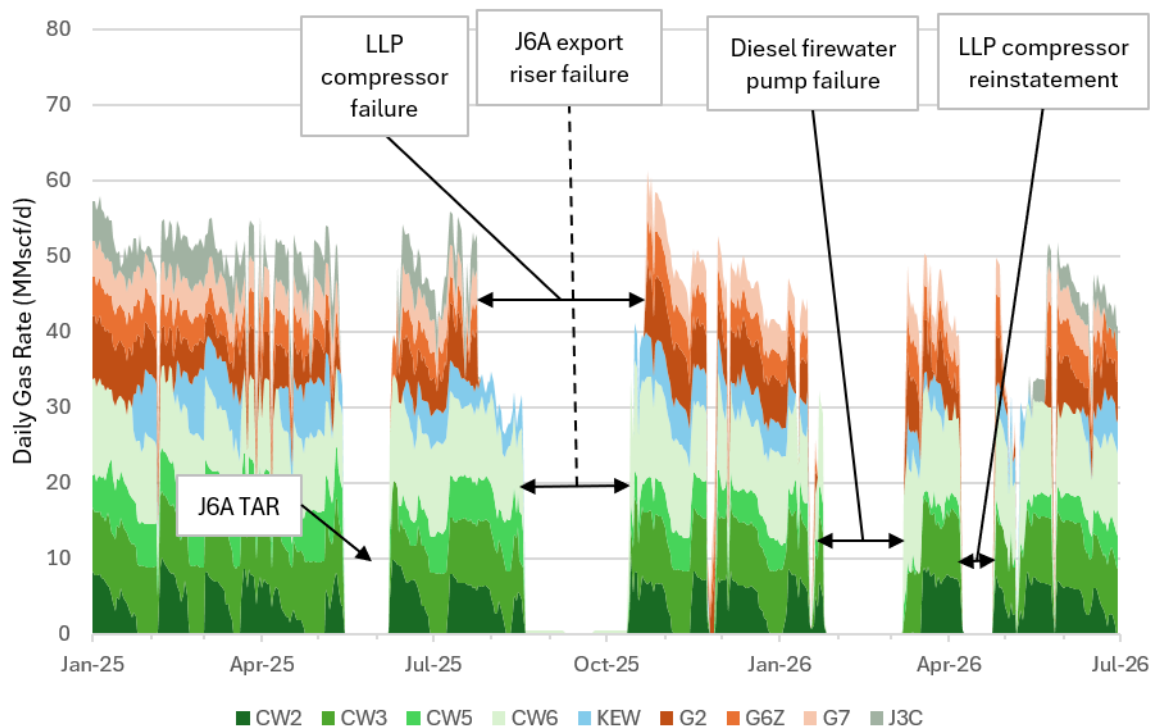


Figure 6.3: GMA daily gas production history, by well (2025 to 30 June 2026)

Chiswick Field

The Chiswick Field is located in UK Block 49/4a in the Southern North Sea, approximately 18 km northwest of the Markham Field. Development wells are drilled from the Chiswick Normally Unattended Installation (“NUI”) and tied back via an 18 km 10" pipeline to the Markham J6A facility before the gas is exported. The Chiswick Field was discovered in 1984 by Well 49/4-1 that tested gas at rates of 8.5 MMscf/d from the Carboniferous interval in the Gamma fault block. Additional fault blocks were appraised between 1986 and 1989.

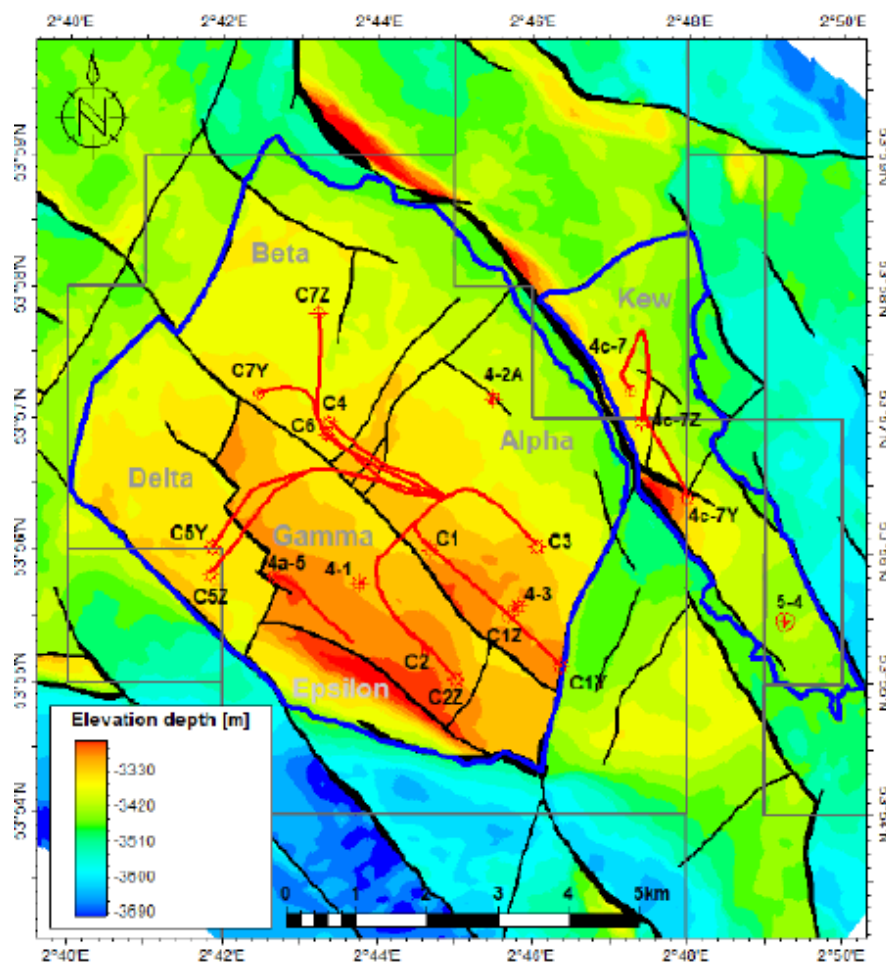


Figure 6.4: Chiswick field top structure map

Source: Operator

The first phase of development involved the drilling of three hydraulically propped fracture-stimulated horizontal wells, with first gas being achieved in September 2007. Further development was carried out between 2009 and 2019, with fracture-stimulated, deviated or horizontal wells often penetrating multiple fault blocks. A total of twenty wells have been drilled, including exploration and appraisal wells, in the different fault blocks. In June 2026, four wells were online and produced an average of 27 MMscf/d of

gas, with 223 bbl/d of condensate; cumulative production, as at 30 June 2026, was 297 Bscf of gas and 3.5 MMstb of condensate.

Kew Field

The Kew structure is a northwest-southeast trending horst separated from the Chiswick field by a major northwest-southeast fault and a structural low. The primary reservoirs are Carboniferous-aged fluvial sandstones. This gas field was discovered in 1988 by Well 49/5-4 and further appraised by Well 49/4c-7z in 2009. The field is developed by a single sub-horizontal well (Well 49/04c-7Y), drilled along the crest of the structure. The well was stimulated with multiple propped vertical hydraulic fractures along the wellbore in the Carboniferous reservoir to enhance production. First production was achieved in January 2014 and peak gas rate reached ~45 MMscf/d. The field experienced water breakthrough in 2018 and this led to a decline in gas production due to issues with produced water handling and oil in water, with subsequent production performance hindered by water-related issues. The Operator carried out studies in 2023 to identify the origin of the water ingress, possibly restricted to a single reservoir zone with an opportunity of water shutoff (this opportunity is still under evaluation).

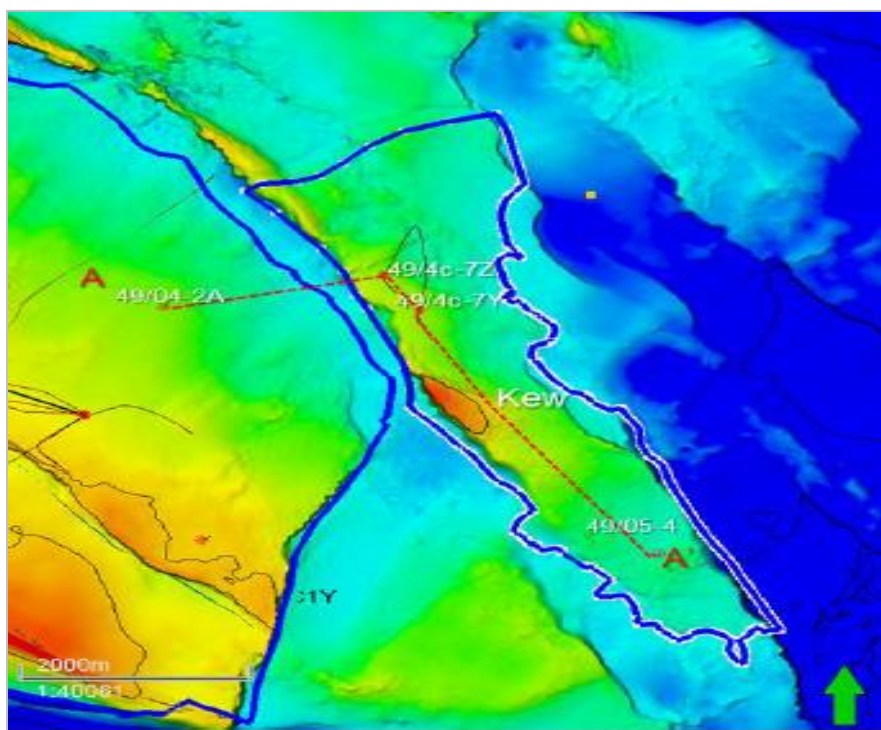


Figure 6.5: Kew field top structure map

Source: Operator

In June 2026, the field produced an average of 3 MMscf/d of gas, with 24 bbl/d of condensate, understood to be constrained by water handling capacity. Cumulative production, as at 30 June 2026, was 42 Bscf of gas and 0.4 MMstb of condensate.

The gas is routed via a ~3 km pipeline to the Chiswick NUI.

Grove Field

The Grove field was discovered in 1971 by Well 49/10-1. The well encountered a Rotliegend aged Leman Sandstone Formation as well as a Carboniferous aged Barren Red Measures (“BRM”) sandstone. The Leman failed to flow on test, however the BRM flowed at 8 MMscf/d. Subsequent analysis of the Drill Stem Test (“DST”) indicated the formations were heavily damaged by the drilling mud. In 1989, Shell drilled Well 49/10a-2 to test the down-dip limits of the structure, finding the Leman and BRM sands were much thinner and tighter than previous penetrations.

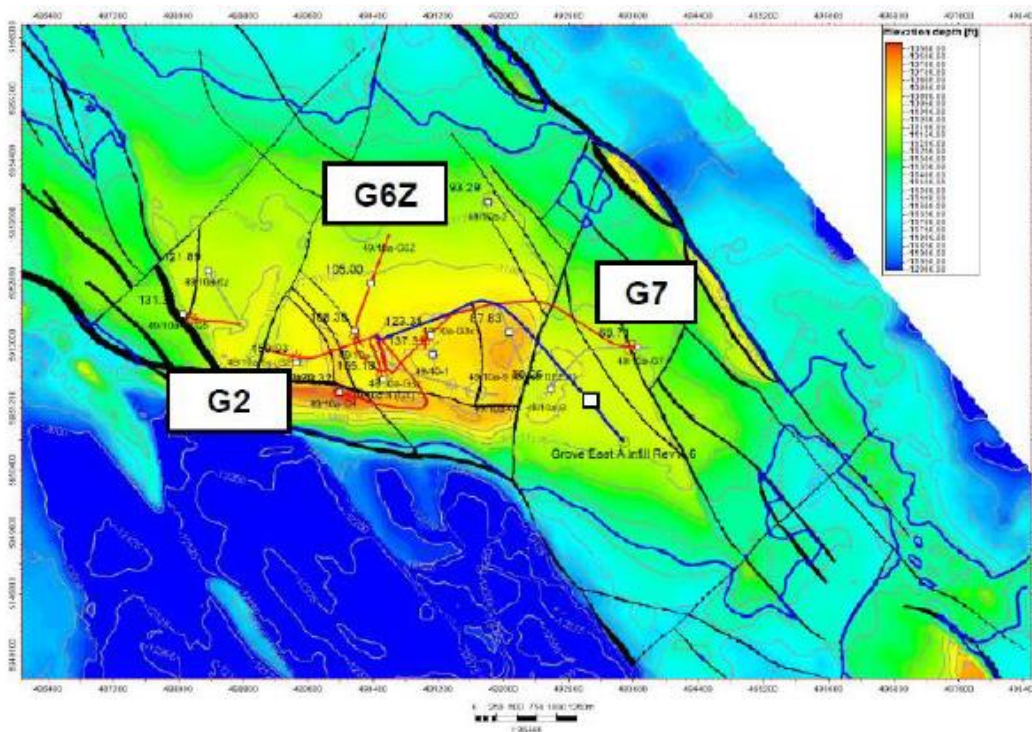


Figure 6.6: Grove field top structure map

Source: Operator

In November 2004, a third well was spudded, Well 49/10a-4, which encountered thicker Leman and BRM sands than were found in the discovery well. The sands have average porosities of 9-12% and have permeabilities ranging from 0.1 md to 10 mD. Both zones were commingled, via a slotted liner, and had a combined test rate of 25 MMscf/d of gas and 325 stb/d of condensate. The zones were isolated using a packer and plug, and the well was suspended pending installation of production facilities. Additional appraisal drilling was carried out ahead of first production in April 2007.

6.1 Development Plans

The Operators of the GMA fields do not have firm plans for further development drilling. Sproule ERCE has reviewed one planned infill drilling project in the eastern area of the Grove Field, which has attributable Contingent Resources.

6.2 Estimated Ultimate Recovery

In light of the compartmentalised nature of the GMA fields, Sproule ERCE has reconciled estimates of ultimate recovery with GIIP estimates, differentiating between field volumetric and connected GIIPs where appropriate. Sproule ERCE has reviewed the Operator's static models and reports, where available.

Sproule ERCE has estimated the EUR of the fields using DCA, performed at the well level. For the current well stock, uncertainties identified by Sproule ERCE relate to risk of water breakthrough and liquid loading, certain issues with water allocation and the minimum flowing tubing head pressure ("FTHP") achievable by individual wells. Sproule ERCE has prepared forecasts at low, best and high levels of confidence, using a DCA approach based on extrapolation of trends of gas rates versus time and versus cumulative production. Forecasts of condensate production have been prepared by applying constant CGR values, based on historical data, to the wellhead gas forecasts.

The total EUR estimates for each field are presented in Table 6.1. EUR estimates are reported to 30 June 2029 as this is the planned CoP date of the GMA hub. Recovery factors in Table 6.1 are calculated using the Operator's best case volumetric estimates (all blocks) and were compared to analogues for the Carboniferous reservoirs/developments for reasonableness.

Table 6.1: GMA EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Grove	Gas	414	154	37%	160	163	165	39%
Chiswick	Gas	469	297	63%	311	316	319	67%
Kew	Gas	82	42	51%	42	44	45	53%
J3-C	Gas	222	211	95%	211	213	215	96%

Notes:

1. Recovery factors are calculated using the Operator's PIIP best estimates derived volumetrically or from material balance methods.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 5.2. Production efficiency in the GMA fields is uncertain and different assumptions have been made in the low and best/high cases. In total, 44 days of planned downtime are assumed by the Operator in 2026 (19 days in April to reinstate LLP compression and a 25 day turnaround ("TAR") in September) and 34 days in 2027. There are no planned TARs in 2028 or 2029 given CoP is expected at the end of June 2029.

Table 6.2: GMA production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
GMA	60.0	63.0	70.0	72.0	-	-	-

The gross wellhead gas production forecasts for the GMA assets, together with the production history since 2020 are presented in Figure 6.8.

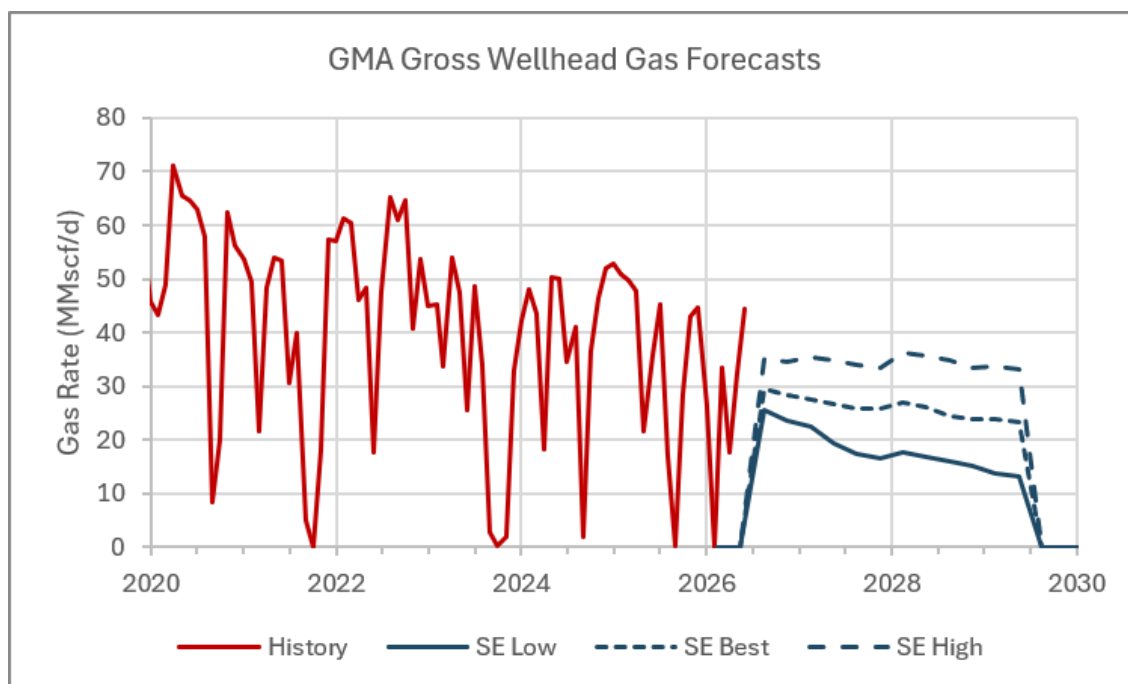


Figure 6.8: GMA gross wellhead gas production forecasts

SE = Sproule ERCE

6.3 Facilities and Cost

The GMA is a mature, cross-border Southern North Sea gas hub spanning both the UK and Dutch Continental Shelves. The hub comprises the Spirit Energy-operated Markham, Chiswick, Grove and Kew Fields, together with the TotalEnergies-operated J3C, K1a and K4aD Fields.

The Chiswick Field is produced via a NUI wellhead platform tied back to the Markham J6A platform via a 10-inch, 18 km gas pipeline, while the Kew Field is developed via a subsea well tied back to the Chiswick NUI via a 6-inch, 3.1 km pipeline. The G5 subsea well is tied back to the Grove NUI, which in turn is tied back to the J6A Markham platform via a 10-inch, 13.4 km pipeline. The K4aD Field comprises a subsea well tied back directly to the J6A Markham platform via a 4.5-inch, 7.5 km pipeline. The J3C development comprises an extended reach well tied back to the J6A platform, while the K1a Field is produced via a NUI wellhead platform tied back to the J6A platform via a 14-inch, 9.1 km gas pipeline.

Gas from all GMA fields is processed via the Spirit Energy-operated J6A platform and exported through the c.160 km West gas transport pipeline system to the Den Helder onshore terminal, where final separation, conditioning and distribution take place. Accordingly, the GMA cost structure is driven by shared offshore processing infrastructure, common export and tariff arrangements, and ongoing subsea

and pipeline integrity requirements, necessitating appropriate allocation of common operating and transportation costs across the contributing fields.

Following the LLP compressor failure in 2025, the Operator completed installation of a replacement compressor during Q1 2026 and implemented corrective actions to improve cooling medium performance. Inspection of the removed cooler confirmed significant degradation and, in the absence of a spare unit, refurbishment and replacement options are being evaluated. Planned cooler replacements for the LPB and LPA compressor trains have been deferred to 2026 and 2027, respectively.

Minimal CAPEX is forecast for the GMA fields. Markham CAPEX, as presented in the 2026 WP&B, has been allocated across the fields within the Sproule ERCE forecasts on a production pro rata cost-sharing basis. For the Chiswick Field, Sproule ERCE has included a nominal fixed CAPEX allowance of approximately GBP2-3 MM per annum through field life to provide for ongoing facilities-related maintenance and minor capital works that may be required to support continued operations.

Field OPEX is categorised as Fixed OPEX, Tariff, and Cost Share. Where provided, Fixed OPEX has been adopted in line with the Operator's budget forecasts through field life. Tariff comprises the Capacity Tariff, Den Helder Tariff, and POSA Tariff, which have been adopted in accordance with the Operator's work programme and budget. Markham OPEX has been allocated across the fields on a production pro rata OPEX-sharing basis.

Sproule ERCE understands that, as part of the Spirit Transaction, Spirit Energy will retain all abandonment liability for the operated assets in the portfolio, including the GMA fields, up to an agreed cap. The Operator's estimates of ABEX are within the agreed cap and therefore ABEX has been excluded in the calculation of NPVs for the GMA fields.

6.4 Reserves

The technical production profiles described in Section 6.2 were converted to sales profiles. Gas produced at the wellhead is reduced by 5% for fuel and flare consumption. Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profiles.

A summary of the gross Reserves is presented in Table 6.3 together with CoP dates, with a breakdown by asset.

Table 6.3: GMA gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Chiswick	Developed	0.1	0.2	0.2	10.9	17.6	20.4
	Undeveloped	-	-	-	-	-	-
	Total (Dvdpd+Undvdpd)	0.1	0.2	0.2	10.9	17.6	20.4
	COP (Total)	Dec-28	Jun-29	Jun-29	Dec-28	Jun-29	Jun-29
Grove	Developed	0.0	0.0	0.1	2.7	6.8	10.3
	Undeveloped	-	-	-	-	-	-
	Total (Dvdpd+Undvdpd)	0.0	0.0	0.1	2.7	6.8	10.3
	COP (Total)	Sep-27	Dec-28	Jun-29	Sep-27	Dec-28	Jun-29
Kew	Developed	0.0	0.0	0.0	0.5	1.2	1.5
	Undeveloped	-	-	-	-	-	-
	Total (Dvdpd+Undvdpd)	0.0	0.0	0.0	0.5	1.2	1.5
	COP (Total)	Mar-27	Jun-28	Sep-28	Mar-27	Jun-28	Sep-28
J3C	Developed	0.0	0.0	0.0	0.2	1.9	3.7
	Undeveloped	-	-	-	-	-	-
	Total (Dvdpd+Undvdpd)	0.0	0.0	0.0	0.2	1.9	3.7
	COP (Total)	Dec-26	Jun-29	Jun-29	Dec-26	Jun-29	Jun-29

6.5 Contingent Resources

Sproule ERCE has reviewed one future project to which Contingent Resources have been attributed. The area is penetrated by Well G7, which is on production and has produced 7.5 Bscf of gas to date.

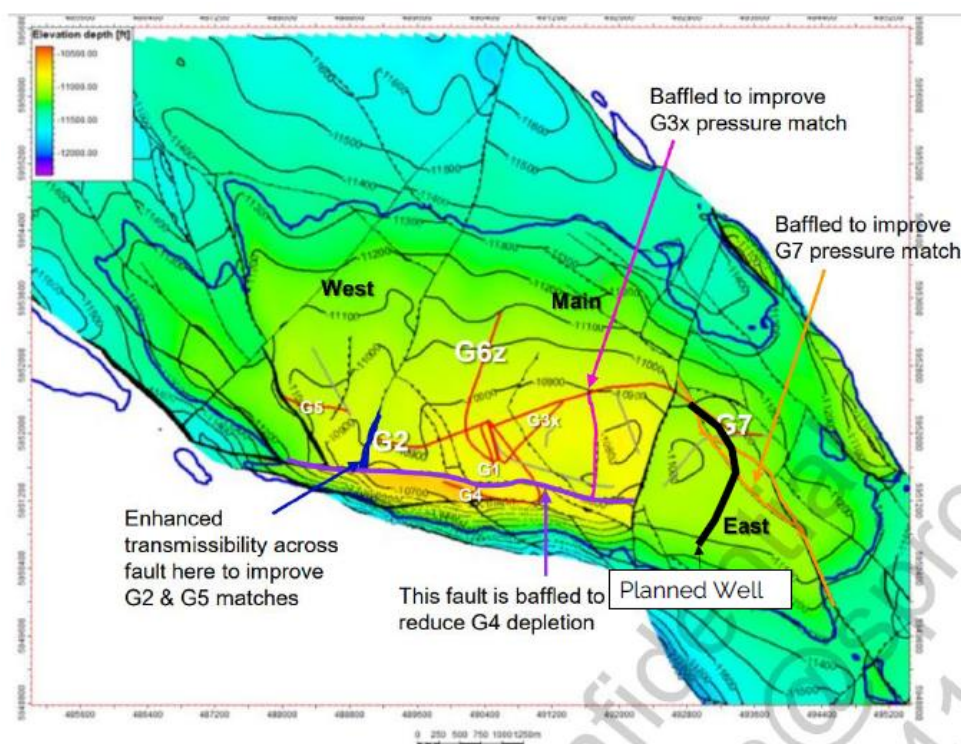


Figure 6.9: Grove East Area and planned well location

Source: Operator

Well G7 encountered a deeper gas-water contact (“GWC”) than pre-drill expectations and the ‘A Sand’ reservoir was found to have higher quality than in other parts of the field. The interpretation of dynamic data from the well indicates a connected GIIP of 10 – 22 Bscf, which is much lower than the volumetric estimate of 84 Bscf (39 Bscf of which resides within the A Sand), suggesting Well G7 is not effectively draining the area.

This conclusion was corroborated during the Operator’s dynamic modelling work, where history matching required incorporating flow barriers to achieve a pressure match. Furthermore, the current extrapolated recovery factor from existing wells appears at the lower end of comparable analogues, indicating a potential for additional recovery upside.

Sproule ERCE has estimated recoverable volumes associated with a new infill well, combining analyses of initial and long term well performance of wells in the area, analogues review and type-curve approach.

A summary of Contingent Resources attributable to the GMA project is provided in Table 6.4.

Table 6.4: Summary of gross Contingent Resources in the GMA area

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
Grove East Infill	0.0	0.1	0.1	3.8	8.4	15.9	DP

7. Cygnus Field

The Cygnus Field is located approximately 150 km from the Lincolnshire coastline in the Southern North Sea, at the northern end of the Southern Permian basin, 12 km north of the Munro field and 15 km northwest of the Tyne field (Figure 7.1). The water depth is approximately 23 m. Ithaca Energy is the Operator.

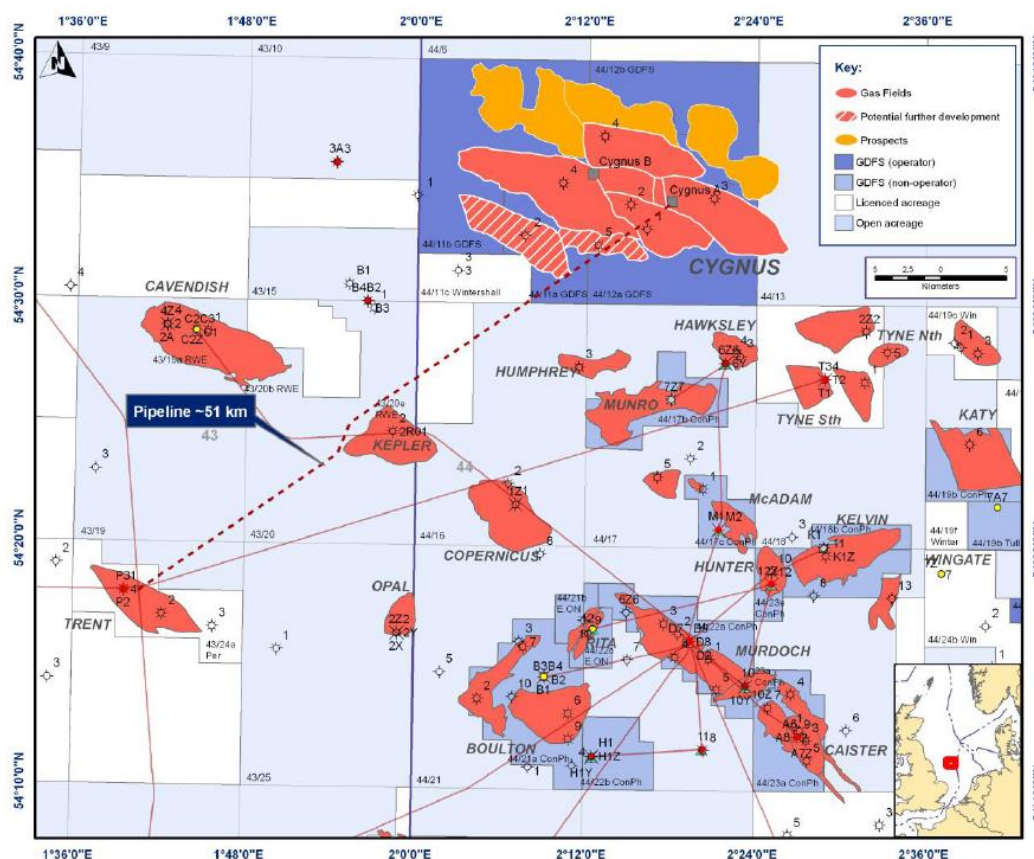


Figure 7.1: Cygnus Field location map

Source: Operator

The Cygnus Field was discovered in 1988. Five appraisal wells were subsequently drilled and gas was tested in the Lower Permian Leman Sandstone Formation and Upper Carboniferous Lower Ketch Member reservoirs. The FDP was approved in 2012.

The field is developed from the Alpha complex (three bridge-linked platforms including one drilling centre) and the Bravo platform (single unmanned platform including a drilling centre, 7 km northwest of the Alpha complex). To date, 13 development wells have been drilled; eight from the Alpha complex and five from the Bravo platform. Gas is exported via a 55 km pipeline to the Esmond Transmission System pipeline, which terminates at the Bacton terminal in the UK.

The Cygnus structure is a series of terraced, tilted fault blocks which have a common gas water contact (Figure 7.2). The Leman Sandstone Formation comprises poor to fair quality sandstones deposited in an arid environment (aeolian sandstones). The Lower Ketch Member, which is present in Fault Blocks 2A, 2B West and 2B East only, is generally better quality than the overlying Leman and comprises poor to good quality sandstones deposited in a fluvial environment.

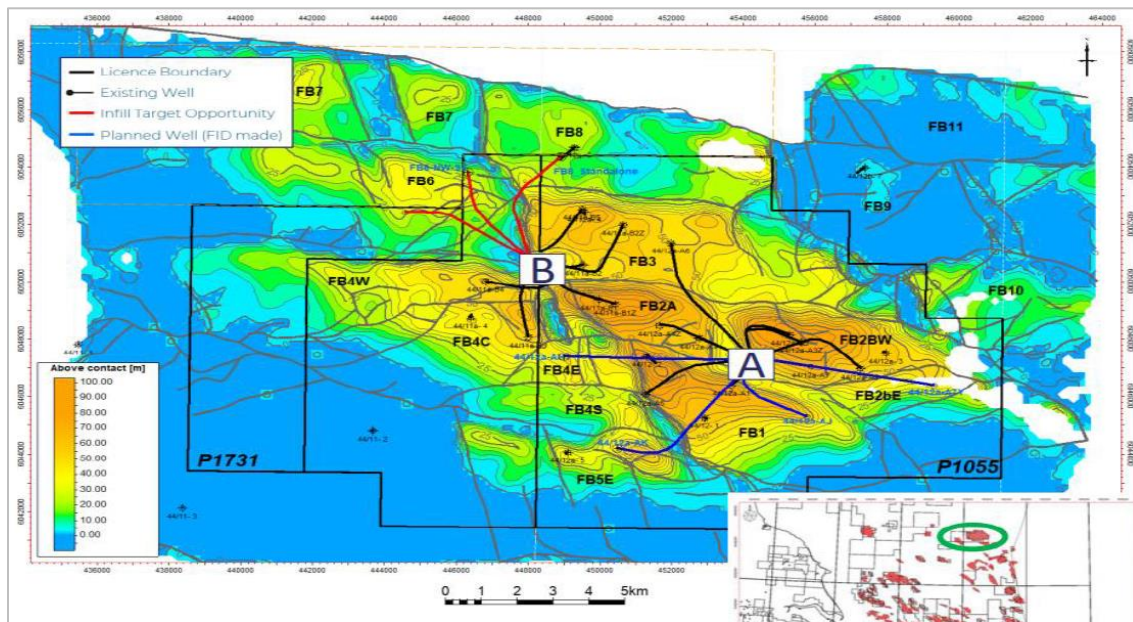


Figure 7.2: Cygnus top Leman depth structure map

Source: Operator

The plateau gas production rate from the field was approximately 300 MMscf/d, and the field has been in decline since mid-2020. In June 2026, 12 wells were online (only Well A7 was offline), producing an average of 164 MMscf/d of gas and 312 bbl/d of condensate (Figure 7.3). Cumulative wellhead production to 30 June 2026 was 732 Bscf of gas and 1.3 MMstb of condensate.

Well A7y was the 12th well to be drilled in the field and came onstream mid-December 2025. The well was drilled into the eastern part of Fault Block 2 (known as the “FB2BE” area), targeting undeveloped gas. The well ceased flowing due to water production in May 2026 having produced 2.4 Bscf gas¹².

Well A8z was the 13th well to be drilled and was brought onstream in April 2026, with initial rates more than 40 MMscf/d. The well encountered good quality reservoir above pre-drill prognosis, and six of the planned seven fractures were placed successfully in the horizontal section.

¹² Between the Effective Date and Issue Date of this report, in August 2026, Well A7 was successfully reinstated at ~30 MMscf/d following the injection of nitrogen into the well.

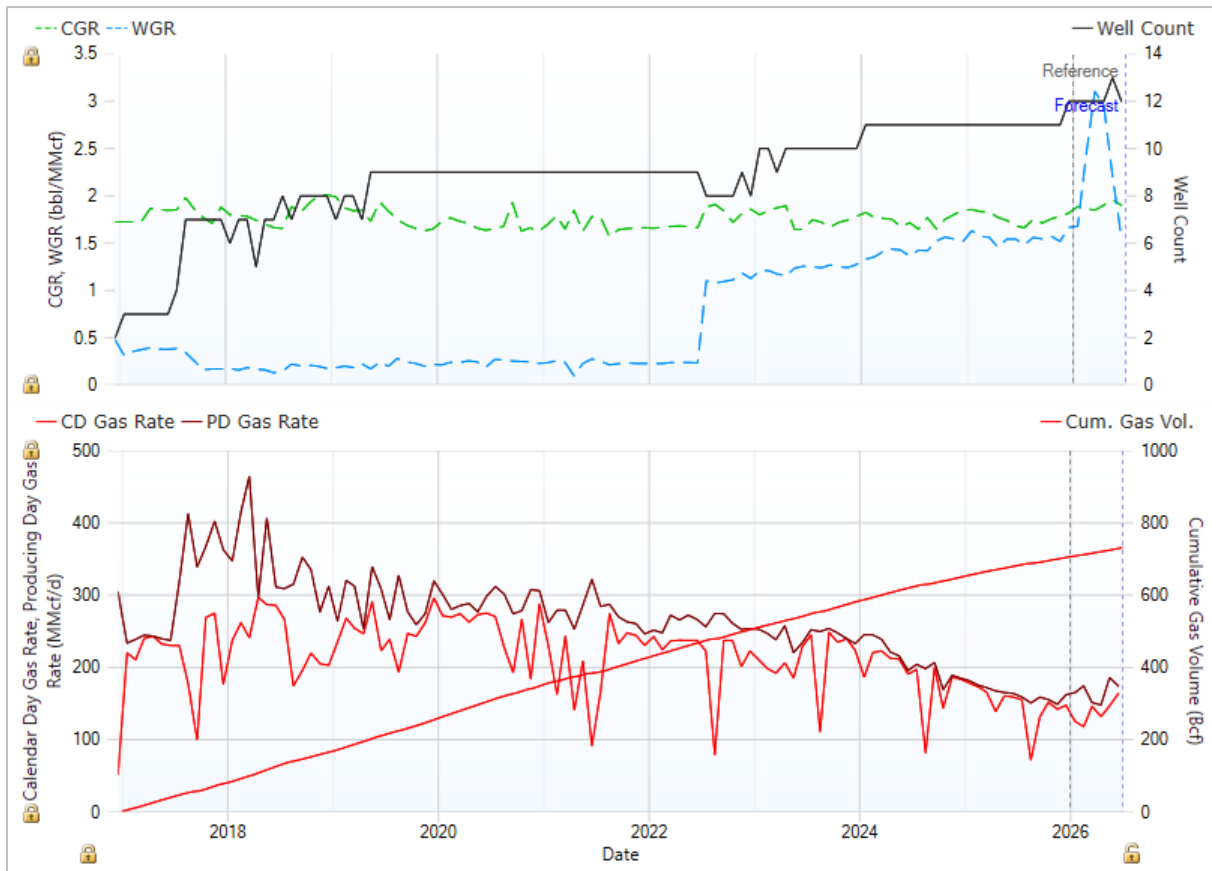


Figure 7.3: Cygnus Field production history

Production from the Cygnus Field requires blending with richer gas at the Bacton terminal to bring the product to sales specification. In the past, this has resulted in periods of restricted field production due to non-availability of blending gas. In August 2025 Ithaca signed an agreement with TotalEnergies to blend with gas from the SEAL pipeline at Bacton which renewed existing agreements through 1 January 2027. Production uptime through 2026 has not been significantly impacted by blend gas restrictions.

In 2025 Ithaca signed two other blending agreements; one combined agreement to October 2028 and one with Harbour to November 2028. These agreements should ensure that Cygnus production will not be restricted by a lack of blend gas in the future.

7.1 Development Plans

Development infill drilling is ongoing on Cygnus. Sproule ERCE include two wells as undeveloped Reserves, with a third well classified as Contingent Resources.

The 14th well on the field is scheduled for first gas in October 2026 and is planned to be drilled into Fault Block 4 East (“FB4E”) as a conventional horizontal well. The well has spudded and drilling is ongoing as at the Effective Date.

The 15th well on the field is scheduled for first gas in March 2027 and is planned to be drilled into Fault Block 5 (“FB5”) as a conventional horizontal well.

The 16th well on the field is planned for late 2027. Various plans have been provided to Sproule ERCE as the Operator is looking at drilling a well into a prospective fault block, Fault Block 6 (FB6), with a fallback option to side-track (or drill a standalone development well) into Fault Block 8 (“FB8”) should the prospective location come in. Sproule ERCE assign Contingent Resources to the FB8 location.

7.2 Estimated Ultimate Recovery

Sproule ERCE’s estimates of the developed EUR of the Cygnus field are based on applying a range of recovery factors to a deterministic estimate of the connected GIIP.

Connected GIIP calculations performed by Sproule ERCE, based on p/Z analysis using shut-in pressures measured in the wells, are shown in Table 7.1. Several of the wells show increasing pressures at the end of the shut-in and in these cases, Sproule ERCE has applied simple Horner extrapolations to obtain a more indicative reservoir pressure. The latest pressure data used in this evaluation were acquired in August 2025 during the annual shutdown. The aggregated connected GIIP, excluding the most recently drilled 13th well (Well A8z), for the field is 1,154 Bscf.

Table 7.1: Dynamic GIIP estimates from production data

Block	Horner GIIP (Bscf)
1	108
2A	188
2B	360
3	323
4	175
Field	1,154

To derive the developed wet gas EUR, Sproule ERCE has applied a recovery factor range (80.0 – 86.5 – 93.0%) to the connected GIIP estimate for the field excluding Block 1 (1,046 Bscf), and applied a lower recovery factor range (30 – 40 – 50%) to the connected GIIP of Block 1 (108 Bscf), where reservoir quality is observed to be poorer.

After reviewing the post-drill results of Well A8z, Sproule ERCE considered its pre-drill TRR estimates (11 – 22 – 38 Bscf) to be reasonable and added these to the developed EUR to derive a total developed EUR range of 881 – 968 – 1,060 Bscf. The range of initial rates used for Well A8z was updated versus pre-drill estimates based on post-drill performance (rate close to pre-drill High Case).

The recovery factor ranges used are based on a review of well productivities, estimates of abandonment pressure, consideration for when wells may cease flowing. These EURs are cross-checked against DCA estimates. Well A7y is considered to not restart production in the Low case.

Execution of a medium pressure (“MP”) compression project was completed in 2022. Trains A and B were switched to MP compression in March and May 2022 respectively. An LP compression project is expected to be executed from October 2027 at the earliest and is dependent on field production rates being below the LP compression gas constraints. The LP compression project will reduce the inlet pressure from 47 barg to 20 barg. The benefit of compression is included in Sproule ERCE’s estimates of developed EUR.

Sproule ERCE has included two further infill wells as Undeveloped Reserves.

The 14th well will be drilled into FB4E, across two segments separated by a graben (Figure 7.4). Analysis of Wells B3 and B4 in FB4 shows that they are connected to the mapped GIIP for the segments they are drilled into, and the Operator plans to target gas that is undrained by the current wells. First gas is planned for October 2026.

Sproule ERCE has reviewed the Operator’s plans and models and estimated a probabilistic range of GIIP for the infill well location using the supplied depth maps, and a range of petrophysical parameters from the nearby wells. Sproule ERCE has probabilistically applied a recovery factor range of 40 – 55 – 70% to generate the range in gas EUR shown in Table 7.2.

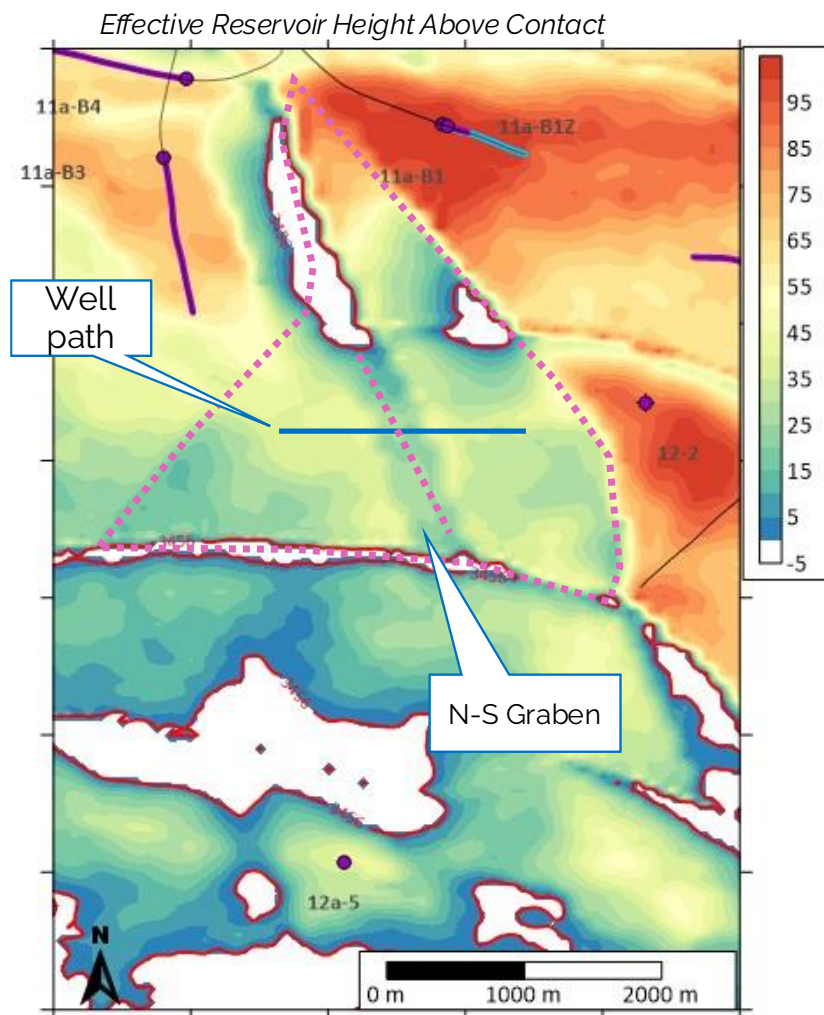


Figure 7.4: Approximate location of infill Well FB4 (14th Well)

Source: Sproule ERCE

The 15th well will be drilled into FB5, targeting a structural high (Figure 7.5). The fault block was discovered by Well 44/12a-5, and the Operator plans to target gas to the east of the discovery well. First gas is planned for March 2027.

Sproule ERCE has reviewed the Operator's plans and models and estimated a probabilistic range of GIIP for the infill well location using the supplied depth maps, and a range of petrophysical parameters from the nearby wells. Sproule ERCE has probabilistically applied a recovery factor range of 40 – 55 – 70% to generate the range in gas EUR shown in Table 7.2.

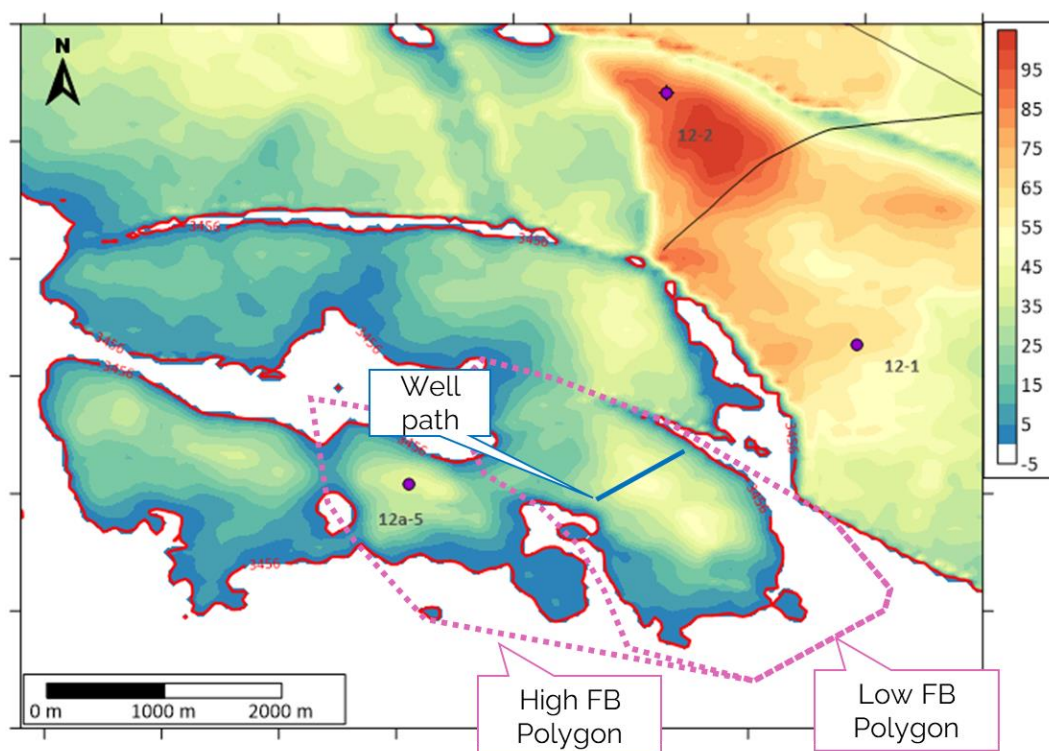


Figure 7.5: Approximate location of infill Well FB5 (15th Well)

Source: Sproule ERCE

Gas production forecasts for Well A8z and the 14th and 15th wells were developed at low, best and high levels of confidence using a type curve approach with a range of initial gas rates based on analogue wells from within the Cygnus Field.

The developed and undeveloped EUR estimates for the field are presented in Table 7.2.

Table 7.2: Cygnus EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Cygnus Developed	Gas	1,199	732	61%	881	968	1,060	81%
Cygnus 14th Well	Gas	70	-	-	18	37	66	53%
Cygnus 15th Well	Gas	40	-	-	14	22	33	54%
Cygnus Total	Gas	1,310	732	56%	913	1,027	1,159	78%

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future

shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 7.3.

Table 7.3: Cygnus production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
Cygnus	85.0	85.0	85.0	85.0	85.0	85.0	85.0

The gross wellhead gas production forecasts for the Cygnus Field assets, for developed and developed plus undeveloped activities, together with the production history since 2022 are presented in Figure 7.6 and Figure 7.7 respectively.

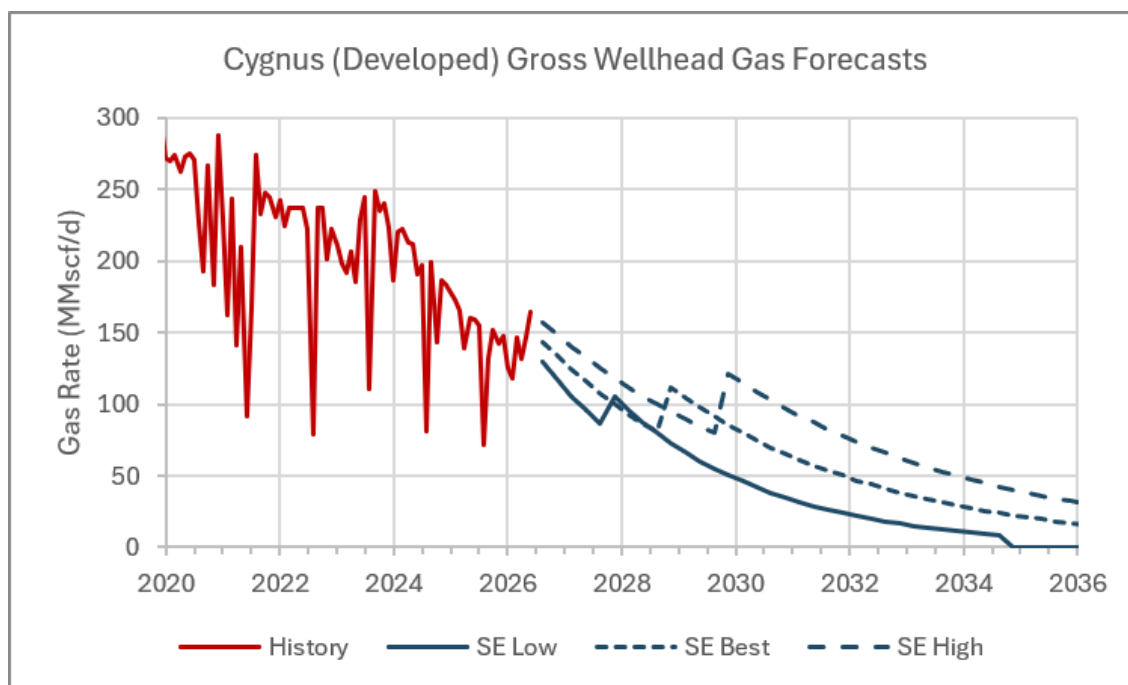


Figure 7.6: Cygnus developed gross wellhead gas production forecasts

SE = Sproule ERCE

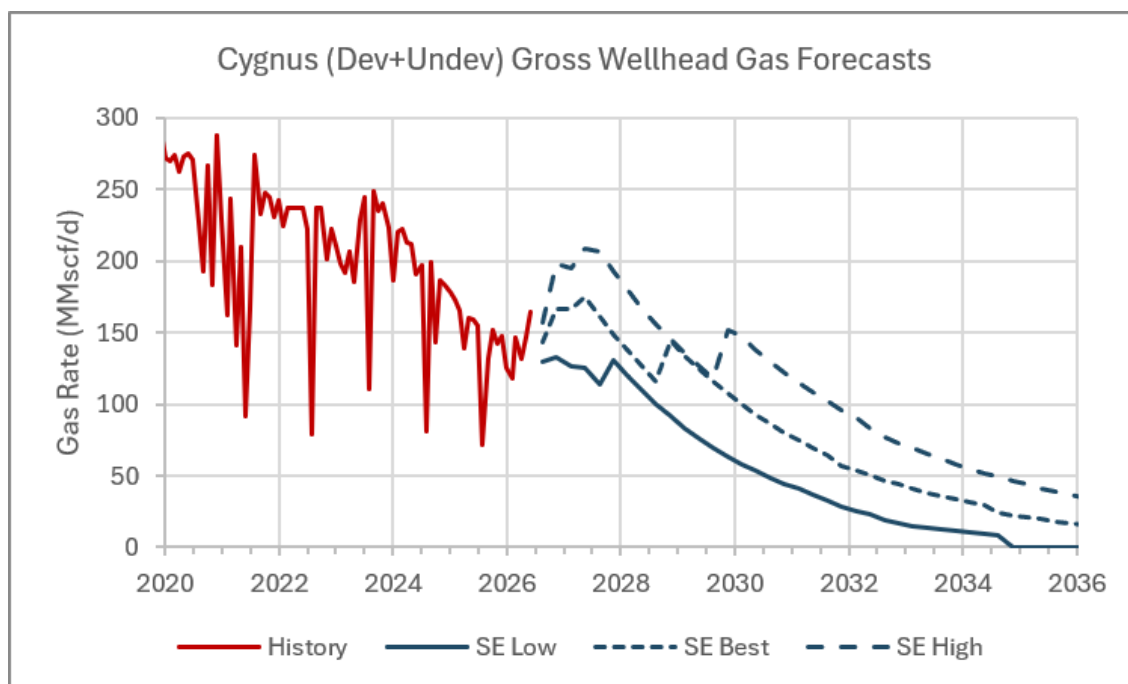


Figure 7.7: Cygnus developed plus undeveloped gross wellhead gas production forecasts

SE = Sproule ERCE

7.3 Facilities and Costs

The Cygnus field is a mature Southern North Sea gas development centred on an offshore platform complex comprising three bridge-linked Alpha platforms: a wellhead and drilling centre, a processing / utilities unit, and a living quarters / central control room platform. The field was originally developed as an 11-well development, with an additional two wells drilled by the Effective Date and two future wells sanctioned by the partnership. Gas is exported via the 215 km ETS pipeline system to the Perenco-operated Bacton Terminal, where it is blended with higher Wobbe Index gas prior to onward processing and distribution.

Future CAPEX for the Cygnus field is primarily associated with the drilling of the two sanctioned development wells in 2026 and 2027. Sproule ERCE has reviewed the Operator's budgeted well cost assumptions and considers them to be reasonable, based on historical actuals and regional benchmark analysis. Additional CAPEX relates to ongoing brownfield facilities maintenance and modification activities.

Sproule ERCE's fixed and variable OPEX for 2026 is broadly in line with the Operator's 2026 WP&B. The variable OPEX stream has been estimated based on the following:

- SEGAL and ETS transportation tariffs, in line with the Operator's assumptions presented in the DSA;
- Bacton treatment charges, assumed to transition to a cost-sharing basis from late 2027 onwards, with the cost share calculated using third-party total Bacton throughput forecasts; and
- Other variable OPEX streams, including NTS transportation, blend gas purchase, and CO₂ emissions costs.

Sproule ERCE carries an ABEX estimate of approximately GBP267 MM, which includes the plugging and abandonment of all wells, together with the decommissioning of associated offshore facilities and export pipelines.

7.4 Reserves

The technical production profiles described in Section 7.2 have been converted to sales profiles. Technical production forecasts include the effect of LP compression. The gas shrinkage, fuel and flare assumptions are 3.0% across the remaining life of the field. The production efficiency assumption of 85% is guided by the field performance in recent years.

The facilities at Bacton are recovering a greater quantity of condensate than is measured at the Cygnus offshore facilities. Sproule ERCE has therefore used the Bacton CGR rather than the wellhead CGR to calculate condensate forecasts. A constant CGR of 3.1 stb/MMscf has been used based on 2025 production data.

Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profiles. A summary of the gross Reserves is presented in Table 7.4 together with CoP dates. There are no 1P Undeveloped Reserves as this scenario did not meet the commerciality criteria for Reserves.

Table 7.4: Cygnus Field gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Cygnus	Developed	0.4	0.6	0.8	121.1	188.0	265.5
	Undeveloped	0.1	0.2	0.3	34.4	62.3	106.9
	Total (Dvpd+Undvpd)	0.5	0.8	1.2	155.5	250.3	372.4
	COP (Total)	Jun-31	Mar-33	Sep-35	Jun-31	Mar-33	Sep-35

7.5 Contingent Resources

Sproule ERCE reviewed one project classified as Contingent Resources. The 16th well on the field is notionally planned for spring 2027. Various plans have been provided to Sproule ERCE as the Operator

is looking at drilling an exploration well into the prospective Fault Block 6 (“FB6”), with a fallback option to side-track (or drill a standalone development well) into Fault Block 8 (“FB8”) should the Prospective location fail.

Sproule ERCE has reviewed the Operator’s plans and models and estimated a probabilistic range of GIIP for the infill well location using the supplied depth maps, and a range of petrophysical parameters from the nearby wells (Figure 7.8). Sproule ERCE has assigned recovery factor estimates (20 – 40 – 60%) and these have been used to probabilistically generate the range in gas EUR shown in Table 7.5. Volumes quoted in the table are for volumes within the P1055 area, the block extends to the North outside the current licence boundary.

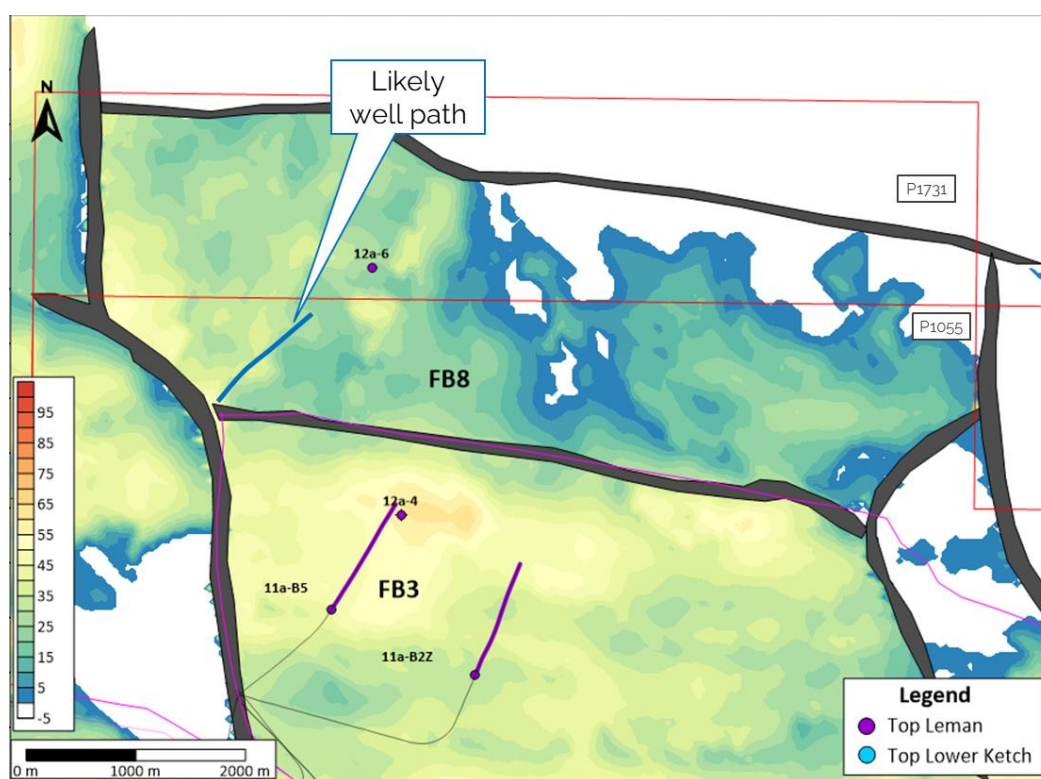


Figure 7.8: Approximate location of infill Well FB8 (16th Well)

Source: Sproule ERCE

Table 7.5: Summary of gross Contingent Resources in the Cygnus Field

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
Well 16	0.0	0.1	0.1	11.5	25.1	46.0	DP

8. Clipper South Field

The Clipper South Field is located in the Southern North Sea, approximately 100 km to the east of the Theddlethorpe Gas Terminal, in shallow water depths of 24 m. The field lies 7 km south of Shell's producing Clipper Field, 15 km west of ConocoPhillips' LOGGS complex and 9 km northeast of the Anglia Field (Figure 8.1). INEOS is the Operator.

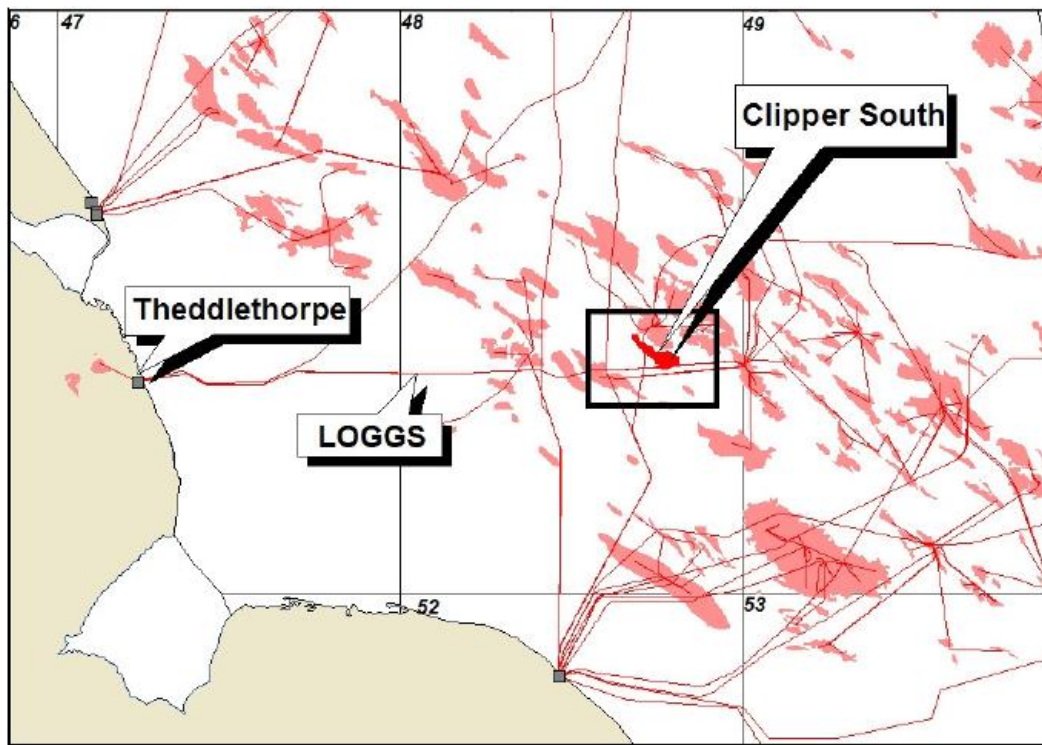


Figure 8.1: Location map of Clipper South gas Field

Source: Operator

The Clipper South Field was discovered by Well 48/19a-3 in 1983 and appraised by Well 48/19C-13 and its sidetrack, Well 48/19C-13Z, in 1992. Clipper South is covered by parts of several 3D seismic surveys, which were merged and reprocessed during 2008. Gas is contained in Leman Sandstone Formation reservoir, comprising a mix of aeolian, fluvial and sandy sabkha sediments. Porosities and permeabilities are, however, relatively poor (approximately 9% and less than 0.1 mD respectively). The structure is a gentle inversion anticline in the footwall of a major northwest-southeast fault which separates Clipper South from the Clipper Field to the north.

The field has been developed with four wells, Wells C1, C2, C3 and C4, drilled from a normally unmanned platform (Figure 8.2). Production commenced from Well C1 in August 2012. The developed part of the field is separated into two areas: the “Core” and “SE” areas. Three of the four wells (Wells C1, C3 and

C4) are drilled in the Core area and these wells align on the same p/Z trend, suggesting they are likely to drain a common volume.

Well C2 is the only well on production in the SE area of the field. The p/Z trend in this well suggests an increasing connected gas volume over time, showing a “bending” effect. This is not uncommon in tight gas reservoirs as lower permeability gas starts to drain to the well as reservoir pressure is depleted. Alternatively, the well could be receiving pressure support from another area of the field.

The connected GIIP of the wells is less than the volumetric field GIIP (321 Bscf versus 487 Bscf, Operator estimates).

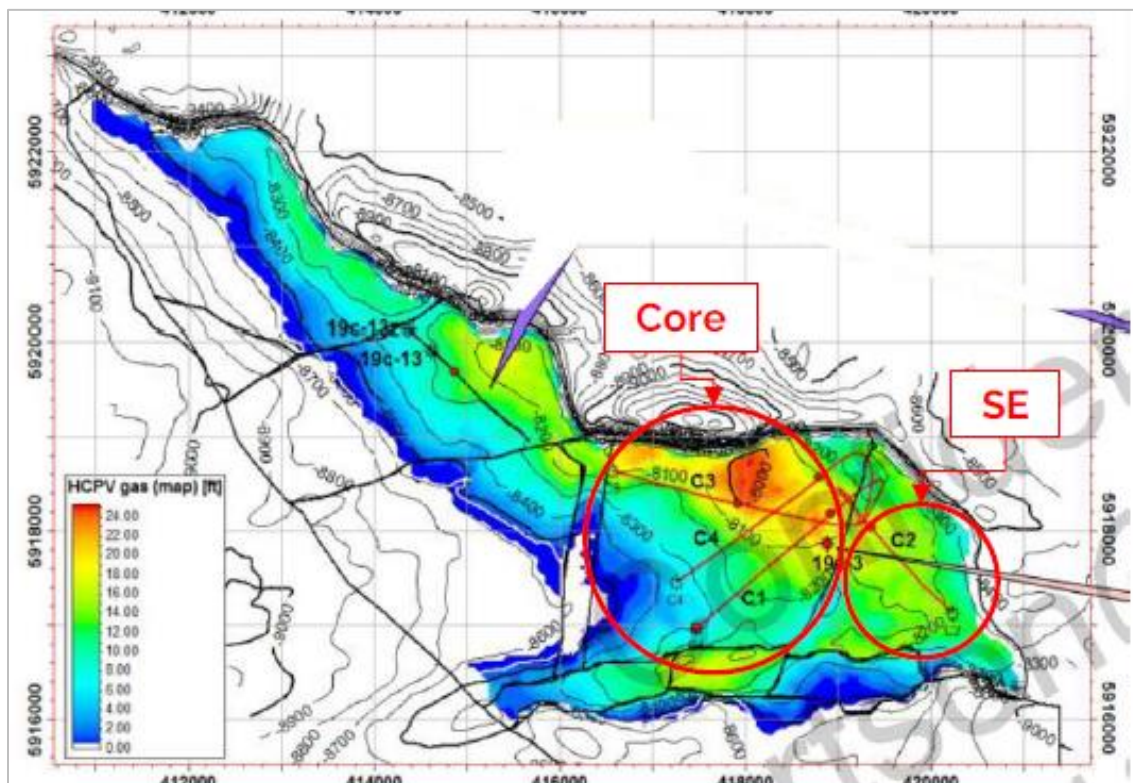


Figure 8.2: Clipper South top structure map

Source: Operator

In 2024 a successful water shut-off intervention campaign was carried out to reduce the producing water-gas ratio (“WGR”) in the wells. This had the largest impact on Well C1, which demonstrates cyclic behaviour due to liquid loading and low reservoir pressure. Well C1 remains a cyclic producer and is kept shut-in for three days each time there is an unplanned trip to ensure adequate gas rate on restart.

Water production allocation to the field is uncertain and WGR testing is carried out periodically. Sproule ERCE was not provided with water production data for the wells.

In June 2026, the field produced an average of 22 MMscf/d of gas and cumulative gas production is 229 Bscf. The Clipper South Field's production history is presented in Figure 8.3.

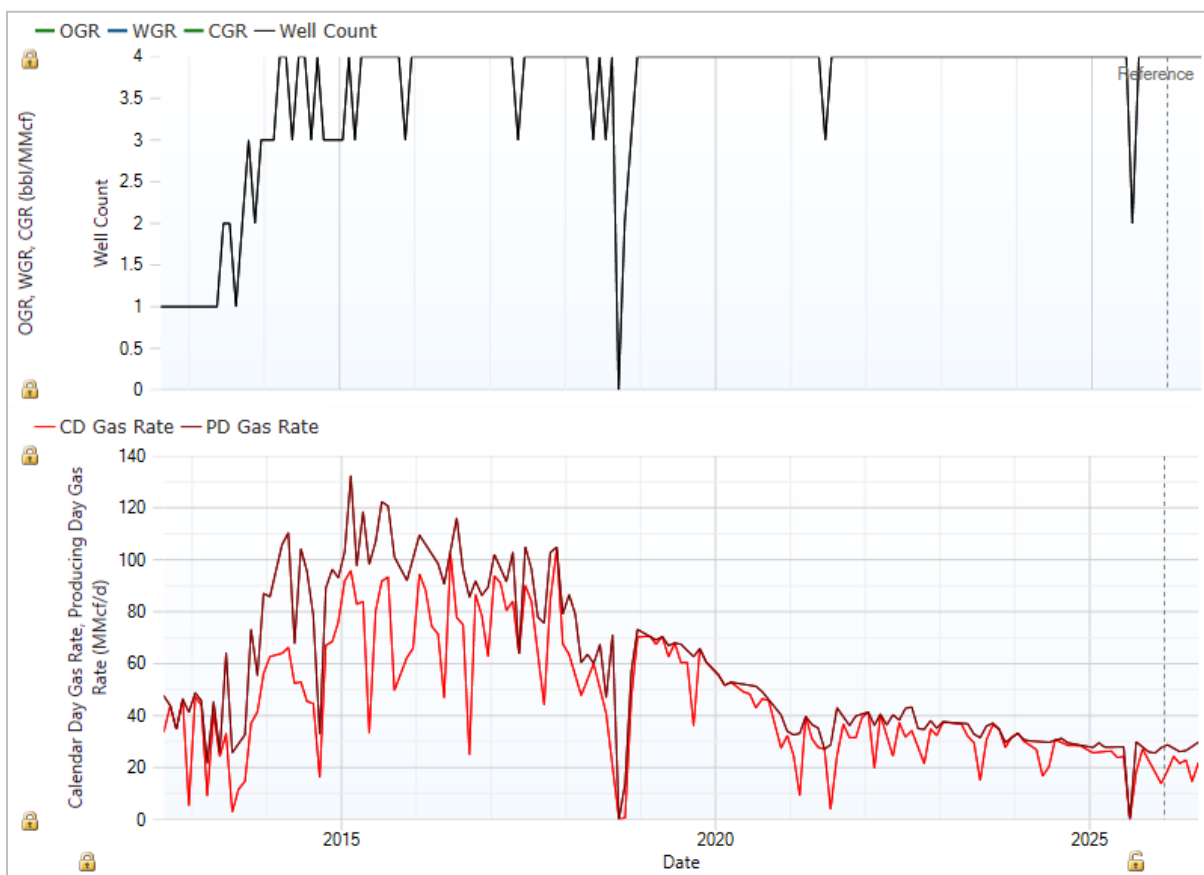


Figure 8.3: Clipper South field production history

8.1 Development Plans

There are no firm development activities planned for the Clipper South field. An infill well opportunity in the undeveloped northwest area of the field is under evaluation by the Operator and has been assessed by Sproule ERCE as Contingent Resources.

8.2 Estimated Ultimate Recovery

Sproule ERCE's estimates of the developed EUR are based on DCA carried out at the well level. Forecasts were made on the producing day rate data, with extrapolations considering gas rates versus time and versus cumulative production. Decline trends are mildly hyperbolic, with 'b' factors of 0.1 – 0.3 used. Minimum gas rates vary between the wells and have been guided by the Operator's network model.

The total EUR estimates and inferred recovery factors against the Operator's best estimate connected GIIP are presented in Table 8.1.

Table 8.1: Clipper South Field EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Clipper South	Gas	321	229	71%	256	265	276	83%

Notes:

1. Recovery factors are calculated using the Operator's PIIP best estimates from material balance methods (connected GIIP).
2. EUR estimates are truncated at end-2036 based on guidance from Serica that the lifespan of the host facilities (at the Clipper Field) are unlikely to extend beyond this point.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 8.2. The planned downtime schedule is based on guidance from the Operator, with 9 days assumed in 2026 and 2027 and 21 days in 2028 (major TAR on Shell's Clipper field). Beyond 2028, 9 days of planned downtime each year are assumed, with 21 days every four years.

Table 8.2: Clipper South production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
Clipper South	89.7	87.5	84.3	87.5	87.5	87.5	84.3

The gross wellhead gas production forecasts for Clipper South, together with the production history since 2020 are presented in Figure 8.4.

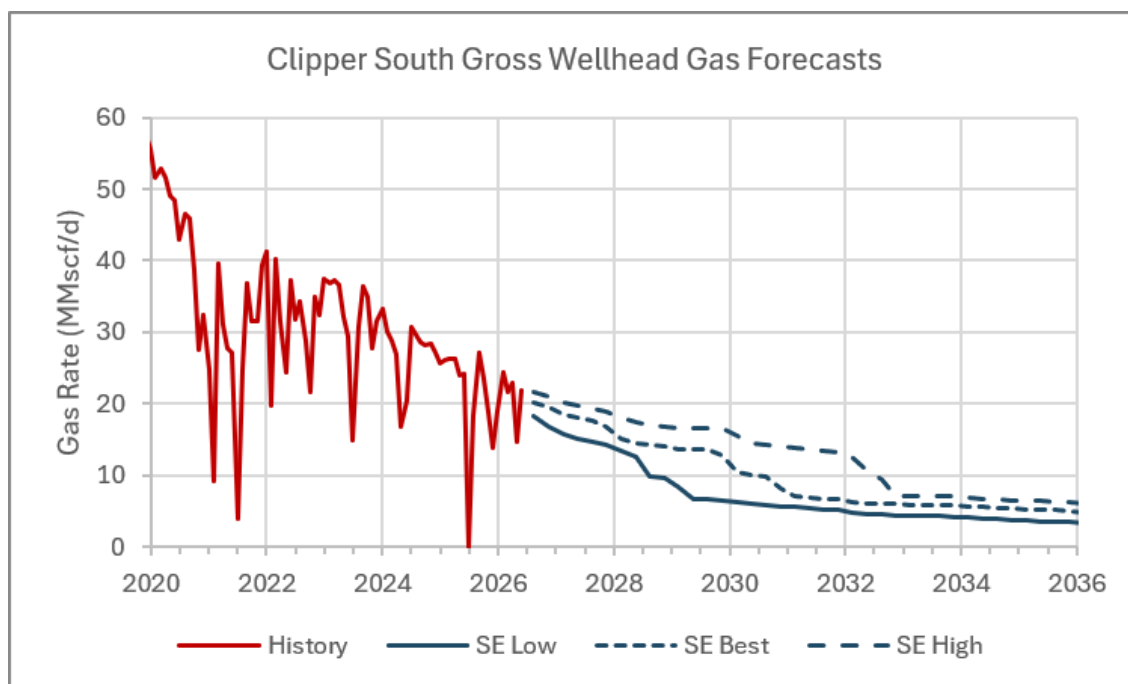


Figure 8.4: Clipper South gross wellhead gas production forecasts

SE = Sproule ERCE

8.3 Facilities and Cost

The Clipper South field is a mature Southern North Sea gas asset produced via a NUI and tied into the wider regional gas export infrastructure. Production was originally routed via the LOGGS complex to the Theddlethorpe Gas Terminal, but is now exported via Shell's Clipper complex to the Bacton Terminal.

There are no forecast Capital activities for the Clipper South Field.

The Operator's 2026 OPEX for the field comprises a fixed OPEX component and a tariff, after which costs transition to a cost-sharing basis. Sproule ERCE has reviewed the Operator's 2026 WP&B and considers the forecast OPEX to be reasonable and broadly consistent with recent historical actuals. Accordingly, Sproule ERCE has adopted the Operator's 2026 budgeted figures. From 2027 onwards, Sproule ERCE has applied a fixed OPEX assumption based on the average of near-term historical actuals, approximating GBP13 MM per annum through field life.

The cost-sharing component comprises Clipper South's allocated share of Bacton, Clipper and Skiff costs, apportioned on a production pro rata basis using the third-party production profiles provided together with Sproule ERCE's Clipper South production forecasts.

Sproule ERCE has reviewed the ABEX assumptions presented by the Operator and considers them to be reasonable for the plugging and abandonment of wells and the decommissioning of associated

facilities and pipelines. Accordingly, these assumptions have been incorporated into the Sproule ERCE forecasts.

8.4 Reserves

The technical production profiles were converted to sales profiles based on data provided by Serica. Wellhead gas was adjusted for fuel consumption, estimated at 8.5% of the wellhead gas production.

There is an agreement in place by which Clipper South has to repay a certain amount of condensate volume back to Clipper. An agreed CGR of 0.95 stb/MMscf is applied to sales gas volumes to calculate Clipper South condensate production forecasts. Sproule ERCE was provided with information regarding the existing condensate balance and this was used to calculate the point at which the balance will be repaid (early 2027) and Clipper South is entitled to start selling condensate volumes.

Reserves were estimated to the earlier of the economic cut-off date or the end of the technical profile. A summary of the gross on block Reserves is presented in Table 8.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 8.3: Clipper South Field gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Clipper South	Developed	0.0	0.0	0.0	12.4	21.2	32.8
	Undeveloped	-	-	-	-	-	-
	Total (Dvpd+Undvpd)	0.0	0.0	0.0	12.4	21.2	32.8
	COP (Total)	Mar-29	Sep-30	Jun-32	Mar-29	Sep-30	Jun-32

Notes:

1. The CoP dates for the Clipper South Field are linked to the CoP date of the host facility (the Clipper Field). However, no information has been provided on the expected CoP date of the Clipper Field and, as such, the CoP dates for the Clipper South Field have been calculated independently.

8.5 Contingent Resources

Sproule ERCE reviewed the Contingent Resources associated with the potential infill well in the northwest area of the field (the “NW infill”). The area has previously been drilled in 1992 by two wells, Well 48/19c-13 and its horizontal sidetrack, Well 48/19c-13z. The results of open hole testing in the horizontal well were below expectation with gas rates of 1-2 MMscf/d achieved, thought to be due to poor reservoir quality. The NW infill well is planned to be a long horizontal with an estimated five hydraulic fractures, drilled through Zones 5 and 4 of the Rotliegend sandstone reservoir.

The Operator is currently updating seismic interpretations on the re-processed seismic data, as well as maturing new static and dynamic models for the area, having previously relied on a 2019 vintage set of models.

After reviewing the Operator's latest work, Sproule ERCE adopted the low and best case estimates as the 1C and 2C Contingent Resources, respectively. The 3C Contingent Resources were calculated assuming a log-normal distribution from the 1C and 2C volumes.

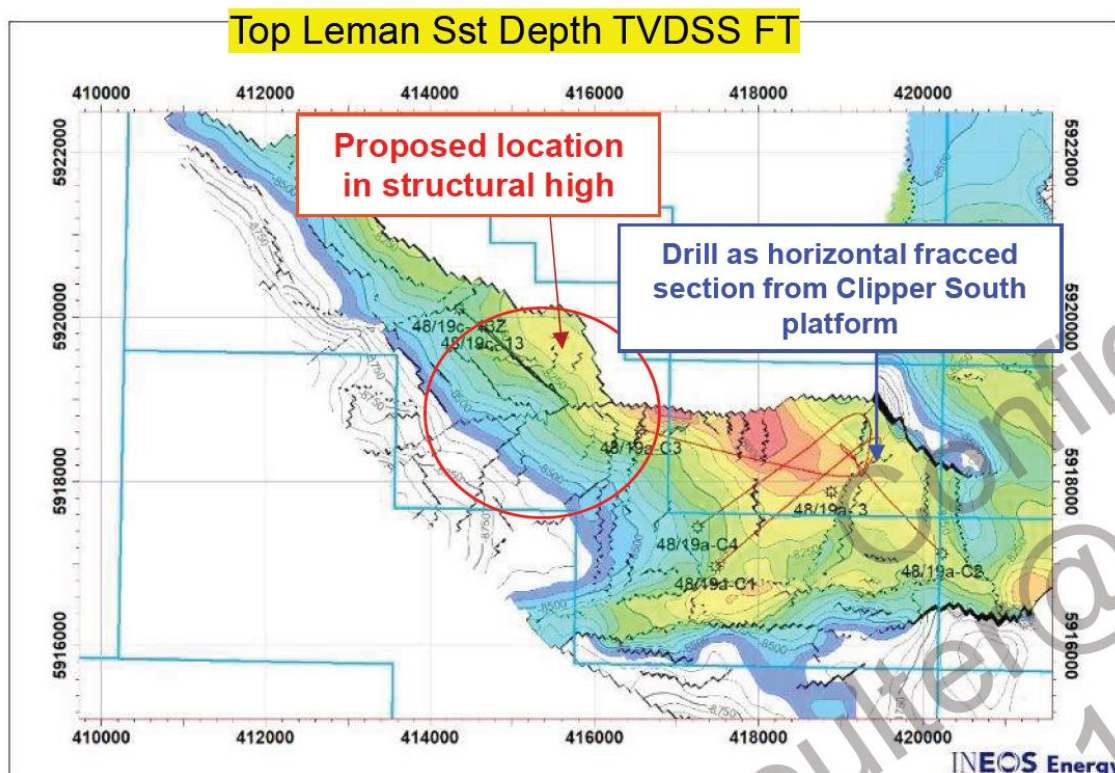


Figure 8.5: NW Clipper South area and proposed 5th well region

Source: Operator

The project is in the Define phase and an FID is scheduled in October 2026 with first gas potentially scheduled in Q4 2027. A summary of Contingent Resources attributable to the NW infill project is provided in Table 8.4.

Table 8.4: Summary of gross Contingent Resources in the Clipper South area

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
NW Infill	0.0	0.0	0.0	19.0	31.0	50.6	DP

9. Galleon Field

The Galleon Field is located within the Sole Pit area of the Southern Gas Basin, in shallow water depths of 25 m (Figure 9.1). The field is located approximately 8 km northeast of the Clipper field and 12 km southeast of the Barque field. The field is operated by Shell.

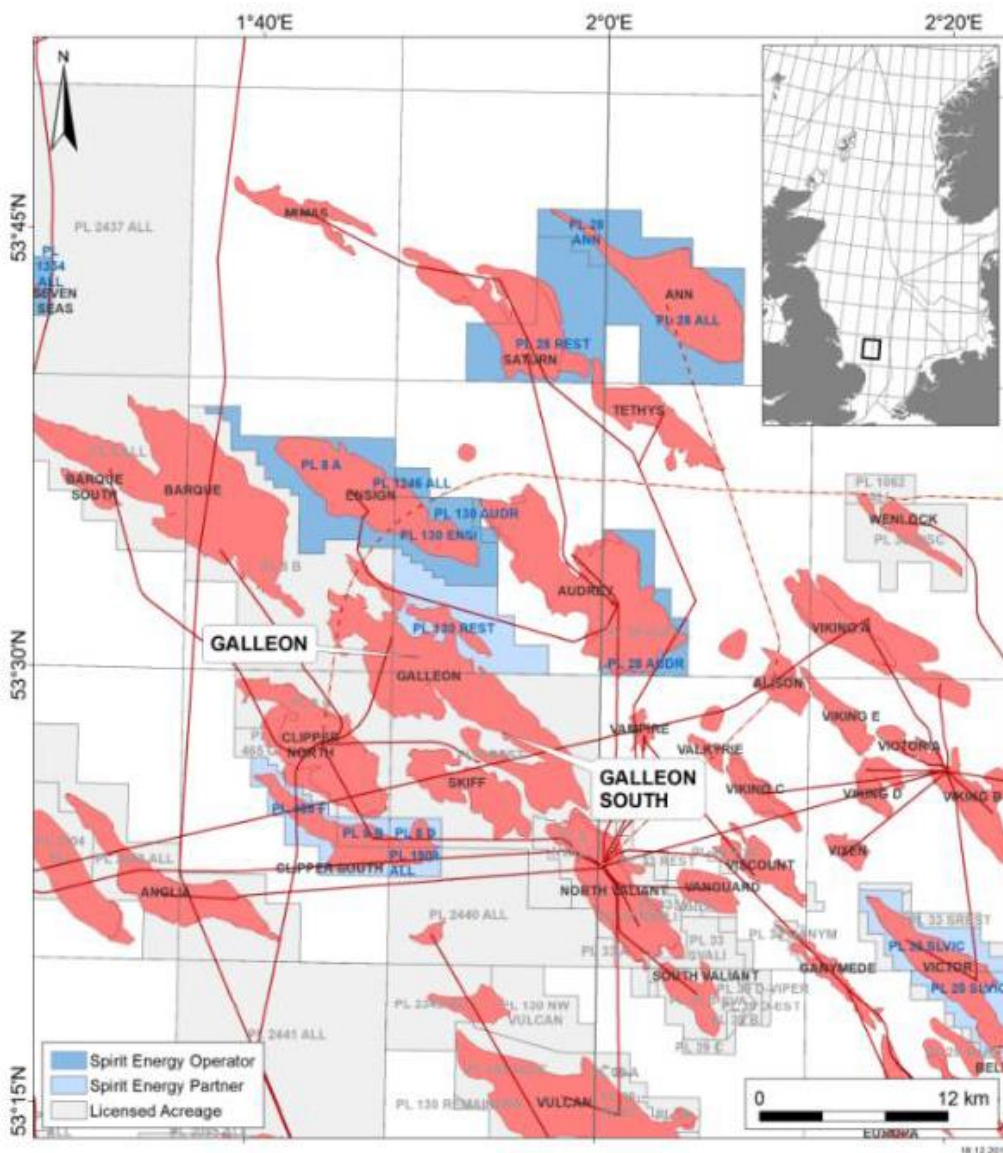


Figure 9.1: Galleon field location map

Source: Operator

The field has an average top reservoir depth of 2,580 m TVDSS and produces lean gas (CGR ~1 stb/MMscf) from the Lower Permian aged Leman Sandstone Formation. The reservoir was deposited in

an aeolian environment and is sub-divided into the Leman A, B and C sands. The reservoir rock is heterogeneous and of poor to medium quality with average porosities and permeabilities of ~8% and ~0.1 mD, respectively.

The field was developed in two stages. Phase I, completed in mid-1994, involved the installation of a minimal facilities platform, Galleon “PN”, in the southeastern part of the field. Production from Phase I commenced in October 1994. Development approval for Phase II of Galleon was granted in December 1996, and Phase II production commenced in November 1998. The second phase accessed the northwest area of the field via a new wellhead platform, Galleon “PG”. A total of 18 wells have been drilled in Galleon, with ten wells on the PG platform and eight wells on the PN platform. Both platforms are tied back to the Barque and Clipper facilities via dedicated pipelines (the Sole Pit Clipper Complex). Gas is exported to Bacton via the Sole Pit gas export line.

In June 2026, the field produced an average of 23 MMscf/d of gas, with negligible condensate recovery, from ten wells (six from the PG platform and four from the PN platform). Cumulative gas production to the as at 30 June 2026 was approximately 829 Bscf. The Galleon Field production history is displayed in Figure 9.2.

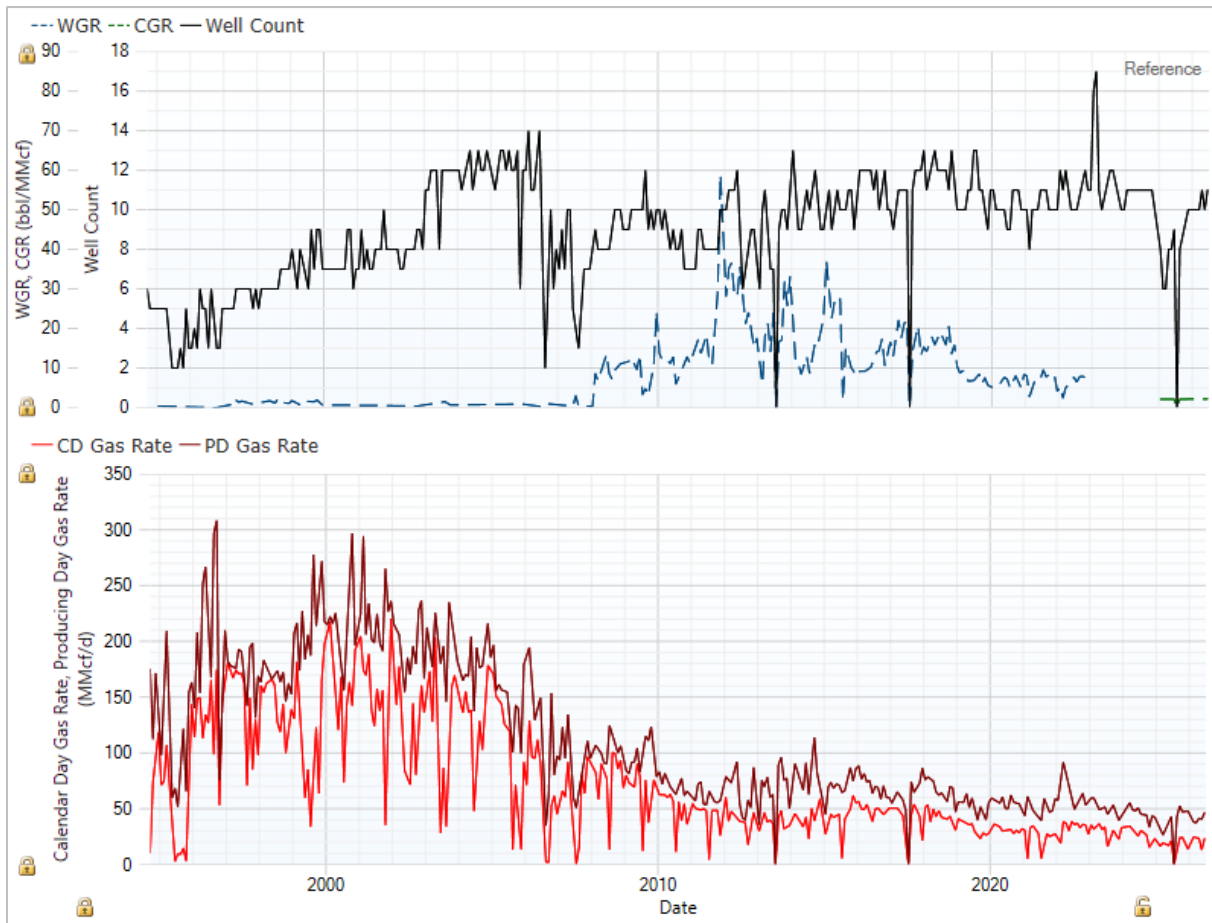


Figure 9.2: Galleon Field gas production history

The Operator has carried out interventions during the last three years to improve and/or sustain production, including subsurface safety valve and control line repair, and recurring water washes. In 2025, a Well and Reservoir Facility Management (“WRFM”) barge campaign achieved short-term performance improvements in two wells. One well, Well PG01, remains suspended with suspected blockage after an unsuccessful topside intervention also performed in 2025.

9.1 Development Plans

The Operator does not have firm plans for further development drilling. A maintenance backlog remains a focus for 2026 on the PN platform, with budgeted initiatives to sustain production reported by the Operator.

Sproule ERCE understands that there are no confirmed plans to further intervene on Well PG01, which is therefore excluded from production forecasts.

9.2 Estimated Ultimate Recovery

Sproule ERCE's EUR estimates were derived using a DCA approach and reconciled with the PIIP proposed by the Operator. The DCA extrapolations have been performed on trends of operating rates versus cumulative gas and versus time. DCA was carried out on a well level basis. The majority of the wells exhibit cyclic production and this has been taken into account by applying individual well efficiencies based on historical data. Two of the wells, Wells PN04 and PN06, currently exhibit stable production. Sproule ERCE has assumed that these wells will begin to cycle in the future, as seen in all other wells. The point at which these wells begin to cycle is based on observations of the flow rates at which other wells began to cycle, approximately 5 MMscf/d.

The total (Developed plus Undeveloped) EUR are presented in Table 9.1. .

Table 9.1: Galleon field EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Galleon	Gas	3,253	827	25%	863	878	897	27%

Notes:

1. Recovery factors are calculated using the Operator's PIIP best estimates presented in the most recent FDP document.
2. EUR estimates are truncated at end-2036 based on guidance from Serica that the lifespan of the host facilities (at the Clipper Field) are unlikely to extend beyond this point.

Sproule ERCE has applied forecasts of production efficiency to the wellhead potential forecasts. Forecasts of production efficiency consider recent historical operating efficiency as well as planned future shutdowns and maintenance. A summary of the production efficiency assumptions is presented in Table 9.2. A major TAR lasting ~30 days is scheduled every four years; the next one being in 2029. For cycling wells, an additional well efficiency is incorporated which ranges from 20-65%.

Table 9.2: Galleon production efficiency forecast

Asset	Production Efficiency (%)						
	H2 2026	2027	2028	2029	2030	2031	2032
Galleon	87.0	87.0	87.0	79.0	87.0	87.0	87.0

The gross wellhead gas production forecasts for Galleon, together with the production history since 2020 are presented in Figure 9.3.

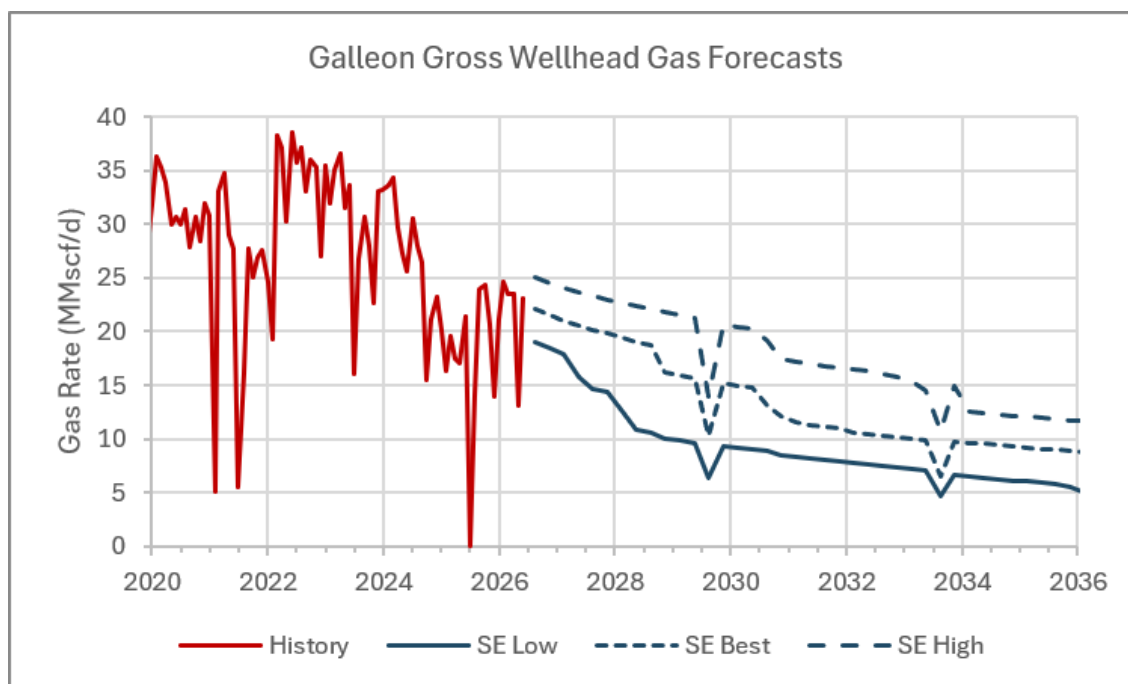


Figure 9.3: Galleon gross wellhead gas production forecasts

SE = Sproule ERCE

9.3 Facilities and Cost

There is no near-term CAPEX forecast for the Galleon field based on data provided by the Operator.

The field OPEX comprises fixed OPEX, tariff, and UK ETS emissions costs. Sproule ERCE has aligned with the Operator's 2026 fixed OPEX assumptions as presented in the 2026 WP&B. While the Operator's 2026 budget does not include barge or WRFM activity, Sproule ERCE has included an allowance within its forward forecast to reflect the potential requirement for such activities in future years, consistent with historical operating patterns.

Sproule ERCE has assumed a tariff unit cost of GBP0.97 per Mscf. In addition, Sproule ERCE has applied its UK ETS price deck to the budgeted emissions presented in the latest TCM pack provided.

Sproule ERCE carries an ABEX estimate of approximately GBP92 MM, which includes the plugging and abandonment of all wells, together with the decommissioning of associated offshore facilities and export pipelines.

9.4 Reserves

The technical production profiles were converted to sales profiles based on data provided by Serica. Wellhead gas was adjusted for fuel consumption, estimated at 6% of the wellhead gas production.

Forecasts of condensate production were estimated using a CGR of 0.9 stb/MMscf. Reserves were estimated to the earlier of the economic cut-off date or the end of the technical profile. A summary of the gross Reserves is presented in Table 9.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Serica has advised that the latest CoP of the Galleon Field is end-2036 and this limit has been used to truncate the 3P Reserves.

Table 9.3: Galleon Field gross Reserves with CoP dates

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Galleon	Developed	0.0	0.1	0.1	17.7	46.4	61.4
	Undeveloped	-	-	-	-	-	-
	Total (Dvdp+Undvdp)	0.0	0.1	0.1	17.7	46.4	61.4
	COP (Total)	Sep-30	Dec-36	Dec-36	Sep-30	Dec-36	Dec-36

Notes:

1. The CoP dates for the Galleon Field are linked to the CoP date of the host facility (the Clipper Field). However, no information has been provided on the expected CoP date of the Clipper Field and, as such, the CoP dates for the Galleon Field have been calculated independently.

9.5 Contingent Resources

Whilst infill opportunities exist within the field, Serica does not consider these mature enough to be assessed by Sproule ERCE.

10. Eris Field

The Eris Field is located in Blocks 47/8c, 47/9b, 47/9c and 47/3h on the northwest margin of the Southern Permian gas basin and on the edge of the Sole Pit basin at its western margin, 100–150 km east of the East Anglia coast in relatively shallow water depths of 35–40 m (Figure 10.1). The field is ~7 km northwest of the Mercury field and 5 km west of the Ceres field. As at the Effective Date the Operator was Spirit Energy and operatorship is set to transfer to Serica on completion of the Spirit Transaction.

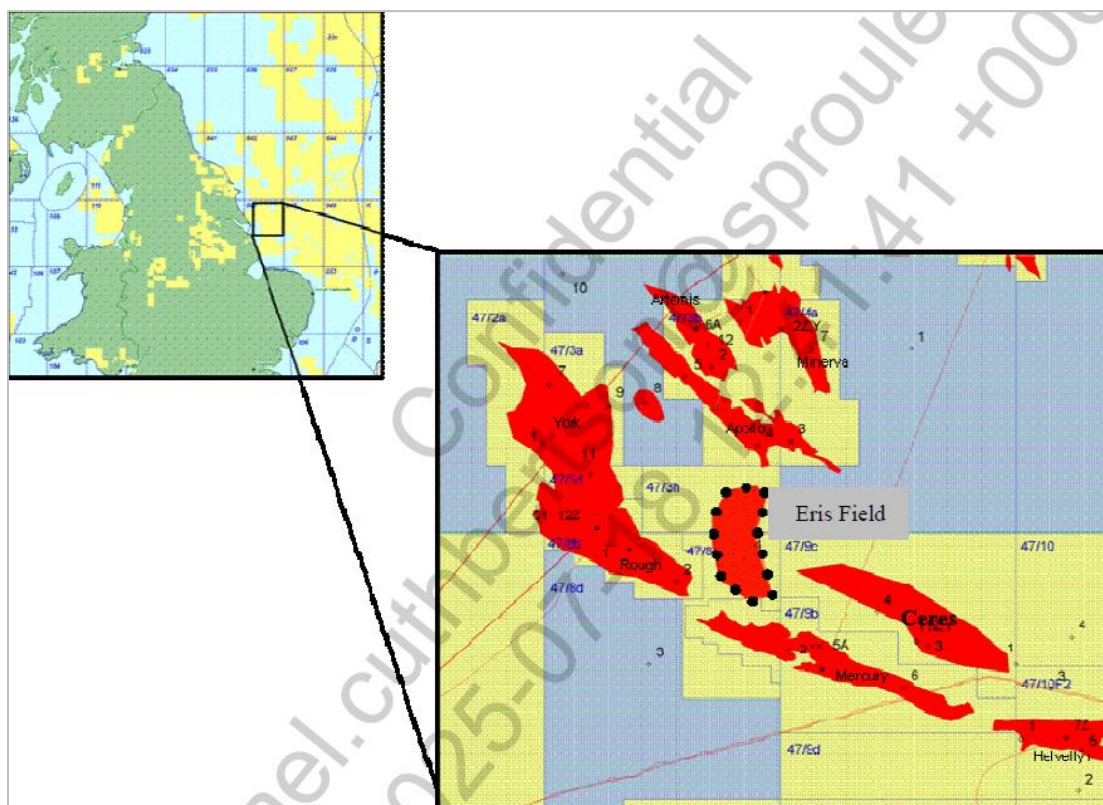


Figure 10.1: Eris field location map

Source: Operator

The Eris Field was discovered in August 2007 by Well 47/8c-4, which encountered 65 m of Rotliegend sandstone in two separate fault blocks, the Main block and the North block (Figure 10.2). The well was tested at stabilised gas rates of 55 MMscf/d, constrained by facilities. The well was suspended and later used as the single gas production well in the field.

The field was jointly developed with the neighbouring Ceres Field, also operated by Spirit Energy as at the Effective Date and set to transfer to Serica on completion of the Spirit Transaction, as a single subsea well, tied back 8.5 km with a 6" production flowline to the Mercury manifold and from there to Neptune and onshore to Dimlington via the Cleeton platform. First gas was achieved in 2010.

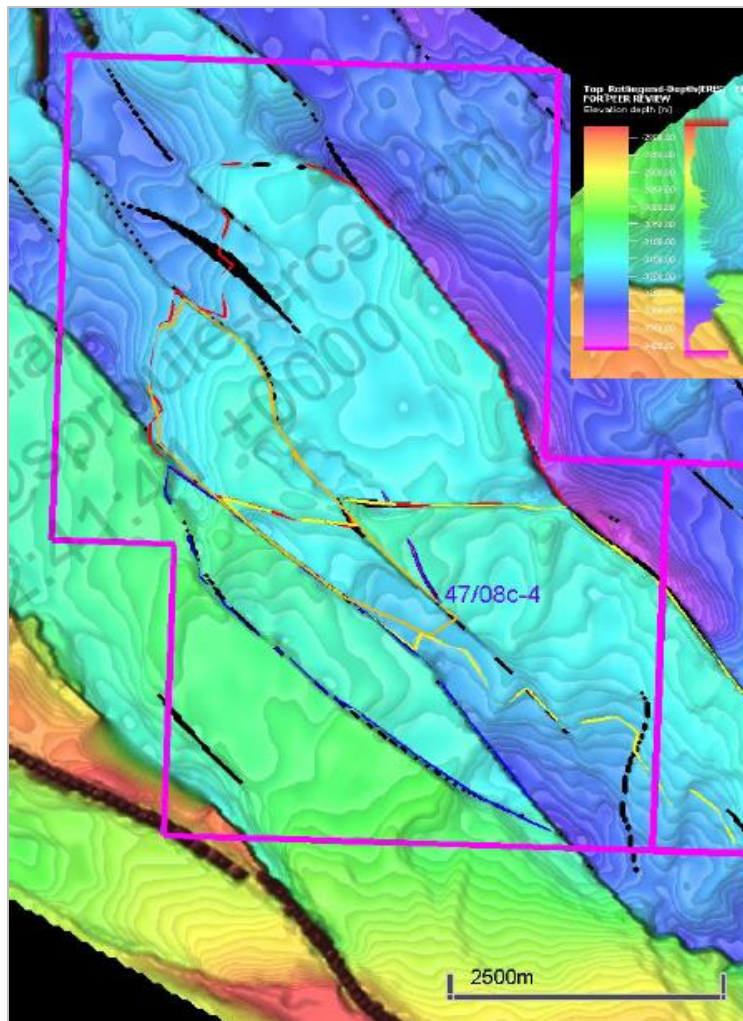


Figure 10.2: Eris Field top structure map

Source: Operator

Historically, production from the field was intermittent to reduce backout of production at the Mercury Field. A back-out agreement with Mercury has meant that in the past Eris has paid Mercury for backed-out gas, followed by subsequent repayments. Sproule ERCE understands that paybacks have been completed, and these will not affect future revenue forecasts.

In late November 2025, production from Eris suddenly dropped from 5-8 MMscf/d to <2 MMscf/d. Since early January production has been slowly ramped up to almost 3 MMscf/d, although there is uncertainty in the rate due to unconfirmed allocation between the Mercury, Eris and Ceres Fields. The Operator has no explanation for the sudden drop in production and investigations are ongoing.

The neighbouring Ceres field was unable to return to production following a shutdown in June 2026 and the field partners are currently exploring future options, one of which is to declare CoP.

In June 2026, the field produced an average of 2.0 MMscf/d of gas, with 2 bbl/d of condensate (Figure 10.3). Cumulative production to 30 June 2026 was 68 Bscf of gas and 0.02 MMstb of condensate.

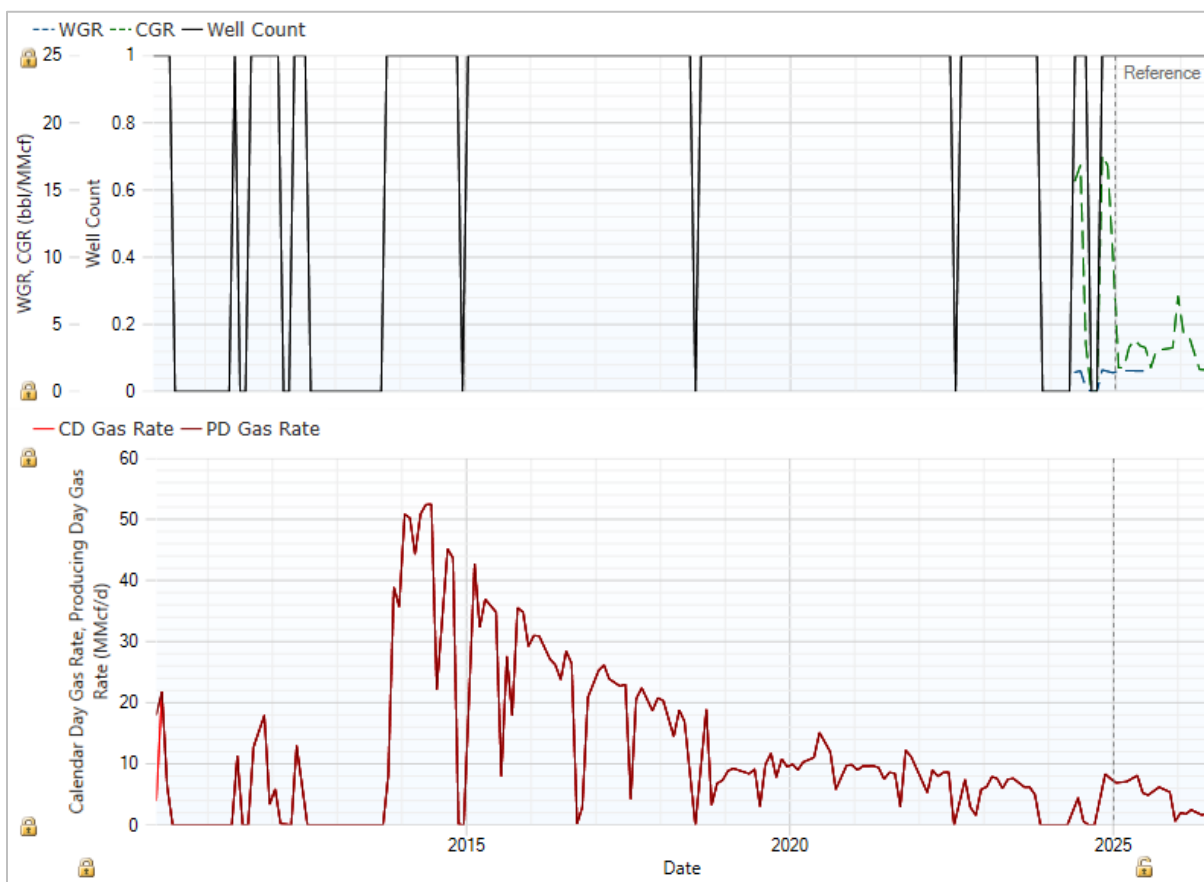


Figure 10.3: Eris Field production history

10.1 Development Plans

There are no plans for further development. The field is approaching CoP and the Operator's estimate of the latest possible CoP date is end of 2029.

10.2 Estimated Ultimate Recovery

The Eris field EUR was estimated based on performance analysis with DCA carried out using extrapolation of trends of gas calendar rates versus time and versus cumulative production. Sproule ERCE has assumed that production will not recover to pre-December 2025 levels and instead will remain ~2-3 MMscf/d with low decline.

Condensate forecasts are based on applying a constant CGR of 3.3 stb/MMscf at all levels of confidence. The total EUR estimates are presented in Table 10.1.

Table 10.1: Eris field EUR estimates and recovery factors

Asset / Field	Hydrocarbon	PIIP (Best estimate)	Cum. Prod. (Bscf) at 30 Jun 2026	RF to date	EUR (Bscf)			EUR Best Est. RF
		(Bscf)	(Bscf)		Low	Best	High	
Eris	Gas	85	68	80%	70	75	84	88%

Notes:

1. Recovery factors are calculated using the Operator's latest PIIP best estimate derived volumetrically.

Sproule ERCE has not explicitly applied production efficiency assumptions in the Eris field because production forecasts were generated on a calendar rate basis.

The gross wellhead gas production forecasts for Eris, together with the production history since 2020 are presented in Figure 10.4.

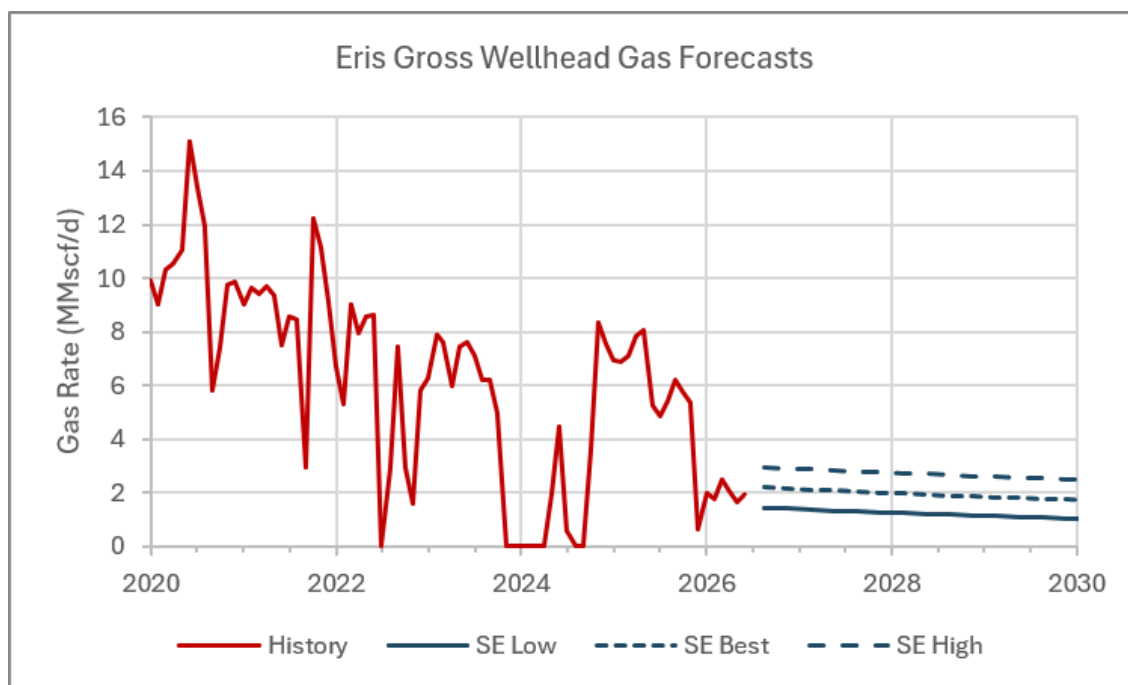


Figure 10.4: Eris gross wellhead gas production forecasts

SE = Sproule ERCE

10.3 Facilities and Cost

There is no future CAPEX forecast for the Eris field.

The field OPEX comprises fixed OPEX, cost-sharing, tariff, and CO₂ emissions costs. Sproule ERCE's fixed OPEX forecast is in line with the Operator's latest WP&B estimates. The cost-sharing component comprises the ECA cost share and Eris' allocated share of Mercury, Neptune and ECART costs. Sproule ERCE has relied on the latest cost share forecast provided by the Operator.

The tariff component comprises the POSA tariff together with additional third-party tariffs. Sproule ERCE has adopted the Operator's tariff assumptions in accordance with the latest forecast provided to Sproule ERCE.

Sproule ERCE understands that, as part of the Spirit Transaction, Spirit Energy will retain all abandonment liability for the operated assets in the portfolio, including the Eris field, up to an agreed cap. The Operator's estimates of ABEX are within the agreed cap and therefore ABEX has been excluded in the calculation of NPV.

10.4 Reserves

The technical production profiles described in Section 10.2 were converted to sales profiles. Gas produced at wellhead is reduced by 0.3% for fuel consumption.

Sproule ERCE does not attribute any Reserves to the Eris field after testing commerciality under PRMS.

10.5 Contingent Resources

Future production from the existing well, which was found to be uneconomic at the 2P level of confidence, has been classified as Contingent Resources. Contingent Resources for future production are truncated at 31 December 2029, which is the Operator's assumption of the latest possible CoP date. A summary is provided in Table 10.2.

Table 10.2: Summary of gross Contingent Resources in the Eris Field

Project	Oil+Condensate (MMstb)			Gas (Bscf)			Sub-class
	1C	2C	3C	1C	2C	3C	
NFA Production	-	-	-	1.6	2.5	3.5	DP

11. Economic Evaluation

Sproule ERCE has reviewed the economic model supplied by Serica.

The CoP dates were determined at the 1P/2P/3P developed and 1P/2P/3P developed plus undeveloped levels of uncertainty. These were based on the UK fiscal regime, production and cost profiles generated by Sproule ERCE and several economic assumptions listed below.

The ELT was carried out at the hub or field level. Forecasts were prepared on a quarterly basis and, in accordance with PRMS guidelines, the CoP date used to estimate Reserves was defined as a) the end of the last three month period in which the maximum cumulative operating cashflow occurs; b) the end of the technical field life; or c) the end of the licence period, whichever is projected to occur soonest. All the assets reviewed are in the North Sea, and the interests are in licences that are routinely extended to the economic limit; therefore, reserves reported herein were not limited by licence dates and were projected to the economic limit or the technical abandonment limit, unless business decisions by the operators or working interest holders defined an earlier point of time for abandonment.

The commerciality of the undeveloped Reserves for each field was tested on an after-tax basis as required under PRMS. In line with PRMS, undeveloped Reserves are included if the incremental value associated with the project is NPV10 positive at a 2P level on an after-tax basis; however, if the project 1P is NPV0 negative, only 2P and 3P undeveloped Reserves are assigned.

The results are presented on a 100% gross basis, a Company Working Interest basis (10%) and a Company Net Entitlement basis as at the Effective Date of 30 June 2026.

11.1 Petroleum Fiscal Terms

The following fiscal terms apply to the ring-fenced oil and gas profits:

- Corporate Tax ("CT") Rate of 30%
- Supplementary Charge Tax ("SCT") Rate of 10%
- Energy Profits Levy ("EPL") of 38%, applied on top of CT and SCT
- all investment allowances and carry back/forward mechanisms as applicable.

11.2 Commercial Assumptions

- Capital and operating costs have been determined in 2026 real terms and inflated at a 2.0 per cent annual inflation rate
- An exchange rate of GBP1.00/USD1.32 is used in 2026, and GBP1.00/USD1.35 from 2027.
- An exchange rate of GBP1.00/EUR1.16 is used in 2026, GBP1.00/EUR1.14 in 2027 and GBP1.00/EUR1.13 from 2028.

11.3 Commodity Price and Carbon Allowance

Sproule ERCE's forecasts, dated 30 June 2026, of Brent crude oil and NBP natural gas prices were used for the evaluation. These are presented in Table 11.1. The table shows prices in 2026 real terms, and these are subject to annual inflation of 2.0% to determine nominal (money of the day) prices. Where appropriate, Sproule ERCE has applied a differential related to crude quality in price or gas heating content, to Brent or NBP prices, respectively.

Sproule ERCE has also included carbon pricing in its Reserves assessment. Where relevant, Sproule ERCE has reviewed the emissions profiles provided by the Operator for emissions expected to arise during hydrocarbon production operations and covered under the UK ETS. The associated future emissions costs have been estimated by applying Sproule ERCE's forecast UKA price deck to the forecast emissions profiles. Sproule ERCE's commodity price and UKA forecasts are presented in Table 11.1.

Table 11.1: Sproule ERCE Commodity Price Forecasts as at 30 June 2026

	Brent Crude Oil Price	NBP Gas Price	UKA Price
Year	\$US/bbl	p/therm	GBP/tonne
2026	75.00	106.10	57.15
2027	73.53	87.10	58.87
2028	72.09	71.20	60.60
2029	72.09	71.20	60.42
2030	72.09	71.20	61.38
2031	72.09	71.20	62.21
2032	72.09	71.20	63.15
2033	72.09	71.20	64.20
2034	72.09	71.20	65.35
2035+	72.09	71.20	66.58

Notes:

1. Brent crude oil price, NBP gas price and UKA price forecasts are based on the Sproule ERCE 30 June 2026 price forecast and are presented in real (2026) terms.
2. Catcher assets trade at a US\$2.50 per barrel discount to Brent.
3. The assets included in the Spirit Energy transaction trade at a 4.08 p/therm discount to NBP.
4. NGLs are assumed to be sold at a 30% discount to Brent.

11.4 Net Present Values

The before tax NPV estimates attributable to Serica, on an asset-level basis, at discount factors of 0%, 5%, 10%, 15% and 20%, as at 30 June 2026 are presented in Table 11.2.

Sproule ERCE has calculated after tax NPV estimates attributable to Serica, on a corporate entity basis, at discount factors of 0%, 5%, 10%, 15% and 20%, as at 30 June 2026. The after tax NPVs take into account Serica's historical tax balances in each entity, which were provided by Serica. The corporate entity-level before and after tax NPVs are presented in Table 1.8 in the Executive Summary.

Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as Sproule ERCE's opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas resources are estimates only and there is no guarantee that the estimates will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report.

Table 11.2: Asset level before tax net NPV of the total Reserves

(attributable to Serica as at 30 June 2026)

Asset	Scenario	Before tax NPV (US\$MM) at discount rates of:				
		0%	5%	10%	15%	20%
GLA	1P	-185	-111	-60	-25	0
	2P	-193	-125	-76	-41	-16
	3P	-200	-140	-96	-63	-38
Catcher	1P	-28	-18	-11	-5	-1
	2P	-3	10	18	22	25
	3P	29	37	41	43	43
GEAD	1P	-42	-33	-26	-21	-17
	2P	-35	-23	-15	-10	-6
	3P	-22	-7	2	6	8
Chiswick	1P	34	33	32	31	30
	2P	60	57	54	51	49
	3P	75	71	67	64	61
Grove	1P	4	4	4	4	4
	2P	11	10	10	10	9
	3P	20	19	18	18	17
Kew	1P	3	3	3	3	3
	2P	6	6	6	5	5
	3P	7	7	7	6	6
J3C	1P	0	0	0	0	0

Asset	Scenario	Before tax NPV (US\$MM) at discount rates of:				
		0%	5%	10%	15%	20%
	2P	0	0	0	0	0
	3P	1	1	0	0	0
Cygnus	1P	57	65	69	71	71
	2P	157	156	151	145	138
	3P	279	264	245	227	210
Clipper South	1P	6	7	8	9	10
	2P	16	17	18	18	18
	3P	29	29	28	28	27
Galleon	1P	-6	-2	0	2	3
	2P	1	6	8	9	9
	3P	14	14	14	14	13
Eris	1P	-	-	-	-	-
	2P	-	-	-	-	-
	3P	-	-	-	-	-
Total	1P	-156	-52	19	68	102
	2P	18	114	173	210	232
	3P	231	295	327	343	348

Notes:

1. Individual values may not add up to the reported totals due to rounding.

Appendix 1: Gross Production and Cost Forecasts

This appendix includes detailed forecasts of Sproule ERCE's gross production and costs for each asset.

Table A - 1: GLA 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.2	21.8	0.4	0.8	(22.6)	CoP 0	-
2027	0.2	17.8	0.3	-	(23.7)	CoP 1	166.3
2028	0.2	16.2	0.3	-	18.9	CoP 2	166.3
2029	0.1	13.6	0.2	-	26.4	CoP 3	166.3
2030	0.1	10.7	0.2	-	28.0	CoP 4	-
Total (MMstb / Bscf / MM GBP)	0.3	25.3	0.5	0.8	27.1		499.0

Table A - 2: GLA 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.3	25.1	0.5	0.5	(13.7)	CoP 0	-
2027	0.2	21.1	0.4	-	(6.4)	CoP 1	166.3
2028	0.2	20.0	0.4	-	35.8	CoP 2	166.3
2029	0.2	17.4	0.3	-	43.9	CoP 3	166.3
2030	0.2	14.2	0.3	-	44.5	CoP 4	-
Total (MMstb / Bscf / MM GBP)	0.3	31.2	0.6	0.5	104.0		499.0

Table A - 3: GLA 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.3	28.5	0.5	0.6	(3.2)	CoP 0	-
2027	0.3	24.5	0.4	-	11.2	CoP 1	166.3
2028	0.3	24.0	0.4	-	53.8	CoP 2	166.3
2029	0.2	21.6	0.4	-	63.0	CoP 3	166.3
2030	0.2	18.2	0.3	-	63.2	CoP 4	-
Total (MMstb / Bscf / MM GBP)	0.4	37.5	0.7	0.6	188.0		499.0

Table A - 4: Catcher 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	15.0	0.4	-	0.6	82.5	CoP 0	0.8
2027	13.8	0.0	-	0.5	221.4	CoP 1	63.3
2028	10.4	-	-	0.5	207.3	CoP 2	23.3
2029	7.9	-	-	0.5	189.0	CoP 3	66.2
2030	6.4	-	-	0.5	181.1	CoP 4	87.4
2031	2.7	-	-	-	143.7	CoP 5	65.6
2032	-	-	-	-	-	CoP 6+	17.9
Total (MMstb / Bscf / MM GBP)	17.8	0.1	-	2.6	1,025.0		324.5

Table A - 5: Catcher 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	16.1	0.7	-	0.6	82.7	CoP 0	0.8
2027	15.9	0.3	-	0.5	220.8	CoP 1	63.3
2028	14.3	0.0	-	0.5	226.2	CoP 2	23.3
2029	12.5	2.8	-	0.5	213.4	CoP 3	66.2
2030	10.9	4.0	-	0.5	203.1	CoP 4	87.4
2031	5.0	0.6	-	-	139.8	CoP 5	65.6
2032	-	-	-	-	-	CoP 6+	17.9
Total (MMstb / Bscf / MM GBP)	24.4	3.0	-	2.6	1,086.0		324.5

Table A - 6: Catcher 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	17.2	1.1	-	0.6	83.0	CoP 0	0.8
2027	17.6	0.8	-	0.5	221.5	CoP 1	63.3
2028	16.0	0.3	-	0.5	235.7	CoP 2	23.3
2029	14.5	0.5	-	0.5	225.1	CoP 3	66.2
2030	15.8	8.7	-	0.5	231.4	CoP 4	87.4
2031	7.0	4.5	-	-	143.7	CoP 5	65.6
2032	-	-	-	-	-	CoP 6+	17.9
Total (MMstb / Bscf / MM GBP)	29.0	5.6	-	2.6	1,140.3		324.5

Table A - 7: GEAD 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	5.3	-	-	5.5	48.2	CoP 0	-
2027	5.9	-	-	10.2	78.7	CoP 1	194.2
2028	4.6	-	-	9.6	75.9	CoP 2	194.2
2029	3.9	-	-	0.2	73.0	CoP 3	194.2
2030	3.2	-	-	0.2	72.7	CoP 4	-
2031	2.2	-	-	3.8	72.9	CoP 5	-
2032	2.2	-	-	0.2	72.8	CoP 6+	-
2033	2.0	-	-	0.2	72.8		-
2034	1.8	-	-	0.2	72.9		-
2035	1.7	-	-	0.2	97.9		-
2036	1.2	-	-	0.2	72.8		-
2037	1.2	-	-	0.2	72.8		-
2038	1.1	-	-	0.2	72.8		-
2039	1.0	-	-	0.2	72.8		-
2040	1.0	-	-	0.2	72.8		-
2041	0.8	-	-	0.2	72.8		-
2042	0.9	-	-	0.2	72.8		-
2043	0.8	-	-	0.2	72.8		-
2044	0.7	-	-	0.2	72.8		-
Total (MMstb / Bscf / MM GBP)	14.2	-	-	31.9	1,393.0		582.6

Table A - 8: GEAD 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	6.1	-	-	5.5	47.6	CoP 0	-
2027	7.2	-	-	10.2	78.3	CoP 1	194.2
2028	6.1	-	-	9.6	75.8	CoP 2	194.2
2029	5.2	-	-	0.2	72.9	CoP 3	194.2
2030	4.7	-	-	0.2	72.6	CoP 4	-
2031	3.8	-	-	3.8	72.8	CoP 5	-
2032	3.9	-	-	0.2	72.8	CoP 6+	-
2033	3.2	-	-	0.2	72.8		-
2034	2.9	-	-	0.2	72.8		-
2035	2.7	-	-	0.2	97.8		-
2036	2.2	-	-	0.2	72.9		-
2037	2.3	-	-	0.2	72.8		-
2038	2.2	-	-	0.2	72.8		-
2039	2.1	-	-	0.2	72.8		-
2040	2.0	-	-	0.2	72.9		-
2041	1.7	-	-	0.2	72.8		-
2042	1.8	-	-	0.2	72.8		-
2043	1.7	-	-	0.2	72.8		-
2044	1.4	-	-	0.2	72.8		-
Total (MMstb / Bscf / MM GBP)	21.9	-	-	31.9	1,391.8		582.6

Table A - 9: GEAD 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	7.0	-	-	5.5	47.0	CoP 0	-
2027	8.6	-	-	10.2	77.7	CoP 1	194.2
2028	7.6	-	-	9.6	75.6	CoP 2	194.2
2029	6.8	-	-	0.2	72.7	CoP 3	194.2
2030	6.2	-	-	0.2	72.4	CoP 4	-
2031	5.1	-	-	3.8	72.7	CoP 5	-
2032	5.4	-	-	0.2	72.6	CoP 6+	-
2033	5.0	-	-	0.2	72.7		-
2034	4.7	-	-	0.2	72.7		-
2035	4.3	-	-	0.2	97.7		-
2036	3.6	-	-	0.2	72.8		-
2037	3.8	-	-	0.2	72.7		-
2038	3.5	-	-	0.2	72.7		-
2039	3.2	-	-	0.2	72.7		-
2040	3.1	-	-	0.2	72.8		-
2041	2.6	-	-	0.2	72.7		-
2042	2.8	-	-	0.2	72.7		-
2043	2.7	-	-	0.2	72.7		-
2044	2.6	-	-	0.2	72.8		-
Total (MMstb / Bscf / MM GBP)	31.1	-	-	31.9	1,388.5		582.6

Table A - 10: Chiswick 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.2	14.0	-	0.9	15.9	CoP 0	-
2027	0.1	12.0	-	2.7	28.0	CoP 1	-
2028	0.1	10.8	-	3.0	24.1	CoP 2	-
2029	0.0	4.3	-	3.0	10.7	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.1	12.5	-	9.6	78.7		-

Table A - 11: Chiswick 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbbl/d				
2026 H2	0.2	16.2	-	1.4	17.8	CoP 0	-
2027	0.2	16.0	-	2.9	35.0	CoP 1	-
2028	0.2	16.3	-	3.0	32.7	CoP 2	-
2029	0.1	7.8	-	3.0	16.4	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.2	17.6	-	10.3	102.0		-

Table A - 12: Chiswick 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbbl/d				
2026 H2	0.2	17.9	-	1.5	19.4	CoP 0	-
2027	0.2	18.2	-	2.9	38.7	CoP 1	-
2028	0.2	19.2	-	3.0	37.4	CoP 2	-
2029	0.1	9.4	-	3.0	19.2	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.2	20.4	-	10.5	114.7		-

Table A - 13: Grove 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbbl/d				
2026 H2	0.04	6.2	-	0.2	9.5	CoP 0	-
2027	0.03	5.5	-	0.2	16.5	CoP 1	-
2028	0.03	4.9	-	-	14.2	CoP 2	-
2029	0.01	2.1	-	-	6.7	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.03	5.7	-	0.4	46.9		-

Table A - 14: Grove 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.05	7.8	-	0.3	10.9	CoP 0	-
2027	0.05	7.5	-	0.3	19.9	CoP 1	-
2028	0.04	7.2	-	-	17.9	CoP 2	-
2029	0.02	3.3	-	-	8.8	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.05	8.0	-	0.6	57.6		-

Table A - 15: Grove 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.06	9.3	-	0.3	12.2	CoP-5	-
2027	0.06	9.3	-	0.4	23.1	CoP-4	-
2028	0.06	9.6	-	-	21.6	CoP-3	-
2029	0.03	4.6	-	-	10.9	CoP-2	-
Total (MMstb / Bscf / MM GBP)	0.06	10.3	-	0.7	67.9		-

Table A - 16: Kew 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.02	2.0	-	0.1	2.1	CoP 0	-
2027	0.00	0.4	-	0.0	0.9	CoP 1	-
2028	-	-	-	-	-	CoP 2	-
2029	-	-	-	-	-	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.01	0.5	-	0.1	3.1		-

Table A - 17: Kew 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.02	2.3	-	0.1	2.4	CoP 0	-
2027	0.02	1.6	-	0.1	3.6	CoP 1	-
2028	0.01	0.6	-	-	1.4	CoP 2	-
2029	-	-	-	-	-	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.01	1.2	-	0.1	7.5		-

Table A - 18: Kew 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.03	2.5	-	0.1	2.6	CoP-5	-
2027	0.02	1.8	-	0.1	4.0	CoP-4	-
2028	0.01	1.0	-	-	2.5	CoP-3	-
2029	-	-	-	-	-	CoP-2	-
Total (MMstb / Bscf / MM GBP)	0.02	1.5	-	0.2	9.1		-

Table A - 19: J3C 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.002	1.2	-	0.1	1.4	CoP 0	-
2027	0.000	0.0	-	0.0	0.1	CoP 1	-
2028	-	-	-	-	-	CoP 2	-
2029	-	-	-	-	-	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.000	0.2	-	0.1	1.5		-

Table A - 20: J3C 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.002	1.7	-	0.1	1.7	CoP 0	-
2027	0.002	1.7	-	0.1	3.5	CoP 1	-
2028	0.002	1.7	-	-	3.4	CoP 2	-
2029	0.001	0.8	-	-	1.7	CoP 3	-
Total (MMstb / Bscf / MM GBP)	0.003	1.9	-	0.1	10.3		-

Table A - 21: J3C 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.005	3.4	-	0.1	3.4	CoP-5	-
2027	0.005	3.3	-	0.1	6.7	CoP-4	-
2028	0.005	3.4	-	-	6.3	CoP-3	-
2029	0.002	1.7	-	-	3.2	CoP-2	-
Total (MMstb / Bscf / MM GBP)	0.005	3.7	-	0.3	19.6		-

Table A - 22: Cygnus 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.4	119.3	-	13.1	51.7	CoP 0	-
2027	0.3	95.1	-	41.6	90.9	CoP 1	81.2
2028	0.3	81.4	-	7.2	84.5	CoP 2	81.2
2029	0.2	56.2	-	7.2	80.2	CoP 3	81.2
2030	0.1	38.9	-	7.2	75.5	CoP 4	-
2031	0.1	26.9	-	7.2	77.7	CoP 5	-
2032	0.1	18.6	-	7.2	82.0	CoP 6+	-
2033	0.0	12.8	-	7.2	80.0		-
2034	0.0	6.9	-	7.2	59.8		-
Total (MMstb / Bscf / MM GBP)	0.5	145.0	-	105.1	682.4		243.6

Table A - 23: Cygnus 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.4	134.4	-	13.1	53.6	CoP 0	-
2027	0.3	108.6	-	41.6	93.4	CoP 1	81.2
2028	0.3	90.4	-	7.2	86.2	CoP 2	81.2
2029	0.3	92.0	-	7.2	85.9	CoP 3	81.2
2030	0.2	70.4	-	7.2	82.2	CoP 4	-
2031	0.2	53.8	-	7.2	84.1	CoP 5	-
2032	0.1	41.2	-	7.2	88.5	CoP 6+	-
2033	0.1	31.5	-	7.2	86.7		-
2034	0.1	24.1	-	7.2	87.5		-
2035	0.1	18.4	-	-	90.6		-
2036	0.0	14.1	-	-	90.1		-
2037	0.0	10.8	-	-	89.7		-
2038	0.0	4.4	-	-	44.4		-
Total (MMstb / Bscf / MM GBP)	0.7	229.1	-	105.1	1,063.0		243.6

Table A - 24: Cygnus 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.5	148.1	-	13.1	55.3	CoP 0	-
2027	0.4	125.2	-	41.6	96.8	CoP 1	81.2
2028	0.3	99.8	-	7.2	87.9	CoP 2	81.2
2029	0.3	90.8	-	7.2	87.3	CoP 3	81.2
2030	0.3	102.6	-	7.2	87.7	CoP 4	-
2031	0.3	82.3	-	7.2	89.1	CoP 5	-
2032	0.2	66.0	-	7.2	93.3	CoP 6+	-
2033	0.2	52.9	-	7.2	91.3		-
2034	0.1	42.4	-	7.2	91.4		-
2035	0.1	34.0	-	-	92.6		-
2036	0.1	27.3	-	-	91.7		-
2037	0.1	21.9	-	-	91.1		-
2038	0.1	17.6	-	-	90.5		-
2039	0.0	14.1	-	-	90.1		-
2040	0.0	11.3	-	-	89.7		-
2041	0.0	9.1	-	-	89.5		-
Total (MMstb / Bscf / MM GBP)	1.0	318.5	-	105.1	1,415.4		243.6

Table A - 25: Cygnus 1P gross developed plus undeveloped production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.4	127.3	-	98.0	53.7	CoP 0	-
2027	0.4	120.4	-	71.3	95.6	CoP 1	88.8
2028	0.3	101.7	-	7.2	88.3	CoP 2	88.8
2029	0.2	71.0	-	7.2	83.4	CoP 3	88.8
2030	0.2	49.6	-	7.2	78.0	CoP 4	-
2031	0.1	33.7	-	7.2	79.7	CoP 5	-
2032	0.1	20.6	-	7.2	82.8	CoP 6+	-
2033	0.0	12.8	-	7.2	80.0		-
2034	0.0	6.9	-	7.2	59.8		-
Total (MMstb / Bscf / MM GBP)	0.6	175.7	-	219.7	701.3		266.5

Table A - 26: Cygnus 2P gross developed plus undeveloped production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.5	150.3	-	98.0	56.6	CoP 0	-
2027	0.5	157.6	-	71.3	105.4	CoP 1	88.8
2028	0.4	126.8	-	7.2	92.5	CoP 2	88.8
2029	0.4	116.6	-	7.2	91.9	CoP 3	88.8
2030	0.3	87.2	-	7.2	85.2	CoP 4	-
2031	0.2	64.4	-	7.2	86.1	CoP 5	-
2032	0.2	47.1	-	7.2	89.8	CoP 6+	-
2033	0.1	35.9	-	7.2	87.8		-
2034	0.1	25.8	-	7.2	87.9		-
2035	0.1	18.4	-	-	90.6		-
2036	0.0	14.1	-	-	90.1		-
2037	0.0	10.8	-	-	89.7		-
2038	0.0	4.4	-	-	44.4		-
Total (MMstb / Bscf / MM GBP)	0.9	286.6	-	219.7	1,098.0		266.5

Table A - 27: Cygnus 3P gross developed plus undeveloped production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.5	172.0	-	98.0	59.4	CoP 0	-
2027	0.6	194.9	-	71.3	115.3	CoP 1	88.8
2028	0.5	156.9	-	7.2	99.7	CoP 2	88.8
2029	0.4	129.1	-	7.2	94.1	CoP 3	88.8
2030	0.4	130.4	-	7.2	92.0	CoP 4	-
2031	0.3	102.1	-	7.2	92.1	CoP 5	-
2032	0.3	78.6	-	7.2	95.4	CoP 6+	-
2033	0.2	61.6	-	7.2	92.9		-
2034	0.2	49.2	-	7.2	92.6		-
2035	0.1	39.2	-	-	93.2		-
2036	0.1	31.3	-	-	92.2		-
2037	0.1	22.4	-	-	91.1		-
2038	0.1	17.7	-	-	90.5		-
2039	0.0	14.2	-	-	90.1		-
2040	0.0	11.4	-	-	89.7		-
2041	0.0	9.1	-	-	89.5		-
2042	0.0	0.2	-	-	22.1		-
Total (MMstb / Bscf / MM GBP)	1.3	414.5	-	219.7	1,492.0		266.5

Table A - 28: Clipper South 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	16.0	-	-	11.6	CoP 0	-
2027	0.009	13.7	-	-	20.0	CoP 1	10.6
2028	0.010	10.4	-	-	19.3	CoP 2	10.6
2029	0.006	6.4	-	-	17.7	CoP 3	10.6
2030	0.005	5.4	-	-	17.8	CoP 4	-
2031	0.005	4.9	-	-	18.0	CoP 5	-
2032	0.004	4.2	-	-	18.6	CoP 6+	-
2033	0.004	4.0	-	-	18.6		-
2034	0.004	3.6	-	-	18.6		-
2035	0.003	3.2	-	-	18.6		-
2036	0.003	2.9	-	-	18.6		-
Total (MMstb / Bscf / MM GBP)	0.02	24.4	-	-	197.3		31.8

Table A - 29: Clipper South 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	18.2	-	-	11.6	CoP 0	-
2027	0.012	16.2	-	-	21.0	CoP 1	10.6
2028	0.013	13.2	-	-	20.7	CoP 2	10.6
2029	0.012	12.3	-	-	21.1	CoP 3	10.6
2030	0.009	8.8	-	-	20.2	CoP 4	-
2031	0.006	6.2	-	-	19.1	CoP 5	-
2032	0.005	5.6	-	-	20.0	CoP 6+	-
2033	0.005	5.4	-	-	20.9		-
2034	0.005	5.1	-	-	21.4		-
2035	0.005	4.7	-	-	25.3		-
2036	0.004	4.3	-	-	26.0		-
Total (MMstb / Bscf / MM GBP)	0.03	33.3	-	-	227.5		31.8

Table A - 30: Clipper South 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	19.5	-	-	11.6	CoP 0	-
2027	0.014	17.9	-	-	21.7	CoP 1	10.6
2028	0.015	15.9	-	-	22.0	CoP 2	10.6
2029	0.015	15.3	-	-	22.7	CoP 3	10.6
2030	0.013	13.4	-	-	23.1	CoP 4	-
2031	0.012	12.4	-	-	23.7	CoP 5	-
2032	0.009	9.1	-	-	23.5	CoP 6+	-
2033	0.006	6.4	-	-	22.1		-
2034	0.006	6.1	-	-	22.8		-
2035	0.006	5.8	-	-	27.4		-
2036	0.005	5.3	-	-	28.4		-
Total (MMstb / Bscf / MM GBP)	0.04	42.9	-	-	249.0		31.8

Table A - 31: Galleon 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.04	17.6	-	-	10.6	CoP 0	-
2027	0.03	14.7	-	-	23.1	CoP 1	0.8
2028	0.02	10.3	-	-	21.5	CoP 2	2.6
2029	0.02	8.2	-	-	20.7	CoP 3	5.9
2030	0.02	8.4	-	-	20.8	CoP 4	77.9
2031	0.02	7.6	-	-	20.5	CoP 5	4.5
2032	0.02	7.1	-	-	20.3	CoP 6+	-
2033	0.01	6.0	-	-	19.9		-
2034	0.01	5.9	-	-	19.9		-
2035	0.01	5.4	-	-	19.8		-
2036	0.01	4.4	-	-	19.4		-
Total (MMstb / Bscf / MM GBP)	0.1	31.7	-	-	216.5		91.7

Table A - 32: Galleon 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.04	20.4	-	-	11.2	CoP 0	-
2027	0.04	19.1	-	-	24.8	CoP 1	0.8
2028	0.04	17.2	-	-	24.1	CoP 2	2.6
2029	0.03	13.4	-	-	22.6	CoP 3	5.9
2030	0.03	12.9	-	-	22.5	CoP 4	77.9
2031	0.02	10.6	-	-	21.6	CoP 5	4.5
2032	0.02	9.7	-	-	21.3	CoP 6+	-
2033	0.02	8.5	-	-	20.9		-
2034	0.02	8.9	-	-	21.1		-
2035	0.02	8.5	-	-	20.9		-
2036	0.02	8.1	-	-	20.8		-
Total (MMstb / Bscf / MM GBP)	0.1	46.4	-	-	231.7		91.7

Table A - 33: Galleon 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	0.05	23.2	-	-	11.7	CoP 0	-
2027	0.05	22.1	-	-	25.9	CoP 1	0.8
2028	0.04	20.9	-	-	25.5	CoP 2	2.6
2029	0.04	18.1	-	-	24.4	CoP 3	5.9
2030	0.04	18.1	-	-	24.4	CoP 4	77.9
2031	0.03	15.9	-	-	23.6	CoP 5	4.5
2032	0.03	15.1	-	-	23.4	CoP 6+	-
2033	0.03	13.0	-	-	22.6		-
2034	0.02	11.6	-	-	22.1		-
2035	0.02	11.2	-	-	22.0		-
2036	0.02	10.6	-	-	21.7		-
Total (MMstb / Bscf / MM GBP)	0.1	61.4	-	-	247.2		91.7

Table A - 34: Eris 1P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	1.4	0.004	-	3.2	CoP 0	-
2027	-	1.3	0.003	-	5.3	CoP 1	-
2028	-	1.2	0.003	-	4.1	CoP 2	-
2029	-	1.1	0.003	-	4.1	CoP 3	-
Total (MMstb / Bscf / MM GBP)	-	1.6	0.004	-	16.7		-

Table A - 35: Eris 2P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	2.2	0.006	-	4.4	CoP 0	-
2027	-	2.1	0.005	-	7.0	CoP 1	-
2028	-	1.9	0.005	-	5.3	CoP 2	-
2029	-	1.8	0.005	-	5.2	CoP 3	-
Total (MMstb / Bscf / MM GBP)	-	2.5	0.007	-	21.9		-

Table A - 36: Eris 3P gross developed production and cost forecasts

Date	Annual Sales Rate			CAPEX (Real) MM GBP	OPEX (Real) MM GBP	Dynamic ABEX Year	ABEX (Real) MM GBP
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d				
2026 H2	-	2.9	0.008	-	5.5	CoP 0	-
2027	-	2.8	0.007	-	8.8	CoP 1	-
2028	-	2.7	0.007	-	6.5	CoP 2	-
2029	-	2.5	0.007	-	6.5	CoP 3	-
Total (MMstb / Bscf / MM GBP)	-	3.5	0.009	-	27.3		-

Appendix 2: Reserves and Resource Definitions

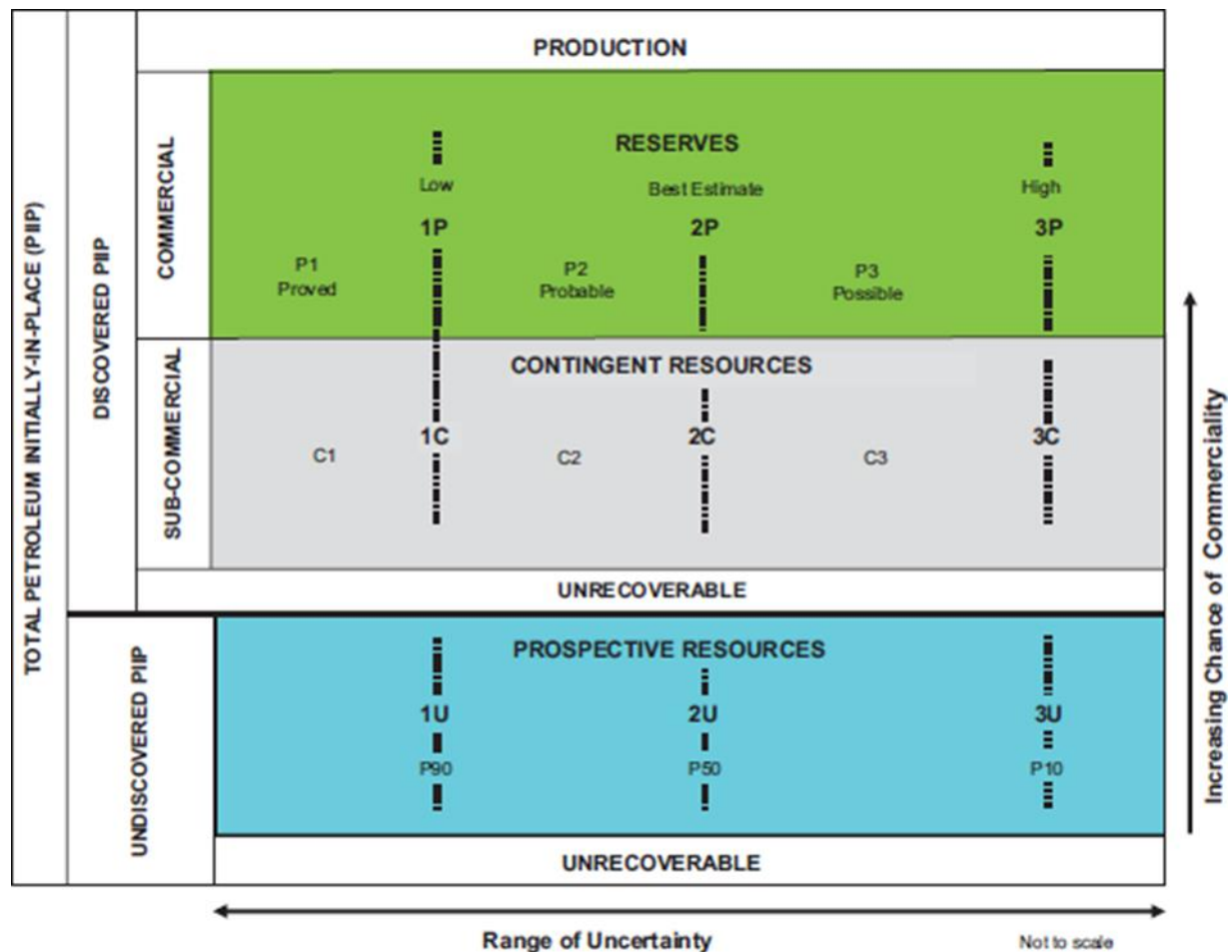
The table below identifies the categories that form the basis of our classification of reserves, resources and values presented in this report. The definitions used in this report are those set out in the Petroleum Resources Management System (SPE-PRMS) as sponsored by Society of Petroleum Engineers (“SPE”), World Petroleum Council (“WPC”), American Association of Petroleum Geologists (“AAPG”), Society of Petroleum Evaluation Engineers (“SPEE”), Society of Exploration Geophysicists (“SEG”), Society of Petrophysicists and Well Log Analysts (“SPWLA”), and the European Association of Geoscientists & Engineers (“EAGE”).

For full definitions and guidance on their application, the reader should refer to either SPE-PRMS (<https://www.spe.org/en/industry/reserves/>).

Although not all the definition groupings may be applicable to this report, they have been included here to ensure appropriate context of the definitions that apply to this report.

1. **Resources** encompass all petroleum quantities that originally existed on or within the earth’s crust in naturally occurring accumulations, including discovered and undiscovered plus quantities already produced. Total Resource is equivalent to Petroleum Initially-in-Place (PIIP).

The following figure illustrates the relationship of the different resources within the SPE-PRMS Resources classification framework and aids in placing the subsequent definitions in context.



2. **Total Petroleum Initially-in-Place** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations and is potentially producible. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.
3. **Undiscovered Petroleum Initially-in-Place** is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The potentially recoverable portion of Undiscovered PIIP is referred to as Prospective Resources; the remainder is unrecoverable.
4. **Discovered Petroleum Initially-in-Place** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered PIIP includes production, Reserves and Contingent Resources; the remainder is unrecoverable.
5. **Discovery** is the confirmation of the existence of an accumulation of a significant quantity of potentially recoverable petroleum.

6. A **Known Accumulation** is one that has been penetrated by a well that has demonstrated the existence of a significant quantity of potentially recoverable petroleum.
7. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.
8. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development projects not currently considered to be commercial due to one or more contingencies. Contingent Resources have an associated chance of development.
9. **Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:
 - analysis of drilling, geological, geophysical and engineering data;
 - the use of established technology;
 - specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
 - a maximum remaining reserve life of 50 years.

Reserves are classified according to the degree of certainty associated with the estimates.

10. **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
11. **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
12. **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 3.1 of SPE-PRMS.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

13. **Developed Reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
14. **Developed Producing Reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
15. **Developed Non-Producing Reserves** are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
16. **Undeveloped Reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling and completing a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned and are expected to be developed within a limited time.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions 10, 11 and 12 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

- There is a 90% probability that at least the estimated proved reserves will be recovered.
- There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Levels of Certainty for Resources

The same levels of certainty as described above for reserves, represented by a probability distribution of the low, best and high volume estimates, can be applied to Contingent and Prospective Resources as reflected with the 1C, 2C, 3C, C1, C2 and C3; or 1U, 2U and 3U resources categories and shown on the resources classification figure on the horizontal axis.

Additional clarification of certainty levels associated with resources estimates and the effect of aggregation is provided in Sections 2.2 and 4.2 of SPE. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

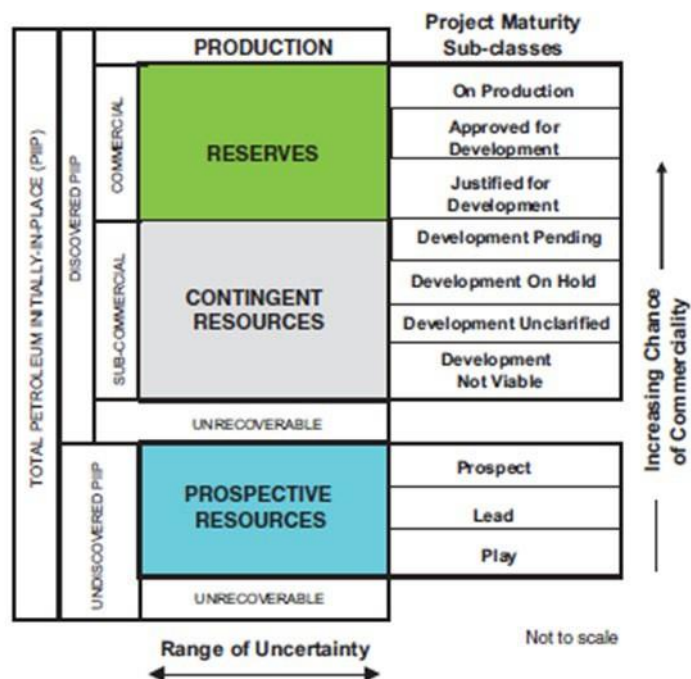
17. **Chance of Commerciality** is the product of the chance of geologic discovery and the chance of development and is used to estimate risk resources by multiplying with the resource volumes. The chance of geologic discovery for Contingent Resources is 100 percent, thus the Chance of Commerciality of Contingent Resources is equal to the chance of development. The Chance of Commerciality is used to estimate the level of maturity of the resource classification as reflected by its' use as an axis on the right side of the Resources Classification Framework as shown in the following figure.
18. **Chance of Development** is the estimated probability that a known accumulation, once discovered, will be commercially developed. The Chance of Development is the product of the contingencies applicable to a particular project. The applicable contingencies may include one or more of the following:
 - **Evaluation Drilling** – the geological continuity of the reservoir needs to be confirmed to reduce the distance from proven productivity;
 - **Regulatory Approval** – Approval from the applicable regulatory agency or agencies has not been received;
 - **Economic Factors** – The future product pricing and capital costs may not be at a level or sufficiently defined - and may also include other underlying factors including market conditions, exchange rates, fiscal terms and taxes - to establish the economic viability of the project;
 - **Corporate Commitment** – The final investment decision and endorsement from the Company and / or the project co-venturers has not been made, nor is there a reasonable expectation these can be arranged in a reasonable time frame, such that the project can move

forward. A technically mature and feasible field development plan may also need to be developed;

- **Timing of Production or Development** – The current development plan may not commence within a reasonable time period;
- **Market Access** – Infrastructure or access to existing facilities may not be in place or sales contracts have not been executed that will allow the production products to access viable markets;
- **Technology Under Development** – The technology required to commercially develop the area is not currently available nor is it under active development;
- **Legal Factors** – Factors that have been brought forward regarding the ability to explore, produce and sell the hydrocarbons;
- **Political Factors** – Political unrest may impede the development in the area;
- **Social License** – One or more of the jurisdictions in which the project area is located has policies in place that restrict certain types of development due to environmental concerns.

19. **Chance of Geologic Discovery** (or just Chance of Discovery) is the estimated probability that exploration activities will confirm the existence of a significant accumulation or potentially recoverable petroleum. The Chance of Geologic Discovery is the product of one or more applicable geologic factors which include:

- **Source** – The presence of source rock in reasonable proximity to the target that has generated, or is generating, hydrocarbon from organic material trapped in the rock;
- **Migration** – There is a path that allowed for the migration of the hydrocarbon from the source to the reservoir;
- **Reservoir** – The presence of rock with sufficient thickness, porosity, and permeability to be commercially productive;
- **Trap (or Seal)** – The reservoir rock is bounded by impermeable layers prior to the time of migration that has allowed the migrating hydrocarbon to accumulate within the reservoir rock;
- **Structure** – the geometry of the anticipated accumulation is able to contain the migrating hydrocarbons in the form of a stratigraphic and / or structural trap. This factor may not apply to unconventional resources, or accumulations that are pervasive throughout a large area and not significantly affected by hydrodynamic influences such as coal-bed methane, gas hydrates, natural bitumen, tight oil, tight gas or oil shale.



The **Project Maturity Sub-class** represents the maturity of the project and sets out the associated actions required to move the project towards commercial production. The boundaries between the different levels of project maturity are normally project decision gates and can vary from organization to organization dependent upon the established internal approval process for project expenditures.

20. A **Play** is the lowest and least defined level of Prospective Resources and is a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects.
21. A **Lead** is the next level of Prospective Resources and is a project that is poorly defined and requires additional data acquisition and/or evaluation.
22. A **Prospect** is the best defined level of Prospective Resources and represents a project that is sufficiently well defined to represent a viable drilling target, although remains undiscovered.
23. **Development Not Viable** is the lowest level of Contingent Resources and represents a discovered accumulation for which there are contingencies resulting in there being no current plans to develop or acquire additional data at the time due to limited commercial potential.
24. **Development Not Clarified** is the second lowest level of Contingent Resources and is a discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. A plan for future evaluation should exist but further study or appraisal work will be ongoing in order to establish the actions necessary to move the project forward to commercial maturity.

25. **Development On Hold** is the second highest level of Contingent Resources and represents a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
26. **Development Pending** is the highest level of Contingent Resources and represents a discovered accumulation where development activities are ongoing to justify commercial development in the foreseeable future.
27. **Justified for Development** is the lowest level of Reserves and represents a development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectations that all necessary approvals/contracts will be obtained.
28. **Approved for Development** is the second level of Reserves and represents a development project that is commercial under the current and/or forecast conditions, has received all approvals and/or contracts necessary for development including the commitment of capital funds and implementation of the development of the project is underway.
29. **On Production** is the highest level of Reserves and reflects the operational execution phase of one or more development projects with the Reserves currently producing or capable of production, including Developed Producing and Developed Non-Producing Reserves.
30. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.
31. **Company Gross Reserves** are the Company's working interest share of the remaining reserves, before deduction of any royalties.
32. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others plus all royalty interest volumes received.
33. **Net Production Revenue** is income derived from the sale of net reserves of oil, non-associated and associated gas, and gas by-products, less all capital and operating costs.
34. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.
35. **Barrels of Oil Equivalent (BOE) Reserves** is the sum of the oil reserves, plus the gas reserves divided by a conversion factor, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using the same conversion factor. Normally the conversion factor

represents an approximation of the nominal heating content or calorific value equivalent to a barrel of oil.

36. **Oil (or Crude Oil)** is a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas. Crude oil volumes are further divided into Product Types, for reporting purposes.
37. **Gas (or Natural Gas)** is a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds. Natural Gas volumes are further divided into Product Types, for reporting purposes.
38. **Non-Associated Gas** is an accumulation of natural gas in a reservoir where there is no crude oil.
39. **Associated Gas** – the gas cap overlying a crude oil accumulation in a reservoir.
40. **Solution Gas** – gas dissolved in crude oil.
41. **Natural Gas By Products** – those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and quantities of non-hydrocarbons such as sulphur and helium.

Product Types sub-classify the principle product types of petroleum, crude oil, gas and by-products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the production types they require to be used for reporting purposes in their jurisdiction.

Other Terms Used in Resource Assessments

- A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
- B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Appendix 3: Nomenclature

Abbreviations			
ABEX	abandonment expenditure	LAS	log ASCII standard
AFE	authorisation for expenditure	LOGGS	Lincolnshire Offshore Gas Gathering System
BBC	bareboat charter agreement	LLP	low-low pressure
BOE	barrels of oil equivalent	LP	low pressure
BRM	Barren Red Measures	LPG	liquefied petroleum gas
CAPEX	capital expenditure	LTRO	locate the remaining oil
CGR	condensate gas ratio	MP	medium pressure
CNOOC	Chinese National Offshore Oil Corporation	MRU	mercury removal unit
CoP	cessation of production	NBP	National Balancing Point
CT	corporate tax	NGL	natural gas liquids
DCA	decline curve analysis	NPV	net present value
DSA	decommissioning security agreement	NSTA	North Sea Transition Authority
DST	drill stem test	NTG	net to gross ratio
ELT	economic limit test	NUI	normally unmanned installation
EPL	energy profits levy	OCM	operating committee meeting
ERSS	Edradour Royal Sovereign Spinnaker	OOR	organic oil recovery
ETS	emissions trading system	OPEX	operating expenditure
EUR	estimated ultimate recovery	OWC	oil-water contact
FDP	field development plan	SAGE	Scottish Area Gas Evacuation
FEED	front end engineering design	SGP	Shetland Gas Plant
FGL	Fulmar Gas Line	SIRGE	Shetland Island Regional Gas Export
FID	final investment decision	SSCM	subsurface committee meeting
FPSO	floating production storage and offloading vessel	STOIIIP	stock tank oil initially in place
FUKA	Frigg UK Association	SVT	Sullom Voe Terminal
G&A	general and administrative	TAR	turnaround
GEAD	Golden Eagle Area Development	TCM	technical committee meeting
GHG	greenhouse gas	TRR	technically recoverable resources
GIIP	Gas initially in place	UKA	UK (carbon) allowance
GLA	Greater Laggan Area	UKCS	UK continental shelf
GMA	Greater Markham Area	WGR	water gas ratio
GOC	gas oil contact	WHP	wellhead platform
GOR	gas oil ratio	WOR	water-oil ratio
GWC	gas water contact	WP&B	work programme and budget
HBP	host baseline profile	WRFM	well and reservoir facility management
HIIPS	high integrity pressure protection system		