

THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt as to what action you should take, you are recommended to immediately seek your own financial advice from your stockbroker, bank manager, solicitor, accountant, fund manager or other appropriate independent financial adviser who is authorised under the Financial Services and Markets Act 2000, as amended (“FSMA”) if you are in the United Kingdom, or from another appropriately authorised independent financial adviser if you are in a territory outside the United Kingdom.

This document comprises a simplified prospectus relating to Serica Energy plc (the “Company” or “Serica”) prepared in accordance with the Prospectus Rules: Admission to Trading on a Regulated Market sourcebook (the “PRM”) of the Financial Conduct Authority (the “FCA”) made under the Public Offers and Admissions to Trading Regulations 2024 (the “POATRs”). This document has been approved by the FCA. The FCA only approves this document as meeting the standards of completeness, comprehensibility and consistency imposed by the rules in the PRM. Such approval should not be considered as an endorsement of the Company that is, or the quality of the securities that are, the subject of this document. This document has been drawn up as a simplified prospectus in accordance with PRM 7. Investors should make their own assessment as to the suitability of investing in the securities. This document has been filed with the FCA and made available to the public in accordance with PRM 9.5.

This document does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue any securities by any person. This document is issued solely in connection with the admission of the ordinary shares of \$0.10 each in the capital of the Company (the “Ordinary Shares”) to the equity shares (commercial companies) category of the Official List of the FCA (the “Official List”) and to trading on London Stock Exchange plc’s main market for listed securities (the “Main Market”) (together, “Admission”). No offer of Ordinary Shares or any other securities is being made in any jurisdiction in connection with Admission.

The Company and the Directors, whose names appear on page 33 of this document, accept responsibility for the information contained in this document. To the best of the knowledge of the Company and the Directors, the information contained in this document is in accordance with the facts and this document makes no omission likely to affect its import.

This document, including any information incorporated herein by reference, should be read in its entirety. In particular, your attention is drawn to the section of this document headed “Risk Factors” for a discussion of certain risks and other factors that should be considered in connection with any investment in the Ordinary Shares. You should not rely solely on the information summarised in the section of this document headed “Summary”.



SERICA ENERGY PLC

(Incorporated in England and Wales under the Companies Act 1985 with registered no. 05450950)

Admission of 393,568,407 Ordinary Shares of \$0.10 each to the equity shares (commercial companies) category of the Official List and to trading on the Main Market of the London Stock Exchange

Sponsor

Peel Hunt LLP

The Ordinary Shares are (as at the date of this document) admitted to trading on AIM, a market operated by the London Stock Exchange. Applications have been made to the FCA and the London Stock Exchange for the admission of all of the Ordinary Shares to the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange’s Main Market, respectively. It is expected that Admission will become effective and that dealings in the Ordinary Shares on the London Stock Exchange will commence at 8.00 a.m. on 27 October 2026. No application has been, or is currently intended to be, made for the Ordinary Shares to be admitted to listing or trading on any other exchange.

Peel Hunt LLP (“Peel Hunt”) is authorised and regulated in the United Kingdom by the FCA. Peel Hunt is acting exclusively for the Company as Sponsor and no one else in connection with the Admission and the

matters set out in this document and will not regard any other person as its client in relation to the Admission and the other matters set out in this document and will not be responsible to anyone other than the Company for providing the protections afforded to clients of Peel Hunt, nor for providing advice in relation to the Admission or any other matter set out herein.

Apart from the responsibilities and liabilities, if any, which may be imposed on Peel Hunt by FSMA or the regulatory regime established thereunder, or under the regulatory regime of any jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, neither Peel Hunt nor any of its subsidiaries, holding companies, branches or affiliates nor any of their respective directors, officers, employees, agents or advisers, owes or accepts or shall assume any duty, responsibility or liability whatsoever (whether direct or indirect and whether arising in contract, in tort, under statute or otherwise) to any person in relation to the Admission or any other matter set out in this document or for any acts or omissions of the Company, and no representation or warranty, express or implied, is made by any of them as to the contents of this document, including its accuracy, completeness, verification or sufficiency, or for any other statement made or purported to be made by the Company, or on its behalf, or by Peel Hunt, or on its behalf, in connection with the Company, the Group, the Admission or the Ordinary Shares, and nothing in this document is, or shall be relied upon as, a promise or representation in this respect, whether or not to the past or future. To the fullest extent permitted by law, Peel Hunt and its subsidiaries, holding companies, branches and affiliates and their respective directors, members, officers, employees, agents, or advisers accordingly disclaim all and any duty, responsibility or liability whatsoever (whether direct or indirect and whether arising in tort, contract, under statute or otherwise (save as referred to above)) which they might otherwise have in respect of this document or any such statement or otherwise. Peel Hunt and its affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services to the Company and its affiliates, for which they received customary fees. Peel Hunt and its affiliates may provide such services to the Company and its affiliates in the future.

NOTICE TO INVESTORS IN THE UNITED STATES OF AMERICA

This document does not constitute an offer to subscribe for or otherwise acquire Ordinary Shares in the United States or any other jurisdiction. The Ordinary Shares have not been and will not be registered under the US Securities Act of 1933, as amended (the “**US Securities Act**”), or under the securities laws of any state or other jurisdiction of the United States and may not be offered, sold, pledged, resold, transferred or delivered, directly or indirectly, within the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act and in compliance with any applicable securities laws of any state or other jurisdiction of the United States.

NOTICE TO ALL INVESTORS

The release, publication and distribution of this document into jurisdictions other than the United Kingdom may be restricted by law. Neither this document nor any advertisement may be distributed or published in any other jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this document comes are required by the Company and Peel Hunt to inform themselves about and observe any such restrictions and to obtain any governmental, exchange control or other consents which may be required, to comply with other formalities which are required to be observed and to pay any issue, transfer or other taxes due in such jurisdiction in connection therewith. Any failure to comply with any such restrictions may constitute a violation of the securities laws or regulations of such jurisdictions. No action has been taken by the Company or by Peel Hunt that would permit possession or distribution of this document or any other publicity material in any jurisdiction where action for that purpose is required, other than in the United Kingdom. To the fullest extent permitted by applicable law, the Company and the Directors, Peel Hunt and all other persons involved in the Admission disclaim any responsibility or liability for the failure to satisfy any such laws, regulations or requirements by any person.

Any reproduction or distribution of this Prospectus, in whole or in part, and any disclosure of its contents or use of any information contained in this Prospectus for any purpose other than considering Admission is prohibited.

This document does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue any securities by any person. No action has been taken by the Company or by Peel Hunt that would permit an offer of the Ordinary Shares or rights thereto in any jurisdiction.

The contents of this document are not to be construed as legal, business or tax advice. Recipients of this document should consult their own lawyer, financial adviser or tax adviser for legal, financial or tax advice in relation to any action in respect of the Ordinary Shares. In making any investment decision, each investor must rely on their own examination, analysis and enquiry of the Company, including the merits and risks involved.

Investors should only rely on the information in this document. No person has been authorised to give any information or to make any representations other than those contained in this document in connection with Admission and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors or Peel Hunt. Neither the delivery of this document nor Admission shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this document or that the information in this document is correct at any time subsequent to its date.

This document is dated 21 October 2026.

TABLE OF CONTENTS

	Page
SUMMARY	5
RISK FACTORS	11
IMPORTANT NOTICES	27
DIRECTORS, COMPANY SECRETARY AND ADVISERS	33
EXPECTED TIMETABLE OF PRINCIPAL EVENTS	34
PART 1 BUSINESS OVERVIEW	35
PART 2 DIRECTORS AND CORPORATE GOVERNANCE	48
PART 3 SELECTED FINANCIAL INFORMATION.....	55
PART 4 CAPITALISATION AND INDEBTEDNESS	60
PART 5 HISTORICAL FINANCIAL INFORMATION.....	62
PART 6 TAXATION.....	63
PART 7 ADDITIONAL INFORMATION.....	67
PART 8 DOCUMENTS INCORPORATED BY REFERENCE	83
PART 9 TECHNICAL TERMS	84
PART 10 DEFINITIONS.....	85
APPENDIX COMPETENT PERSON’S REPORT	89

SUMMARY

1. PRELIMINARY DISCLOSURE

1.1 Purpose of this prospectus

This document is being produced solely in connection with the applications made to the FCA for the Ordinary Shares to be admitted to the equity shares (commercial companies) category of the Official List and to the London Stock Exchange for such Ordinary Shares to be admitted to trading on London Stock Exchange plc's main market for listed securities.

1.2 Reasons for the proposed admission to trading

On 28 September 2026, Serica announced its intention to transfer its listing from AIM to the Main Market. Since being admitted to trading on AIM in 2005, the Group has demonstrated a strong commercial and financial track record, delivered shareholder returns and built a broad and supportive shareholder base. The Board believes that Serica is now of a size and scale to justify its transfer from AIM to the Main Market.

The Group has a proven track record of both organic and inorganic growth, and an ambitious management team. The Board views the transfer to the Main Market as the next step in the Group's growth journey, further enhancing Serica's corporate profile, as well as extending the opportunity to own its Ordinary Shares to a wider pool of UK and global investors. Following Admission, it is expected that the Company's Ordinary Shares will be considered for inclusion in the FTSE 250 and FTSE All Share Indices at FTSE's December 2026 review.

1.3 Intended use of proceeds from the purchase/subscription for the transferable securities

Not applicable. The Company will raise no proceeds from Admission. This document does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue any securities by any person.

2. INTRODUCTION

2.1 Name and ISIN of securities

The Ordinary Shares are registered with ISIN GB00B0CY5V57 and, from Admission, will trade under the symbol "SER".

2.2 Identity and contact details of the issuer, including its LEI

The issuer is Serica Energy plc, a public limited company incorporated in England and Wales with registered number 05450950. The Company's registered office is at 4th Floor, 72 Welbeck Street, London, England, W1G 0AY. The telephone number of the Company is +44 (0) 20 7487 7300. Its LEI is 213800EZZOKA815VC426.

2.3 Contact details of the FCA

This document has been approved by the Financial Conduct Authority. The FCA's head office is at 12 Endeavour Square, London, E20 1JN and its telephone number is +44 (0) 20 7066 1000.

2.4 Date of approval of the prospectus

This document was approved on 21 October 2026.

2.5 Warnings

This summary should be read as an introduction to this document. Any decision to invest in the Ordinary Shares should be based on consideration of this document as a whole by the investor. Investors could lose all or part of their invested capital. Civil liability attaches only to those persons who have tabled the summary, but only where the summary is misleading, inaccurate or inconsistent, when read together with the other parts of this document, or where it does not provide, when read together with the other parts of this document, key information in order to aid investors when considering whether to invest in the Ordinary Shares.

3. KEY INFORMATION ON THE ISSUER

3.1 Who is the issuer of the securities?

(a) *Domicile and legal form, LEI, applicable legislation and country of incorporation*

The Company is a public limited company incorporated in England on 12 May 2005 with registered number 05450950. The Company's LEI is 213800EZZOKA815VC426. The principal legislation under which the Company operates is the Companies Act 2006, as amended.

(b) *Principal activities*

Serica is a British independent upstream oil and gas exploration, development and production company with a broad portfolio of assets located principally on the UK Continental Shelf, with a minor presence on the Dutch Continental Shelf. Serica's strategy is based on applying its expertise to mid-to-late life assets, optimising production, and unlocking subsurface opportunities to extend field life and deliver value for shareholders. This is a two-pronged strategy, with value delivered by M&A through the acquisition of both new production assets and further organic opportunities, and enhanced by operational and subsurface expertise.

Serica has a balanced and diversified portfolio delivering from multiple hubs and associated infrastructure on the UK Continental Shelf and the Dutch Continental Shelf. As at the date of this document, Serica holds interests in 30 producing fields mainly focused around four hubs: the Bruce Hub, the Triton Hub, the West of Shetland Hub and the Southern North Sea. Serica also holds interests in a range of development opportunities. During 2025, it announced a number of acquisitions, including the completed acquisition of Prax Upstream (and associated acquisitions of the West of Shetland assets and interests in the Catcher and Golden Eagle Area Development fields) and the recently completed acquisition of a portfolio of Southern North Sea assets from Spirit Energy.

Serica has identified a range of short-cycle investment projects with the potential to support annual average production of over 50,000 boepd into the next decade. The investment programme is expected to deliver significant rates of return on average across the programme.

(c) *Major shareholders*

Insofar as it is known to the Company as at 19 October 2026, being the latest practicable date prior to the publication of this document (the "**Latest Practicable Date**"), the following persons are interested directly or indirectly in 3 per cent. or more of the total voting rights of the Company:

Shareholder	Number of Shares	Percentage of issued share capital (%)
Mercuria Holdings (UK) Limited ⁽¹⁾	96,618,142	24.55
Mr D and Mrs D Hardy	31,845,605	8.09
Interactive Investor	24,120,085	6.13
Hargreaves Lansdown, stockbrokers	21,085,617	5.36
Orbis Investment Management	15,814,813	4.02
Blackrock	12,248,146	3.11

Note:

(1) An indirect wholly-owned subsidiary of Mercuria Energy Group Limited. MDJ Partnership, a Guernsey partnership, holds 100 per cent. of the issued share capital of MDJ Oil Trading Limited, which indirectly owns a majority stake in Mercuria Energy Group Limited.

(d) *Key managing directors*

Christopher Cox is the Company's Chief Executive Officer and Martin Copeland is the Company's Chief Financial Officer.

(e) *Statutory Auditors*

The Company's current statutory auditor is BDO LLP, having its registered office at 55 Baker Street, London, United Kingdom, W1U 7EU. BDO LLP is a member firm of the Institute of Chartered Accountants in England and Wales.

The Company's statutory auditor in respect of the year ended 31 December 2025 was Ernst & Young LLP, having its registered office at 1 More London Place, London, United Kingdom, SE1 2AF. Ernst & Young LLP is a member firm of the Institute of Chartered Accountants in England and Wales.

3.2 What is the key financial information regarding the issuer?

The tables below set out selected key financial information for the Group for the financial year ended 31 December 2025 and the six-month period ended 30 June 2026, accompanied in each case by comparative financial data. The financial information has been extracted without material adjustment from the audited consolidated financial statements of the Group as at and for the year ended 31 December 2025 and the unaudited interim condensed consolidated financial statements of the Group as at and for the six-month period ended 30 June 2026.

Selected information from the consolidated income statement

\$'000 (except earnings per ordinary share)	Six months ended 30 June		Year ended 31 December	
	2026	2025	2025	2024
	(Unaudited)	(Unaudited)	(Audited)	(Audited)
Sales Revenue	677,099	304,896	601,429	727,178
Operating (loss)/profit	(49,781)	118,087	111,974	186,467
(Loss)/profit before taxation	(75,605)	100,775	80,343	160,498
Profit/(loss) for the period	6,134	(43,094)	(51,822)	92,429
Basic earnings/(loss) per ordinary share (\$)	0.02	(0.11)	(0.13)	0.24
Diluted earnings/(loss) per ordinary share (\$)	0.02	(0.11)	(0.13)	0.23

The Group generated EBITDAX of \$210 million in FY 2025, and EBITDAX of \$301 million in HY 2026.¹

Selected information from the consolidated balance sheet

\$'000	As at 30 June		As at 31 December	
	2026	2025	2025	2024
	(Unaudited)	(Unaudited)	(Audited)	(Audited)
Total assets	1,947,700	1,506,754	1,531,765	1,464,753
Total liabilities	1,325,815	784,657	862,191	668,295
Total equity	621,885	722,097	669,574	796,458

The Group held Adjusted net cash of \$26 million as at 30 June 2026, compared to Adjusted net debt of \$200 million as at 31 December 2025.¹ As at 30 September 2026, the Group had an Adjusted net debt position of \$73 million. Cash outgoings during Q3 2026 included the payment of the final dividend in respect of FY 2025, a cash tax payment in July 2026 and the completion payment in respect of the Spirit Energy Portfolio Acquisition.

Selected information from the cash flow statement

In \$ '000	Six months ended 30 June		Year ended 31 December	
	2026	2025	2025	2024
	(Unaudited)	(Unaudited)	(Audited)	(Audited)
Net cash inflow from operating activities	273,772	172,404	242,216	281,563
Net cash outflow from investing activities	(14,828)	(145,649)	(253,033)	(253,911)
Net cash flow used in financing activities	48,767	(12,421)	(122,337)	(213,278)
Cash and cash equivalents at start of period	18,840	148,460	148,460	335,433
Effect of exchange rates on cash and cash equivalents	(2,100)	11,601	3,534	(1,347)
Cash and cash equivalents at end of period	324,451	174,395	18,840	148,460

¹ **Note:** Non-IFRS measures. EBITDAX represents earnings before interest, tax, depreciation and amortisation, impairments, transaction costs, unrealised hedging expenses, FX translation effects, asset revaluation effects, other non-cash gains or expenses and exploration expenditure. Adjusted net cash/debt means the total cash and cash equivalents, including restricted cash, plus the level of interest bearing loans net of the carrying value of unamortised fees. This is an indicator of the Group's indebtedness and contribution to capital structure. See paragraph 4 of the section of this document entitled "Important Notices" for further information.

The Group's post-tax CFFO was \$243 million for FY 2025, and \$280 million for HY 2026.²

There are no qualifications in the independent auditor's report relating to the Group's financial statements for the year ended 31 December 2025.

3.3 What are the key risks that are specific to the issuer?

- The Group's business and cash flow may be significantly and adversely impacted by oil, gas and NGL prices, which are highly volatile.
- The Group's main production hubs are mid-to-late life facilities, which are exposed to challenges and continuous maintenance costs. Any unexpected failures or outages, or prolonged downtime for maintenance and repair, could result in an interruption in production. The Group may also be required to incur substantial expenditure beyond the amounts budgeted to maintain and, if necessary, replace equipment.
- The Group may be unable to identify suitable future resource maturation opportunities and/or strategic acquisitions or investments.
- The Group may fail to realise anticipated benefits from its strategic acquisitions and investments.
- The Group's capital programmes may be subject to delays and/or cost overruns (including as a result of factors outside of the Group's control).
- The Group faces a range of operational risks and hazards common to the production of and drilling for hydrocarbons.
- The Group's production is concentrated almost entirely in the UK, exposing it to risks associated with having almost all of its production in one country.
- The Group operates in a regulated industry and has been, and may continue to be, affected by regulatory changes.
- The Group has been, and may continue to be, materially adversely affected by changes to tax legislation, regulations and policies. The ring-fence rate applicable to the Group's activities for the year ended 31 December 2025 was 78 per cent. The rate of tax applicable to the Group has resulted in the reduction in the Group's after-tax cash flow and retained income. These measures also increase risk to the Group's future investment planning and may adversely impact the carrying value of the Group's oil and gas properties. Any further increase to the Group's applicable tax rate, or any adverse change to the availability of tax reliefs, could have a material adverse impact on the Group.
- Maintaining production from the Rhum field depends on having an OFAC License and secondary sanctions assurance in place to protect suppliers to the Rhum field from US sanctions on Iran.

4. Key information on the securities

4.1 What are the main features of the securities?

(a) *Type, class and ISIN*

The Ordinary Shares are fully paid ordinary shares in the share capital of the Company with a nominal value of \$0.10 each.

On Admission, the ISIN of the Ordinary Shares will be GB00B0CY5V57. The Ordinary Shares will be traded on the Main Market of the London Stock Exchange under the ticker symbol "SER".

(b) *Currency, denomination, par value, number of securities issued and duration*

The currency of the Ordinary Shares is US dollars. As at the Latest Practicable Date, the share capital of the Company comprised 393,568,407 Ordinary Shares of \$0.10 each and 1 'A' Share of £50,000. The 'A' Share is not listed or publicly traded. The Company does not hold any shares in treasury.

(c) *Rights attached to the Ordinary Shares*

The rights attaching to the Ordinary Shares are uniform in all respects and they form a single class for all purposes, including with respect to voting and for all dividends and other distributions thereafter declared, made or paid on the ordinary share capital of the Company. Holders of Ordinary Shares have the right to

² **Note:** Non-IFRS measures. Post-tax CFFO comprises cash inflow from operations adjusted by the cash tax paid or received for the period. See paragraph 4 of the section of this document entitled "Important Notices" for further information.

receive notice of, and to attend and vote at, any meetings of Shareholders. Each Shareholder entitled to attend and being present in person, by proxy or by a duly authorised corporate representative at a meeting shall have one vote on a show of hands and, on a poll, each such Shareholder shall have one vote for every Ordinary Share of which it is the holder.

(d) Rank of securities in the issuer's capital structure in the event of insolvency

On a return of assets on liquidation or capital reorganisation or otherwise, the assets of the Company remaining after the payment of its liabilities will be applied, first, in paying to the holder(s) of the 'A' Share the sum of £50,000, and, second, in paying to the holders of the Ordinary Shares the balance of such assets in proportion to the amounts paid up on, or credited as paid up on, (excluding any premium) the Ordinary Shares held.

(e) Restrictions on the free transferability of the Ordinary Shares

The Ordinary Shares are freely transferable and there are no restrictions on transfer, save that the Board may refuse to register any instrument of transfer of a certificated share unless the instrument of transfer (a) is lodged, duly stamped, at the registered office, or such other place as the Board may decide, for registration, accompanied by the relevant share certificate and such other evidence (if any) as the Board may reasonably require to prove the title of the intending transferor; (b) is in respect of only one class of share; and (c) is in favour of not more than four transferees.

(f) Dividend policy

Serica's capital allocation framework prioritises maintaining balance sheet strength, funding high-return organic growth, pursuing value-accretive M&A, and delivering sustainable shareholder distributions. The Board has adopted a dividend policy designed to deliver attractive and sustainable shareholder returns while preserving flexibility to fund value-accretive organic growth and M&A. For FY 2026 and annual dividends thereafter, Serica will target shareholder distributions of 15 to 30 per cent. of post-tax CFFO. This range is consistent with the level of Serica's historic shareholder distributions and is expected to support a continuation of the current 16 pence per share aggregate annual dividend, with potential for additional shareholder returns depending on financial performance.

4.2 Where will the securities be traded?

Applications have been made to the FCA and the London Stock Exchange, respectively, for all of the Ordinary Shares to be admitted to the equity shares (commercial companies) category of the Official List of the FCA and to trading on London Stock Exchange plc's main market for listed securities. The current admission of the Ordinary Shares to trading on AIM will be cancelled on the date of Admission. No application has been made or is currently intended to be made for the Ordinary Shares to be admitted to listing or trading on any other exchange.

4.3 What are the key risks that are specific to the securities?

- The market price of the Ordinary Shares could be subject to volatility.
- A liquid market for the Ordinary Shares may not be maintained.
- The Company's ability to pay dividends in the future depends, among other things, on the Group's financial performance and capital investment requirements.

5. Key information on the admission to trading

5.1 Under which conditions and timetable can I invest in this security?

This document does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue any securities by any person. No offer of Ordinary Shares or any other securities is being made in any jurisdiction in connection with Admission. The Ordinary Shares will not be generally made available or marketed to the public in any jurisdiction in connection with Admission.

It is expected that Admission will become effective and that dealings in the Ordinary Shares will commence on the London Stock Exchange at 8.00 a.m. (London time) on 27 October 2026.

5.2 Why is this prospectus being produced?

This document is being produced solely in connection with the applications which have been made to the FCA and the London Stock Exchange for the Ordinary Shares to be admitted to the equity shares (commercial companies) category of the Official List of the FCA and to trading on London Stock Exchange plc's main market for listed securities.

5.3 Conflicts of interest

There are no conflicting interests that are material to Admission.

RISK FACTORS

Any investment in the Ordinary Shares is subject to a number of risks and uncertainties. Accordingly, prior to any investment in the Ordinary Shares, prospective investors should carefully consider the risks and uncertainties associated with any such investment, the Group's business and the industry in which it operates, together with all other information contained in this document, including, in particular, the risk factors described below. If any of the risks described below were to materialise, this may, individually or cumulatively, have a material adverse effect on the Group's business, reputation, results of operations, financial condition and/or prospects and, if any such risk should materialise, the price of the Ordinary Shares may decline, and Shareholders could lose all or part of their investment.

The risks and uncertainties summarised in the section of this document headed "Summary" are the risks that the Company believes to be the most essential to an assessment of whether to consider an investment in the Ordinary Shares. However, as the risks and uncertainties which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors in the Ordinary Shares should consider not only the information on the risks and uncertainties summarised in the section of this document headed "Summary" but also, among other things, the risks and uncertainties described below.

The following factors are not an exhaustive list or explanation of all risks which prospective investors may face when making an investment in the Ordinary Shares. The factors listed under a single heading may not provide a comprehensive view of all risks relevant to the subject to which the heading relates. Additional risks and uncertainties relating to the Group that are not currently known to the Group, or that the Company currently deems immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, reputation, results of operations, financial condition and/or prospects and, if any such additional risk should materialise, the price of the Ordinary Shares may decline, and Shareholders could lose all or part of their investment.

In accordance with the PRM, the most material risk factors have been presented first in each category, but the order in which the remaining risk factors are presented is not necessarily an indication of the likelihood of the risks actually materialising, of the potential significance of the risks or of the scope of any potential harm to the business, reputation, results of operations, financial condition and/or prospects of the Group.

Prospective investors should consider carefully whether an investment in the Ordinary Shares is suitable for them in the light of the information in this document and their personal circumstances.

1. RISKS RELATING TO THE GROUP'S BUSINESS, OPERATIONS AND INDUSTRY

1.1 The Group's business and cash flow may be significantly and adversely impacted by oil, gas and NGL prices, which are highly volatile

The Group's business, results of operations, financial condition, cash flow and prospects depend significantly upon prevailing oil, gas and NGL prices, which may be adversely impacted by geopolitical and global, regional and national macroeconomic conditions. All of the Group's oil and gas production is currently sold at prices linked to the spot market and the significant majority of the Group's NGL production is sold at prices linked to the spot market. Oil, gas and NGLs are commodities for which prices are determined based on global and regional demand, supply and other factors, all of which are beyond the Group's control.

Historically, prices for oil, gas and NGLs have fluctuated widely for many reasons, each outside of the Group's control, including geopolitical uncertainty, threats or acts of terrorism, war or threat of war or resolution of war, political, economic and military developments in oil and gas producing regions generally, and domestic and foreign governmental regulations, policies and actions, including the imposition of sanctions, import and export restrictions, output or production quotas (such as the production policy of OPEC+), taxes and tariffs, global and regional economic and social conditions, prices and availability of new technologies affecting energy consumption, increasing competition from alternative energy sources and trading activities by market participants and others (for example, to hedge against commercial risks).

Oil and gas prices are currently subject to heightened levels of uncertainty resulting from a variety of factors, including continued unrest in the Middle East region and the continued effect of Russia's invasion of Ukraine (and associated sanctions and private sector boycotts of Russian oil and oil products). These factors are expected to continue to contribute to price uncertainty and volatility in the near future. There can be no assurances as to the level of oil, gas and NGL prices that will be achievable in the future.

The Group's revenues, operating results, profitability, future rate of growth and the carrying value of the Group's oil and gas assets depend heavily on the prices it receives for oil and gas sales. Oil and gas prices also affect capital investments and the economics of producing from some wells and assets. Lower oil and

gas prices may result in a reduction in the volumes of the Group's reserves which are economically viable to produce. As a result, the Group might elect to cease production from certain wells at lower prices and some producing fields may reach cessation of production and enter into the decommissioning phase earlier than estimated. A protracted reduction in oil or gas prices may result in a reduction in the volumes of the Group's reserves.

No assurance can be given that oil, gas or NGL prices will remain at levels which enable the Group to operate profitably or at levels that make it economically viable to produce from all current wells. A material or sustained decline in commodity prices would reduce the Group's net production volumes and revenue and result in a decrease in the valuation of the Group's appraisal, development and production properties. The occurrence of any of the foregoing could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.2 The Group's main production hubs are mid-to-late life facilities, which are exposed to challenges and continuous maintenance costs

Serica's business model and strategy involve generating shareholder value primarily from mid-to-late life assets. As such, the Group owns assets which utilise equipment that is ageing and may require intensive maintenance to extend its useful life beyond original design life. There are inherent risks involved with the operation of equipment of this nature. In addition, such facilities could also be more prone to fault or material damage than those which have been constructed more recently. There can be no guarantee that such assets will continue to operate without fault and not suffer material damage or that the amounts expended will ensure continued operation of assets and equipment without fault or damage.

Any unexpected failures or outages, or prolonged downtime for maintenance and repair, could result in an interruption in production, as was the case at the Triton FPSO, where production was suspended a number of times in FY 2024 and FY 2025 to enable remediation work and modifications to be carried out. The Group may also be required to incur substantial expenditure beyond the amounts budgeted to maintain and, if necessary, replace equipment. Any loss of revenue from unplanned outages and significant capital expenditure on these facilities for improvement or maintenance are unlikely to be covered by insurance.

These events could, individually or in combination, reduce the Group's revenues and operating cash flow and in turn, could have a material adverse impact on the Group's business, prospects, financial condition and/or results of operations.

1.3 The Group may be unable to identify suitable future resource maturation opportunities and/or strategic acquisitions or investments

The Group's future success depends on its ability to develop or acquire additional economic reserves. Production from oil and gas reservoirs, particularly in the case of mature fields, is generally characterised by declining production rates that vary depending upon reservoir characteristics and other factors. Part of the Group's strategy is to use its own subsurface expertise and to apply reservoir management techniques to maximise the value of mid-to-late life assets. The Group may be unable to realise the value of its resources and reserves by converting them to production. If the Group's recovery methods do not allow for the extraction of oil and gas in the manner or to the extent that it anticipates, the Group's future results of operations and financial condition could be materially and adversely affected. Further, while active well supervision and effective interventions can contribute to sustaining production rates, over time the production from fields will naturally decline until it becomes no longer economical to continue production.

The Group's reserves and levels of future production also depend on, amongst other things, the success of its activities to identify and mature additional reserves that are economically viable. The Group may be required to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, breaches of security, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment or other factors which may result in drilling operations becoming uneconomic. Further, appraisal and development activities may be subject to delays in obtaining governmental approvals or consents, agreeing development plans and related funding with joint venture partners, access to capital, obtaining sufficient access to storage or transportation facilities or other constraints which could materially adversely affect the Group's replacement of reserves and long-term oil and gas production.

The Group may also seek to grow its oil and gas reserves through strategic acquisitions of and targeted investments in oil and gas businesses or assets. The Group has undertaken a number of acquisitions of oil

and gas assets in the past and, as part of its strategy and business model, will seek to continue to grow its oil and gas reserves through strategic acquisitions of and targeted investments in oil and gas businesses or assets. The Group may face significant competition for assets in the oil and gas sector. Competitors may have greater financial, technical and other resources than the Group or greater ability to borrow or leverage funds to acquire oil and gas businesses and assets. Competition for appropriate acquisition opportunities may increase, thus reducing the number of opportunities available to, and adversely affecting the terms on which acquisitions can be made by, the Group, and thereby limiting the growth potential of the Group.

Thus, the Group's future oil and gas reserves and production and, therefore, its cash flow and results of operations, are highly dependent upon its ability to produce from its current licence interests and its ability to identify and economically exploit further subsurface potential within its current licence interests and/or to select and acquire additional assets either through acquisitions or potentially through future licence awards. The Group may not be able to find, develop, or acquire sufficient additional reserves or resources to replace its current reserves as they are produced. If the Group is unable to replace its reserves in a value accretive manner, the amount and value of its reserves will decrease, and its business, results of operations, financial condition, cash flow, as well as the Company's ability to make distributions to Shareholders, could be materially adversely affected.

1.4 The Group may fail to realise anticipated benefits from its strategic acquisitions and investments

The Group aims to grow its oil and gas reserves through strategic acquisitions and targeted investments. Successful acquisitions and investments require an assessment of a number of factors, including estimates of recoverable reserves, expected profile of production or cost and timing of developments, future hydrocarbon prices, operating costs, capital costs and abandonment costs in respect of those assets. Such assessments and due diligence are inexact and may fail to reveal risks and liabilities (including any environmental and decommissioning liabilities) associated with the asset or business, or the full extent of such risks. In view of the inherent uncertainties of acquisitions, the Group may become affected by defects in title or exposed to environmental, structural or operational defects requiring remediation or giving rise to additional costs or liabilities. The Group may also be required to assume liabilities with respect to an acquisition, including known and unknown environmental and decommissioning liabilities, and, depending on the nature of the seller, may have to acquire interests in properties on an "as is" basis without recourse to the seller of such interest.

In addition, the Group is considering expanding into new geographic areas. While the Group expects to maintain its position as a North Sea-focused business, it may assess both domestic and selected international opportunities where the value case is strong and aligned to its operational strengths and core business model. Expanding the Group's operations in new geographic areas involves inherent costs and uncertainties associated with new competitive and regulatory environments, impact of foreign taxes, restrictions on repatriation of earnings, differences in business cultures and languages, lack of familiarity and burdens of complying with foreign laws, legal standards, regulatory requirements, tariffs and other barriers, and other logistical and management challenges.

The Group may be required to invest a disproportionate amount of management's attention and financial and other resources in order to resolve or address any issues arising from the acquisition or investment, including those arising from adapting to or effectively managing operations in geographic markets outside of the United Kingdom, and therefore detract from the resources remaining for the Group's pre-existing operations. The Group may be exposed to additional costs or liabilities, which may impact the profitability of the investment. There can be no guarantee that the Group will realise any or all of the anticipated benefits of an acquisition or investment into which it enters, either in a timely manner or at all, or that the Group will not incur higher than expected costs and liabilities.

1.5 The Group's capital programmes may be subject to delays and/or cost overruns

Capital programmes may be subject to delays or cost overruns (including as a result of factors outside of the Group's control) that could result in them being less profitable than forecast, generating cash later than expected or requiring additional expenditure. The Group anticipates that in order to continue to implement its stated strategy, it will need to make substantial capital investments for its operations, including for infill drilling as well as its future development and/or production enhancement operations. For example, the Group is finalising a contract for a rig to undertake a multi-well drilling programme principally targeting infill wells and tie-backs across the broader Serica portfolio. The programme is expected to begin with a three-well drilling programme at the Bruce field, which has an estimated pre-tax cost of around \$400 million.

The Group's ongoing and future development projects, including the proposed drilling programme at Bruce, often involve advanced engineering work, extensive procurement activities and complex construction work to be carried out under various contract packages at different locations onshore and offshore. Furthermore, the Group (together with its licence partners) must procure the carrying out of drilling operations, installation, testing and commissioning of offshore installations and obtain governmental and regulatory approval to bring them into use, prior to commencement of production. The complexity of the Group's development projects makes them very sensitive to circumstances which may affect the planned progress or sequence of the various activities, and this may result in delays or cost increases. Where it is not possible to cancel or stop a project or to defer or transfer a licence commitment, the Group may become legally obliged to carry out the activity contrary to its desire or to withdraw on penal terms, either of which could have negative economic impact. The Group's ability to sustain planned levels of capital expenditure may be negatively impacted by the need to reduce costs and preserve capital and liquidity due to unforeseen macroeconomic, geopolitical and other events that are beyond its control.

Any of the foregoing risks could materially and adversely affect the Group's business, prospects, financial condition, cash flow and results of operations.

1.6 The Group faces a range of operational risks and hazards common to the production of and drilling for hydrocarbons

The Group's oil and gas production and drilling operations are subject to numerous risks common to the oil and gas industry, including, but not limited to, premature decline of reservoirs, invasion of water into producing formations, geological uncertainties such as unusual or unexpected rock formations and abnormal geological pressures, oceanographic conditions, low permeability of reservoirs, contamination of oil and gas, blowouts, oil and other chemical spills, explosions, fires, natural disasters, threats or acts of terrorism, uncontrollable flows of oil, gas or well fluids, adverse weather conditions, shortages of skilled labour, delays in obtaining or successful challenges to the grant of government approvals or consents, pollution and other environmental risks.

The UKCS, like other oil producing regions, is prone to difficult weather conditions that can, in some cases, prevent the Group from transporting supplies, personnel and fuel to its facilities, each of which can cause production shut-downs or slowdowns. If mechanical problems, storms or other events on the UKCS curtail a substantial portion of the Group's production or cause damage to any of its facilities, it may have unpredictable and materially adverse impacts on the Group's business, results of operations, financial condition, cash flow and prospects. Longer term changes in weather patterns and more frequent extreme weather events could potentially disrupt business activities and the Group's offshore operations are particularly at risk from severe climatic events.

Mechanical problems, accidents, system malfunctions, physical damage or other events at any of the installations or floating facility or infrastructure operated by the Group or third parties on which the Group relies, may cause a widespread, unexpected production shutdown of the Group's operations. For example, production at the Triton FPSO was suspended a number of times in FY 2024 and FY 2025 to allow extensive remediation work and modifications to be carried out. This resulted in production at the Triton Hub being significantly below forecasts. Furthermore the planned annual shutdown in 2026 was extended beyond the originally scheduled period to complete further remediation work at the Triton Hub, with production currently expected to recommence from around the end of November 2026. Any similar operational problems or extension of scheduled downtime relative to plans in the future could interrupt production, resulting in a material adverse effect to the Group's business, financial condition and results of operations and such events may not be insurable claims.

The occurrence of events such as blowouts, oil spills or gas leaks could result in injury to persons and other species and organisms, loss of life, biodiversity loss or habitat destruction and other environmental damage. These events could also cause substantial damage to the Group's property and reputation and put at risk some or all of the Group's interests in licences, which enable it to explore and produce, and could result in it incurring fines or penalties, criminal sanctions potentially being enforced against the Group and its management, as well as other governmental and third party claims. Consequent production delays and consequent constrained field operating conditions and other adverse actions taken by host governments and third parties may result in revenue and cash flow levels being adversely affected.

The occurrence of any of the foregoing events could have a material adverse effect on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.7 The Group's production is concentrated almost entirely in the UK, exposing it to risks associated with having almost all of its production in one country.

As at the date of this document, almost all of the Group's production comes from oil and gas assets from licences located on the UKCS, with a small amount from assets located on the Dutch Continental Shelf. As a result, the Group may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by processing or transportation capacity constraints, availability of equipment, equipment failure, facilities, availability of personnel, critical services market limitations, weather events or interruption of the processing or transportation of oil.

Significant changes to the UK Government's fiscal policy or regulation of oil and gas production could also have a material impact on the Group's business. Laws and regulations in the UK have changed significantly in the past and continue to be subject to ongoing reforms in response to changes to Government policy, including in respect of licensing requirements, taxation and climate change abatement legislation. The uncertainty around the future regulatory and fiscal regime has impacted, and will continue to impact, decisions the Group makes including in key areas such as the sanctioning of new projects and its approach to acquisitions and its wider capital allocation strategy.

Any events or changes adversely impacting production from the UKCS and operations in the UK, to which almost all of the Group's production is exposed, could have a material adverse effect on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.8 The Group is exposed to counterparty risk in respect of its licence partners

Serica holds interests in 30 producing fields as well as interests in other development and earlier-stage assets. The Group is the operator of the majority of its licences, but also holds interests in licences of which it is not the operator. In addition, as is customary, the Group does not hold 100 per cent. of the interests in all of its fields and licences and, in certain fields and licences, it holds only a minority interest.

Where the Group is an operator of a particular asset, it is dependent on its licence partners complying with their obligations under relevant licences or the agreements pursuant to which the Group operates an asset. Typically, as operator, the Group is able to direct or control certain of the activities or operations relating to a particular asset. There is a risk that a licence partner with licence interests in an asset may elect not to participate in certain activities which the Group believes are required. In addition, in certain cases the consent of a licence partner is required to undertake a particular course of action. Where consent is not forthcoming or the licence partner refuses to follow the Group's proposed course of action, it may not be possible for such activities to be undertaken by the Group alone or in conjunction with other licence partners at the desired time or at all or otherwise, to the extent permitted, such activities may then need to be undertaken with the Group bearing a greater proportion of the risks and costs involved in the project.

In addition, the Group may suffer unexpected costs or losses if a licence partner does not meet funding and other obligations under agreements governing the relationship. In such circumstances, the Group may be required under the terms of the relevant operating agreement to contribute all or part of any such funding shortfall, regardless of the percentage interests that it agreed with such licence partner under such arrangements. As a result, its exposure to a particular licence may increase such that the Group bears a greater proportion of the risks and costs involved which may have a material adverse effect on the Group's business, financial condition and/or results of operations. In addition, the Group may also be subject to claims by its licence partners regarding potential non-compliance with its obligations.

On the other hand, where the Group is not the operator of an asset, although the Group may have certain rights under an operating agreement, the Group will have limited powers to determine the operations and costs relating to such asset. To the extent the Group does not have voting rights to direct or exert influence over operations, the timing and performance of such operations or the costs thereof given the relative size of its interest in the particular asset, it will be dependent on its licence partners acting as operators.

It is possible that the interests of the Group, on the one hand, and the operator and/or other licence partners, on the other will not always be aligned which could result in project delays, additional costs or disagreements. The Group may be required to undertake (or cease or delay undertaking) certain actions in relation to a particular asset which it does not believe are in the best interests of the Group. As a result, the Group may suffer unexpected costs and/or be required to contribute to costs which it does not believe are an efficient use of its capital.

The terms of any relevant operating agreement will generally impose standards and requirements in relation to an operator's activities. While the Group has acquired interests in oil and gas assets that are operated by,

what the Directors believe to be, reputable operators, there can be no assurance that any such operator will observe such standards or requirements. Failure by an operator to comply with its obligations under relevant licences may result in delays or increased costs, lead to fines, penalties and restrictions and/or the withdrawal of licences or termination of the agreements under which it operates. The Group may also be subject to claims by an operator regarding potential non-compliance with the Group's obligations under the relevant licences or operating agreement.

Any of the foregoing could result in unexpected costs or production disruption, and could have a material adverse effect on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.9 The Group relies on the availability of hydrocarbon transportation and infrastructure systems that are owned and operated by third parties, which may experience restrictions or interruptions

The Group and its offtakers rely, and any future offtakers will rely, upon the availability of hydrocarbon transportation systems, such as pipelines and oil tankers, including infrastructure systems that are owned and operated by third parties. The Group may be unable to access the infrastructure and systems which it currently uses or plans to use, or source alternatives or otherwise be subject to interruptions or delays in the availability of infrastructure and systems necessary for the delivery of the Group's oil and gas to commercial markets. Any decrease in the volume transported as a result of unplanned system outages or equipment failures could materially and adversely affect the Group's business, financial condition and results of operations. In addition, such infrastructure may be close to the end of its design life and decisions may be taken to decommission such infrastructure or perform life extension work to maintain continued operations. The Group may be unable to secure contractual arrangements to access third party infrastructure which it needs to transport its products to market on commercially acceptable terms or at all. Failure to reach agreement on terms commercially acceptable to the Group may mean that it is not economically viable to continue to develop projects or exploit reserves from current projects. Any of these events could result in disruptions to the Group's operations, thereby impacting its ability to deliver oil and gas to commercial markets and/or increasing costs associated with the production of oil and gas reliant upon such infrastructure/systems. Further, the Group's offtakers could become subject to increased tariffs or switch to cost share imposed by the third party operators or owners of the transportation systems available for the transport of the Group's oil and gas downstream of the delivery point to the offtaker, which could result in increased costs and reduced profitability.

If the Group is unable to access infrastructure systems facilitating the delivery of its oil and gas to commercial markets, its operations will be materially adversely affected. If it is unable to source the most efficient and expedient infrastructure systems for its assets then delivery of oil and gas to the commercial markets may be negatively impacted, as may the Group's costs associated with the production of oil and gas that is reliant upon such infrastructure/systems.

Furthermore, oil and gas development and appraisal activities are dependent upon the availability of drilling rigs and related third party equipment. High demand for equipment such as drilling rigs or the limited availability of suitably specified rigs in the UK market may affect the availability and cost of, and the Group's access to, such equipment and may delay the Group's activities. Additionally, the wage rates of qualified drilling rig crews and day rates to hire generally rise in response to the increased number of active rigs in service and could increase sharply in the event of a shortage. Any production disruption or material cost increase resulting from infrastructure unavailability or equipment constraints could reduce the Group's revenues and operating cash flow, and in turn, could have a material adverse effect on the Group's business, prospects, financial condition and/or results of operations.

1.10 The level of the Group's oil and gas reserves and contingent resources, their quality and production volumes may be lower than estimated or expected

The information about the Group's reserves and contingent resources set forth in this document has been extracted from the Group's annual report and accounts for the year ended 31 December 2025 and its reserves reports and the Sproule ERCE CPR, which have been prepared and reviewed by competent persons on a basis consistent with the SPE PRMS system. The information represents estimates only and such estimates are forward looking statements which are based on judgments regarding future events that may be inaccurate.

In general, estimates of oil and gas reserves are based on a number of factors and assumptions made as at the date on which the reserves estimates were determined, such as geological and engineering estimates (which have inherent uncertainties), historical production from the assets, the assumed effects of regulation

by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results.

Underground accumulations of hydrocarbons cannot be measured in an exact manner and estimates thereof are a subjective process aimed at understanding the statistical probabilities of recovery. Estimates of the quantity of oil and gas reserves, rates of production and the timing of development expenditures depend upon several variables and assumptions, including the quality and quantity of available data, interpretation of the available geological and geophysical data, future hydrocarbon prices, future operating costs, tax on the extraction of oil and gas reserves, development costs and workover and remedial costs and the judgment of the persons preparing the estimate.

All reserve estimates are subjective. Many of the factors in respect of which assumptions are made when estimating reserves are beyond the control of the Group and therefore these estimates may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or contingent resources evaluation depends on the quality of available information and oil and gas engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves or contingent resources data. Moreover, different reserves engineers may make different estimates of reserves based on the same available data. Actual production, revenues and expenditures with respect to reserves and contingent resources will vary from estimates and the variances may be material. The uncertainties in relation to the estimation of reserves set out above also exist to a greater extent with respect to the estimation of contingent resources. The probability that contingent resources will be discovered, or be economically recoverable, is considerably lower than for reserves. Volumes associated with contingent resources should be considered highly speculative.

If the assumptions upon which the estimates of the Group's oil and gas reserves and contingent resources have been based prove to be incorrect or if the actual reserves or contingent resources available to the Group are otherwise less than the current estimates or of lesser quality than expected, the Group may be unable to recover and produce the estimated levels or quality of oil and gas set out in this document and this may materially and adversely affect the business, prospects, financial condition and results of operations of the Group.

1.11 The Group is dependent on the continued contribution of its Board, executive leadership team and technical, financial and operations personnel

The Group's future operating results depend significantly upon the continued contribution of its Board, executive leadership team and technical, financial and operations personnel. Management of the Group's growth will require, among other things, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel and the presence of adequate supervision.

The Group's success is dependent on the ability of its Board and key members of management to operate its growing business and to manage the ongoing changes from potential future acquisitions. From time to time, there may be changes in the Group's executive leadership team resulting from the hiring or departure of executives, which could disrupt the Group's business. The oil and gas industry is highly competitive and the Group faces competition in relation to the employment and retention of qualified, experienced and skilled management and oil and gas professionals. The Group's competitors include entities with greater technical, physical and financial resources.

The loss of the services of one or more of the Group's Directors, members of the executive leadership team or other key employees for any reason could require significant amounts of time, training and resources to find suitable replacements and integrate them within the business, result in meaningful exit payments being required to be made to the departing individual, and cause disruption to production operations at the Group's core assets, reducing the revenues and operating cash flow and could have a material adverse impact on the Group's reputation, business, prospects, financial condition and/or results of operations.

Attracting and retaining additional skilled personnel will be fundamental to the continued growth of the Group's business. The Group requires skilled personnel in the areas of subsurface interpretation, production optimisation, projects and development, operations, engineering, drilling, business development, oil and gas marketing, finance and accounting. Personnel costs, including salaries, are increasing as industry-wide demand for suitably qualified personnel increases. There is a scarcity of qualified personnel in the more technical areas in which the Group's business operates, such as in the subsurface and engineering

disciplines. The Group may not successfully attract new personnel or retain the existing personnel required to continue to expand its business and to execute and implement the Group's business strategy successfully.

1.12 The Group is dependent on third party contractors and sub-contractors

The Group relies on suppliers and contractors to provide materials and services in conducting its operations. The oil and gas industry requires specialised knowledge. Oil and gas professionals and field operations personnel with the appropriate knowledge and expertise can be scarce and availability of such specialists has been, and is expected to continue to be, impacted by the wider backdrop of economic activity on the UKCS (relative to other oil & gas producing regions), increasing regulation in the oil and gas industry, and changes to government policy and actions, and they may not be readily available at the times and places required, which could result in disruption to the Group's business and operations. Any competitive pressures on the oil field suppliers and contractors could result in a material increase in costs for the services required to conduct the Group's business and operations. Moreover, in certain cases, the Group may exercise limited control over the activities and business practices of these providers and any failure on their part to conduct their business in accordance with acceptable business practices or their failure to provide services of adequate quality that meet the contractually agreed standards on a timely basis could, in addition to any disruption to the Group's business and operations, adversely affect its relationship with key counterparties or its reputation, or expose it to the risk of legal proceedings. Any failure by contractors or service providers to perform adequately or on a timely basis could disrupt the Group's operations and reduce its revenues, and could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.13 The Group is exposed to risks arising from interruption to, or failure of, IT infrastructure

The Group's IT systems are vulnerable to damage, breakdown or interruption from events, some of which are beyond the Group's control, such as fire, natural disasters, power loss or telecommunications or data network failures, unauthorised physical or electronic access, infrastructure changes, human or software errors and interruptions to internet system integrity generally.

If the Group or third party operators are unable to access or control the systems and equipment required to operate the pipelines, installations or floating facility or infrastructure used or owned by the Group, this may lead to disruptions or delays to the production or development of such assets and/or disruptions or delays to the transportation and/or delivery of oil, gas and NGLs to the Group's customers, which could impair the Group's ability to operate its business and sell its oil, gas and NGLs to its customers. Interruptions to, or failure of, such systems and equipment may also compromise the Group's critical safety and monitoring systems, which could increase the likelihood of the occurrence of operational risks and hazards. Any of the foregoing could have a negative impact on the Group's reputation and could result in a material adverse effect on the Group's business, prospects, financial condition, cash flow and/or results of operations.

The Group may also face attempted cyber-attacks and data security breaches designed to penetrate its network security or the security of its internal systems, misappropriate proprietary, confidential and/or sensitive information and/or cause interruptions to services. Such future attacks could include hackers obtaining access to its systems, the introduction of malicious computer code or denial of service attacks. In addition to the potential operational disruptions described above, if an actual or perceived breach of the Group's network security occurs, it may expose the Group to loss of information, litigation, regulatory fines or penalties and other potential liability. A deliberate corruption of the financial or operational data of the Group could affect the Group's ability to meet its regular regulatory and financial reporting obligations. Such a security breach could divert the efforts of the Group's technical and management personnel and require the Group to expend additional resources to enhance its protective measures and/or to investigate and/or remediate any security vulnerabilities. If this happens, the Group's reputation could be harmed, its revenues could decline and its business could suffer. This is a constantly evolving and increasing risk and techniques used change frequently and may not be known until an attack is launched against the Group or its critical third party service providers. There can be no guarantee that the Group will be able to anticipate or implement adequate measures to successfully protect against these attacks and the Group's service providers may likewise be unable to do so.

Any significant IT failure or successful cyber-attack could disrupt production and operations and may result in the incurrence of material costs for the recovery of the Group's IT systems, reducing the Group's revenues and cash flow and materially and adversely affecting the Group's reputation, business, prospects, financial condition and results of operations.

1.14 The Group's insurance coverage may not be adequate for covering all losses arising from potential operational hazards and unforeseen interruptions

The Group insures its operations in accordance with industry practice and regulatory and legislative requirements. However, the Group may elect to not have insurance for certain risks, due to the high premium costs associated with insuring those risks or for various other reasons, including an assessment in some cases that the risks are sufficiently remote or are not capable of being insured.

The Group's operations focused insurance currently includes cover for damage to physical assets, operator's extra expense (well control, seepage and pollution clean-up and re-drill costs), loss of production income and third party liabilities for the Group's exploration and production activities and surety bonds in relation to certain of its obligations to post security under decommissioning security agreements, in each case subject to excesses, exclusions and limitations. The Group's insurance may not be adequate to and/or may not cover all losses or liabilities it may suffer. No assurance can be given that the Group will be able to obtain insurance coverage at reasonable rates (or at all), or that any coverage it or the relevant operator obtains, and any proceeds of insurance, will be adequate and available to cover any claims arising.

The Group may become subject to liability for pollution or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. Any indemnities the Group may receive from sub-contractors, operators, joint venture partners or prior asset owners under relevant acquisition documentation may be difficult to enforce if such sub-contractors, operators, joint venture partners or prior owners lack adequate resources at the time of such claim. In the event that insurance coverage is not available or the Group's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, or indemnities are difficult to enforce, the Group may be required to fund any shortfall directly from its own financial resources. Any such uninsured or underinsured liability could impose an immediate and material cash obligation on the Group at a time when operating cash flow may already be under pressure.

The payment by the Group's insurers of any insurance claims may result in increases in the premiums payable by the Group for its insurance coverage and could adversely affect the Group's financial performance. In the future, some or all of the Group's insurance coverage may become unavailable or prohibitively expensive.

Any of the foregoing events could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.15 The Group is exposed to risks relating to its hedging activities

The Group carries out hedging activity to manage commodity price risk, to meet its contracted arrangements under its RBL Facility and to ensure sufficient funding for future capital allocation objectives. Derivative financial instruments held by the Group comprise oil and gas swaps and collars. Hedging policies could adversely affect the Group for a range of reasons including mismatch between the hedging instrument and risk for which protection is sought, mismatch between the nominal amount or duration of the hedging instrument and the related liability, default on obligation by the hedge counterparty, adjustment of the value of the derivatives including potentially the need to deposit additional cash or other assets as collateral in excess of original expectations, the high level of transaction costs, unanticipated tax consequences and subsequent exposure to financial risk.

The Group's derivative contracts may result in substantial losses or gains. For example, the Group reported net hedging income of \$75 million for the financial year ended 31 December 2025 (compared with a \$43 million expense in 2024) and net hedging expense of \$199.4 million for the six months ended 30 June 2026 (compared with a net hedging income of \$51.8 million for the six months ended 30 June 2025). There can be no assurance that the Group will not realise substantial losses or that the Group will realise substantial gains due to its hedging activities in the future.

The Group's ability to use hedging transactions to protect it from future hydrocarbon price volatility will be dependent upon commodity prices at the time it enters into future hedging transactions and its future levels of hedging and, as a result, its future net cash flows may be more or less sensitive to commodity price changes. In addition, if commodity prices remain low, the Group may not be able to replace its hedges or enter into new hedges at favourable prices to renew hedge positions as they mature.

No assurance can be given that the Group's hedging policies will sufficiently protect against volatility in commodity prices or that the Group will be able to put hedging in place with counterparties on acceptable terms in order to successfully implement its hedging policies. Furthermore, the Group may be restricted in

the counterparties from whom it can obtain hedging, or be unable to obtain hedging on acceptable terms, as a result of the arrangements the Group has in place for the Rhum field. If the Group is unable to hedge its hydrocarbon price risks effectively or experiences a loss as a result of its hedging activities, this could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations.

1.16 The Group may face unanticipated increased costs in connection with decommissioning obligations

The Group is obliged under UK law to dismantle and remove certain equipment, to cap or seal wells and generally to remediate production sites. Once a member of the Group is required to submit a decommissioning plan, that Group member will be jointly and severally liable for implementing that plan with former or current licence partners.

The costs of decommissioning are uncertain and may exceed the value of the long-term provision set aside to cover such decommissioning costs. The Group's financial statements as at 30 June 2026 include a provision of \$516 million for future decommissioning liabilities, based on internal and third party estimates of costs, inflation and discount rates. The ultimate costs of decommissioning wells and sites are difficult to predict accurately and may depend on a number of factors. For example, if the Group's cost estimates were increased by 10 per cent., and the applicable discount rate reduced by 1 per cent., the value of provisions could increase by approximately \$45.3 million. Further, when the Group acquires an oil and gas asset, where the relevant seller retains responsibility for decommissioning liabilities under the relevant acquisition documentation, if the relevant seller and/or the Group's licence partners default on their obligations, the Group could nonetheless remain liable for all decommissioning liabilities related to the relevant field. Members of the Group (and its licence partners) are parties to various decommissioning security arrangements relating to the Group's oil and gas assets in the UK, such that if a licence partner were to default on their decommissioning liabilities, the Group would be entitled to access the security provided by the defaulting party should the Group be made liable for additional decommissioning costs. However, there can be no assurance that the security provided will remain sufficient to cover the defaulting party's liabilities and that the Group's decommissioning liabilities would not increase significantly beyond the levels provided for in the Group accounts. There can also be no assurance that similar security arrangements relating to decommissioning liabilities would be available in jurisdictions outside of the UK in which the Group may determine to acquire assets in the future.

Decommissioning costs for the Group's assets require the posting of financial security, for example in the form of surety bonds and/or letters of credit. As at 30 June 2026, the Group held surety bonds totalling \$354 million to provide security for its decommissioning obligations. If the Group is unable to procure or renew financial security on commercially acceptable terms when required or at all, it risks being in default of its licence obligations and/or the terms of the relevant decommissioning security arrangements. The trustee under the relevant decommissioning security arrangements may also look to call on any existing security already posted.

Any substantial increase in estimated decommissioning liabilities or in the amount of financial security that the Group is required to provide under relevant decommissioning security agreements or acceleration in the timing of decommissioning could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations, as well as its ability to access capital.

1.17 The Group may be impacted by reduced demand for hydrocarbons and hydrocarbon-based products due to climate change concerns

The consequences of the effects of global climate change, and the continued political and societal attention afforded to mitigating the effects of climate change, may generate longer term reduction in the demand for hydrocarbon products and increase the pace of commercial deployment of alternative energy technologies and shifts in consumer preference for lower greenhouse gas emission products. The transition towards a low carbon worldwide economy is impacting both the supply and demand for unabated oil and gas. The availability and cost of alternative fuels may lead to a reduction in demand for carbon-based fuels, and lead to a decrease in the price at which the Group is able to sell its oil, gas and NGLs. This, in turn, may lead to a reduction in the Group's revenues and operating cash flow, and could have a material adverse impact on the Group's business, prospects, financial condition and/or results of operations.

2. RISKS RELATING TO LEGAL, TAX, ENVIRONMENTAL AND REGULATORY MATTERS

2.1 The Group operates in a regulated industry and has been, and may continue to be, affected by regulatory changes

The Group operates in an industry that is inherently hazardous and consequently subject to extensive regulations. The Group's current operations are, and its future operations will be, subject to licences, approvals, authorisations, consents and permits from governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil and other hydrocarbons, taxation and environmental and health and safety matters. As at the date of this document, the Group's oil and gas assets are primarily located in the UK, with a small amount from assets located on the Dutch Continental Shelf. Its operations are therefore principally subject to the laws and regulations of the UK, and the grant, continuity and renewal of the necessary approvals, permits, licences and contracts, including the timing of obtaining such licences and the terms on which they are granted, are subject to the discretion of the relevant governmental and local authorities in the UK.

UK authorities are authorised to, and do from time to time, inspect the Group's assets in order to verify compliance by the Group or its licence partners, as applicable, with relevant laws and the licences or the agreements pursuant to which they conduct their business. Fines may be imposed and a licence may be suspended, revoked or terminated, or enforcement action may be taken if a licence holder, or party to a related agreement, fails to comply with its obligations under such licence or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geological information or meet other reporting requirements. It may from time to time be difficult to ascertain whether the Group has complied with obligations under licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

Laws and regulations in the UK have changed significantly in the past and continue to be subject to ongoing reforms in response to changes to Government policy, technological innovations, economic shifts, environmental concerns and the focus on enhancing energy security. The technical requirements of applicable laws and regulations, including environmental laws and regulations, are becoming increasingly complex and stringent and therefore more difficult and expensive with which to comply. Compliance with such laws and regulations imposes substantial financial and administrative burdens on the Group. Moreover, the UK Government conducted a number of formal consultations during 2025 and 2026, relating to supplementary Environmental Impact Assessment guidance for assessing scope 3 carbon emissions, the future of the UK North Sea licensing regime and the security of supply of gas. The potential aggregate impact of new policies and their practical implementation on the Group's business remains unclear.

If the Group is unable to obtain, maintain or comply with necessary licences or comply with other applicable regulatory requirements, or if any of the licensing or other regulatory requirements to which the Group's business is subject are amended in a way that makes compliance with them more difficult or expensive, this could disrupt the Group's operations and reduce its revenues, materially and adversely affecting the Group's business, prospects, financial condition, cash flow and results of operations.

2.2 The Group has been, and may continue to be, materially adversely affected by changes to tax legislation, regulations and policies

In May 2022, the UK Government introduced the Energy Profits Levy (the "EPL"), a 25 per cent. surcharge on the profits of oil and gas producers in the UK, imposed as a result of the increases to commodity prices witnessed during 2022 as a result of the Russian invasion of Ukraine. The rate and duration of the EPL has been increased and extended a number of times since it was first introduced, most recently to 38 per cent. and 31 March 2030, respectively, with effect from 1 November 2024. In addition to the ring-fenced corporation tax (at 30 per cent.) and supplementary charge tax (of 10 per cent.), the ring-fence rate applicable to the Group's activities for the year ended 31 December 2025 was 78 per cent. The investment allowance previously available under the EPL with respect to qualifying expenditure (at a rate of 29 per cent.) was also removed, such that the allowance is not available for expenditure incurred on or after 1 November 2024. The rate of tax applicable to the Group has resulted in the reduction in the Group's after-tax cash flow and retained income. These measures also increase risk to the Group's future investment planning and may adversely impact the carrying value of the Group's oil and gas properties.

The UK Government more recently announced a new oil and gas revenue levy (the "OGRL"), previously referred to as the oil and gas price mechanism. The OGRL will permanently replace the EPL when it expires in 2030 or, if earlier, if both average oil and gas prices fall to, or below, threshold prices in the Energy Security Investment Mechanism. The OGRL will apply during periods of high prices and will be

charged at 35 per cent. on the portion of revenue from sales of oil or gas that exceed specified thresholds. There is no assurance that the UK Government will not review, change or amend fiscal regulations, rules or policies in the future (including to further extend or increase the EPL or to increase the rate of or otherwise change the OGRL). Further, changes in, or new interpretations of, tax laws could result in levels of taxation relief decreasing or no longer being available to the Group, or the Group no longer being able to utilise tax losses to offset future tax changes and payments in the manner or to the extent it wished. Any further increase to the Group's applicable tax rate, or any adverse change to the availability of tax reliefs, could reduce the after-tax cash flow available to the Group, and increase the risk to the Group's future investment planning, as well as materially and adversely impact the Company's ability to make distributions to Shareholders. Any such changes could also have a material adverse impact on the Group's business, prospects, financial condition and/or results of operations.

2.3 The Group may be adversely impacted by climate change abatement legislation

The continued political attention to the role of human activity in climate change and potential mitigation through regulation could have a material impact on the hydrocarbon industry and on the Group's business, financial condition and results of operations. International agreements, national and regional legislation, and regulatory measures to limit greenhouse gas emissions are currently in various stages of discussion or implementation. In the UK, the UK Parliament passed legislation in June 2019 enshrining in law a target for at least a 100 per cent. reduction in greenhouse gas emissions (compared to 1990 levels) in the UK by 2050 (also known as a "net zero target"). The North Sea Transition Authority has also set out certain requirements related to basin-wide emissions reductions on holders of, and operators under, petroleum licences and other relevant persons which seek to support the move towards the net zero target.

Further, the Group currently participates in both the UK's Emissions Trading System ("UK ETS") and the EU Emissions Trading System ("EU ETS"). Both the UK ETS and EU ETS systems operate by setting a cap on the total amount of certain greenhouse gases that can be emitted by sectors covered by the relevant system and include the upstream oil and gas production sector. Within the cap, participants can receive free allowances and/or buy emissions allowances, which they can trade with other participants as needed. It is expected that, over time, the price of allowances under each of the UK ETS and EU ETS systems will rise and the number of free allowances allocated will reduce. This could leave the Group and others in the industry exposed to higher costs for participating in, and complying with, the UK ETS and EU ETS. The cost of reducing, avoiding or capturing emissions could be significant, and some emissions may not be capable of being reduced, avoided or captured, thereby requiring to be accounted for via the purchase of allowances at potentially increasing prices. Further, the UK ETS system and EU ETS systems are currently separate systems, and allowances are not interchangeable, which increases compliance costs for the Group. Although the UK Government and European Commission have announced their intention to pursue a link between the two systems, no agreement has yet been finalised as at the date of this document.

The evolution of such climate change abatement legislation or the further tightening of regulatory initiatives could have a material adverse effect by increasing the costs associated with complying with related operational regulations and disclosure requirements. The level of expenditure required to comply with these laws and regulations is difficult to predict accurately.

Any material increase in compliance costs or reduction in hydrocarbon demand resulting from climate change legislation could reduce the Group's revenues and cash flow and could have a material adverse impact on the Group's business, prospects, financial condition and/or results of operations.

2.4 The Group may be impacted by increasing scrutiny around, and changes in investment trends due to, ESG-related considerations

In recent years, increasing attention has been given to corporate activities related to ESG-related matters in public discourse and the investment community.

The Group supports the targets set out in the 2021 UK North Sea Transition Deal to reduce UKCS basin CO₂e production emissions by 25 per cent. by 2027 and 50 per cent. by 2030, and to become net zero by 2050, compared to a 2018 baseline. Further, Serica supports the World Bank's goal of zero routine flaring by 2030. A failure or perceived failure by the Group to deliver on its stated climate change commitments, or to adopt a strategy consistent with evolving investor or end-customer expectations and standards or to respond appropriately to the growing concern relating to ESG-related issues, regardless of whether there is a legal requirement to do so, could cause reputational harm to the Group's business, increase its risk of litigation, and could have a material adverse effect on its results of operations. The long-term viability of the business may be in question if the Group is unable to maintain a strategy and portfolio that is

demonstrably resilient to evolving market conditions, regulatory requirements and social expectations related to climate change and the energy transition.

Moreover, organisations that provide information to investors on corporate governance and related matters have developed ratings systems for evaluating companies on their approach to sustainability matters. These ratings are used by some investors to inform their investment and voting decisions. Unfavourable sustainability ratings may lead to increased negative investor sentiment toward the Group and its industry and to the diversion of investment to other companies or industries, which could adversely affect the price of the Ordinary Shares and the Group's access to capital and its ability to refinance existing debt, including the Nordic Bond, on acceptable terms. Institutional lenders may also decide not to provide funding for oil and gas companies based on climate change related concerns, leading to fewer banks and other financial institutions lending to the sector and, accordingly, making it more costly and at times more difficult to obtain financing. Any of the foregoing events may have a material adverse effect on the Group's business, prospects, results of operations and/or financial condition.

Further, non-governmental organisations and shareholder activists have, in the past, initiated, and are expected to, in the future, initiate, climate change litigations against corporate entities both in the extractive industries and in support sectors, such as banks and financial institutions and regulators. It is difficult to predict what litigation might arise in the future or the prospects of success without knowing the terms of the arguments advanced. No assurance can be given that the Group will not be named in climate change related proceedings in the future and, if named, what the outcome of any such proceedings might be.

2.5 The Group's operations are subject to the risk of litigation

From time to time, the Group may be subject, directly or indirectly, to legal claims arising out of its activities that, if not settled or otherwise disposed of, could result in litigation or arbitration. Historically, examples of the nature of potential claims that have arisen have been in respect of personal injury claims, employment matters and commercial contract disputes. Damages claimed under any such litigation may be material or may be indeterminate, and any material adverse litigation outcome could have a material adverse impact on the Group's business, prospects, financial condition, cash flow and/or results of operations.

While the Group assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defend against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows and ability to access capital.

3. RISKS RELATING TO THE OPERATION OF THE RHUM FIELD

Serica Energy (UK) Limited, a wholly-owned subsidiary of Serica, holds a 50 per cent. interest in the Rhum gas field and is the operator of the field. The remaining non-operated 50 per cent. in the licence has been owned by Iranian Oil Company (U.K.) Limited ("IOC") since 1972. Prior to a restructuring of the ownership structure of IOC (the "IOC Restructure"), IOC was a subsidiary of Naftiran Intertrade Co. (NICO) Limited ("NICO"). NICO is a subsidiary of National Iranian Oil Company ("NIOC"), the state oil company of Iran. The IOC Restructure had the effect of separating IOC and its interest in the Rhum field from any Iranian ownership, management or economic interest until such time as US sanctions on IOC's previous Iranian owners are lifted.

The IOC Restructure was necessitated by the US withdrawal from the 2015 Joint Comprehensive Plan of Action, which had granted (for a time) Iran some sanctions relief in return for restrictions on Iran's nuclear programme, and the tightening of US sanctions on Iran in May 2018. IOC, NICO, and NIOC are on OFAC's Specially Designated Nationals and Blocked Persons list (SDN List), which means they are subject to property-blocking sanctions in the US. This further means that the US sanctions against Iran prohibit US persons and non-US entities owned or controlled by US persons from engaging in any transactions or dealings with or involving IOC or the Rhum field, except as licensed by OFAC.

OFAC has issued multiple licences in respect of Rhum without interruption since 2013 including for the entire period in which Serica has owned its interest in, and operated, the field (since late 2018). Serica currently operates under an OFAC License and secondary sanctions assurance renewed in February 2025 and valid until the end of February 2027. Subject to certain conditions, the OFAC License authorises certain US persons and non-US entities owned or controlled by US persons to supply certain goods, services, and support for the operation, maintenance, and production of the Rhum field. OFAC has also provided written assurances that non-US persons will not be exposed to US secondary sanctions for their

activities and transactions involving the Rhum field so long as the OFAC License remains in effect and the conditions of the OFAC License are met.

3.1 Maintaining production from the Rhum field depends on having an OFAC License and secondary sanctions assurance in place to protect suppliers to the Rhum field from US sanctions on Iran

The current OFAC License and secondary sanctions assurance is valid until the end of February 2027. The Company notes that, on 10 September 2026, OFAC issued a ‘Statement of Licensing Policy on Iran-Related Requests’ that establishes a presumption of denial for licence applications seeking authorisation to engage in activities that are otherwise prohibited pursuant to US sanctions. Under this Statement of Licensing Policy, Iran-related specific licenses may only be issued as required by law or in exceptional and urgent circumstances, such as risk to life, limb, or environmental safety. The Company intends to apply for the renewal of the current OFAC License and secondary sanctions assurance prior to their expiry at the end of February 2027. While the Company believes, based on its experience since acquiring its interest in the Rhum field in 2018, among other things, that there are reasonable grounds for the current licence and assurances to be renewed, there can be no guarantee of such renewal. OFAC could decline to renew (or could withdraw, at any time, the authorisations granted under) the current licence and/or assurances. Furthermore, the OFAC License and assurance could be terminated if the conditions of the licence do not continue to be met. Were this to occur, it is likely that production from the Rhum field, which produced 10,900 boepd of gas net to Serica in 2025 (2024: 13,700 boepd) and representing approximately 40 per cent. of the Group’s average production in 2025 (2024: approximately 40 per cent.), would have to be stopped immediately.

The costs of operating the Bruce platform are shared with the Rhum owners under a transportation and processing agreement. If the shut-in of Rhum persisted, in the long-term the increase in the proportion of costs borne by the Bruce and Keith fields could lead to an earlier than otherwise anticipated cessation of production from those fields, which would materially reduce the Group’s production and revenues and could have a material adverse effect on the Group’s business, prospects, financial condition and/or results of operations.

3.2 Future changes to US, UK and/or EU sanctions may impact the Group’s operations at the Rhum field

In September 2025, the UK and EU reimposed certain sanctions on Iran and designated certain entities as targets of asset freezing sanctions. These entities included NIOC and NICO, which, prior to the IOC Restructure, had been direct and indirect owners of IOC. However, based on legal advice the Company has received relating to UK and EU sanctions as at the date of this document, IOC is not currently designated on any UK or EU sanctions lists and is not considered to be owned or controlled, directly or indirectly, by NIOC, NICO or any other sanctioned entity for the purposes of UK or EU sanctions such that UK or EU sanctions would apply to IOC. Furthermore, based on legal advice the Company has received relating to UK and EU sanctions as at the date of this document, the expansion of the non-asset freezing UK and EU sanctions on Iran in 2025 and 2026 are not understood to be relevant to the Rhum field.

There can be no assurance that current arrangements in respect of the Rhum field would be effective, or that the US, UK or EU authorities would not, in the future, impose conditions and/or requirements with which it would be onerous for the Company to comply. If the UK and/or EU were to impose sanctions impacting on the Rhum field’s operations, or the US were to alter their current sanctions regime, and arrangements are not, or cannot be put, in place that would effectively protect the Group and/or suppliers to the Rhum field against the imposition of such sanctions, it is likely that production from the Rhum field would have to be suspended. This could lead to a reduction in the Group’s overall production and, in light of the cost-sharing arrangements in place with the Rhum owners in relation to the Bruce platform, an increase in the proportion of costs borne by the Bruce and Keith fields in the long-term. This, in turn, could lead to an earlier than anticipated cessation of production from those fields. Any of the foregoing could have a material adverse effect on the Group’s business, prospects, financial condition, cash flow and/or results of operations.

3.3 Suppliers could elect not to supply goods and/or services to Rhum

It is possible that certain suppliers on which Rhum depends for safe operations could, in the future, elect to withhold goods and/or services, despite being protected from sanctions under the arrangements in place described above. If this were to occur, the Group may be forced to seek alternative suppliers and/or goods for the operation of Rhum, which may not be available on a timely basis or on acceptable commercial terms. Any delay in obtaining, or failure to obtain, the necessary goods and/or services on commercially acceptable terms could lead to a disruption to the Group’s operations and production at the Rhum field. If a

shut-in of Rhum persisted, in light of the cost-sharing arrangements in place with the Rhum owners in relation to the Bruce platform, this could lead to an increase in the proportion of costs borne by the Bruce and Keith fields in the long-term and in turn, an earlier than anticipated cessation of production from those fields. Any disruption to Rhum operations could have a material adverse effect on the Group's business, prospects, financial condition, cash flow and/or results of operations.

4. RISKS RELATING TO ADMISSION AND THE ORDINARY SHARES

4.1 The market price of the Ordinary Shares could be subject to volatility

The market price of the Ordinary Shares may fluctuate as a result of a variety of factors, including, but not limited to, the materialisation of one or more of the risk factors referred to above. Sales of a substantial number of Ordinary Shares by Shareholders, or the perception that such sales might occur, could adversely affect the market price of the Ordinary Shares. Further, the market price could also be adversely affected by developments unrelated to the Group's operating performance, many of which are outside of the control of the Group, such as the operating and share price performance of other companies that investors may consider comparable to the Group, speculation about the Group in the press or the investment community, unfavourable press, strategic actions by competitors (including acquisitions and restructurings), changes in market conditions, regulatory changes and broader market volatility and movements. Any or all of these factors could result in material fluctuations in the price of the Ordinary Shares, which could lead to investors getting back less than they invested or a total loss of their investment.

4.2 A liquid market for the Ordinary Shares may not be maintained

Admission should not be taken as implying that there will continue to be a liquid market for the Ordinary Shares. There is no guarantee that there will be sufficient liquidity in the Ordinary Shares to sell or buy any number of Ordinary Shares at a certain price level. Whilst the Company's Ordinary Shares have been admitted to trading on AIM for many years, Serica cannot predict the extent to which an active market for the Ordinary Shares will be sustained. An illiquid market for the Ordinary Shares may result in lower trading prices and increased volatility, which could adversely affect the value of any investment.

The trading market for the Ordinary Shares may also continue to be influenced by the research and reports that industry or securities analysts publish about Serica and/or its business. If securities or industry analysts do not publish research or reports about Serica's business, or if they downgrade their recommendations, the market price of the Ordinary Shares and their trading volume could decline.

4.3 The issuance of additional Ordinary Shares in the Company in connection with future acquisitions, any share incentive or share option plan or otherwise may dilute all other shareholdings

The Group may seek to raise financing to fund future acquisitions and other growth opportunities. The Company may, for these and other purposes, issue additional equity or securities convertible into equity securities. As a result, holders of Ordinary Shares may suffer dilution in their percentage ownership, or the market price of the Ordinary Shares may be adversely affected.

4.4 The Company's ability to pay dividends in the future depends, among other things, on the Group's financial performance and capital investment requirements

There can be no guarantee that the Group's historical performance will be repeated in the future, particularly given the competitive nature of the industry in which it operates, and its profit and cash flow may significantly underperform market expectations. If the Group's cash flow underperforms market expectations, then its capacity to pay the level of dividend or to pay a dividend at all will suffer. Any decision to declare and pay dividends will be made at the discretion of the Directors and will depend on, among other things, applicable law, regulation, restrictions on the payment of dividends in the Group's financing arrangements, the Group's financial position in light of its anticipated working capital and investment plans, the Company's distributable reserves, working capital requirements, finance costs, general economic conditions and other factors the Directors deem significant from time to time. There can be no assurance that the Company will pay dividends or, if it does choose to pay dividends, as to the amount of such dividends.

4.5 The Ordinary Shares will no longer benefit from certain UK tax reliefs available in relation to companies admitted to trading on AIM

Following Admission, the Ordinary Shares will not benefit from certain UK inheritance tax reliefs and exemptions and certain other UK tax reliefs and exemptions that may be applicable to shares traded on

AIM. In particular, shares admitted to trading on AIM may qualify for business relief for inheritance tax purposes, which (with effect from 6 April 2026) is available at a rate of 50 per cent. Following Admission, the Ordinary Shares will be admitted to the Official List and will be traded on the Main Market, and will not qualify for such relief (as may have otherwise been the case, had the Ordinary Shares continued to be traded on AIM). Accordingly, there may be adverse tax consequences in relation to holding (or continuing to hold) an investment in the Ordinary Shares. This could lead to sales of Ordinary Shares, which could depress the price of the Ordinary Shares. The taxation of an investment in the Ordinary Shares depends on the individual circumstances of Shareholders, and Shareholders who have any concerns in relation to the taxation of their Ordinary Shares following Admission should consult their own appropriate professional advisers in respect of such matters. This document is not a substitute for independent tax advice and does not purport to give such advice.

IMPORTANT NOTICES

1. GENERAL

This document comprises a simplified prospectus for the purposes of PRM 7 and is issued in compliance with the UK Listing Rules.

This document does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue any securities by any person. This document is issued solely in connection with Admission. No offer of Ordinary Shares or any other securities is being made in any jurisdiction in connection with Admission. No action has been taken by the Company or by Peel Hunt that would permit an offer of the Ordinary Shares or rights thereto in any jurisdiction.

The distribution of this document into jurisdictions other than the United Kingdom may be restricted by law. Neither this document nor any advertisement may be distributed or published in any other jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this document comes are required by the Company and Peel Hunt to inform themselves about and observe any such restrictions. Any failure to comply with any such restrictions may constitute a violation of the securities laws or regulations of such jurisdictions. No action has been taken by the Company or by Peel Hunt that would permit possession or distribution of this document or any other publicity material in any jurisdiction where action for that purpose is required, other than in the United Kingdom.

Investors should only rely on the information in this document. No person has been authorised to give any information or to make any representations other than those contained in this document in connection with Admission and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors or Peel Hunt. Furthermore, the Company and the Directors accept no responsibility for the accuracy or completeness of any information reported by the press or other media, or the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media regarding Admission, the Group or the Ordinary Shares. The Company and the Directors make no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication.

The Company does not undertake to update this document, unless required pursuant to PRM 10. Neither the delivery of this document nor Admission shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this document or that the information in this document is correct at any time subsequent to its date.

The contents of this document are not to be construed as legal, business or tax advice. Recipients of this document should consult their own lawyer, financial adviser or tax adviser for legal, financial or tax advice in relation to any action in respect of the Ordinary Shares. In making any investment decision, each investor must rely on their own examination, analysis and enquiry of the Company, including the merits and risks involved.

No representation is made by any of the Company, Peel Hunt or any of their respective affiliates, directors, officers, employees or advisers to any shareholder or prospective offeree or acquirer of the Ordinary Shares regarding the legality of an investment in the Ordinary Shares by such shareholder or prospective offeree or acquirer under the laws applicable to such person.

Apart from the responsibilities and liabilities, if any, which may be imposed on Peel Hunt by FSMA or the regulatory regime established thereunder, or under the regulatory regime of any jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, neither Peel Hunt nor any of its subsidiaries, holding companies, branches or affiliates nor any of their respective directors, officers, employees, agents or advisers, owes or accepts or shall assume any duty, responsibility or liability whatsoever (whether direct or indirect and whether arising in contract, in tort, under statute or otherwise) to any person in relation to the Admission or any other matter set out in this document or for any acts or omissions of the Company, and no representation or warranty, express or implied, is made by any of them as to the contents of this document, including its accuracy, completeness, verification or sufficiency, or for any other statement made or purported to be made by the Company, or on its behalf, or by Peel Hunt, or on its behalf, in connection with the Company, the Group, the Admission or the Ordinary Shares, and nothing in this document is, or shall be relied upon as, a promise or representation in this respect, whether or not to the past or future. To the fullest extent permitted by law, Peel Hunt and its subsidiaries, holding companies, branches and affiliates and their respective directors, members, officers, employees, agents, or advisers accordingly disclaim all and any duty, responsibility or liability whatsoever (whether direct or

indirect and whether arising in tort, contract, under statute or otherwise (save as referred to above)) which they might otherwise have in respect of this document or any such statement or otherwise.

This document has been prepared for the purpose of complying with English law and applicable regulations and the information disclosed may not be the same as that which would have been disclosed if this document had been prepared in accordance with the laws of jurisdictions outside of England.

2. INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This document includes statements that are, or may be deemed to be, “forward-looking statements”. The words “believe”, “estimate”, “target”, “anticipate”, “expect”, “intend”, “aim”, “plan”, “predict”, “continue”, “assume”, “positioned”, “may”, “will”, “should”, “could”, “would”, “shall”, “risk”, their negatives and other variations and other similar expressions that are predictions of or indicate future events and future trends identify forward-looking statements. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout this document and the information incorporated by reference into this document. In particular, the statements regarding the Company’s or the Group’s strategy, plans, objectives, goals and other future events or prospects are forward-looking statements. By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances and other factors that may or may not occur in the future and are in many cases beyond the Company’s or the Group’s control. Forward-looking statements are not guarantees of future performance. The Company’s and the Group’s actual results, financial condition, financial performance and achievements, and the development of the industry in which they operate, may differ materially from those expressed or implied by such forward-looking statements. Such forward-looking statements are based on numerous assumptions regarding the Company’s and the Group’s present and future business strategies and the environment in which the Company and the Group will operate in the future. Further, certain forward-looking statements are based upon assumptions of future events which may not prove to be accurate. Given these uncertainties, investors should not place undue reliance on forward looking statements. In addition, even if the results, financial condition, financial performance or achievements of the Company and the Group, and the development of the industry in which they operate, are consistent with the forward-looking statements contained in this document, those results or developments may not be indicative of results or developments in subsequent periods.

The cautionary statements set forth above should be considered in connection with any subsequent written or oral forward-looking statements that the Company, or persons acting on its behalf, may issue. Factors that may cause the Company’s and/or the Group’s actual results to differ materially from those expressed or implied by the forward-looking statements in this document include but are not limited to the risks described under “*Risk Factors*” on pages 11 to 26 of this document.

Each forward looking statement speaks only as of the date it was made and is not intended to give any assurances as to future results. Furthermore, forward-looking statements contained in this document that are based on past trends or activities should not be taken as a representation that such trends or activities will continue in the future. Except as required by the FSMA, the UK Listing Rules, the DTRs, UK MAR, the PRM or the POATRs, the Company does not undertake any obligation to update or revise these forward-looking statements, and will not publicly release any revisions it may make to these forward-looking statements that may result from new information, events or circumstances arising after the date of this document.

For information on protected forward-looking statements, see paragraph 8 below.

3. PRESENTATION OF FINANCIAL INFORMATION

The audited consolidated financial statements of the Group as at and for the year ended 31 December 2025, which are incorporated by reference into this document as described in Part 8 (*Documents Incorporated by Reference*) of this document, have been prepared in accordance with UK-adopted International Accounting Standards (“UK IAS”). The unaudited condensed consolidated financial statements of the Group as at and for the six months ended 30 June 2026, which are incorporated by reference into this document as described in Part 8 (*Documents Incorporated by Reference*) of this document, have been prepared in accordance with International Accounting Standard 34 ‘*Interim Financial Reporting*’.

Unless otherwise stated, financial information for the Group has been extracted without material adjustment from the 2025 Annual Report and the 2026 Interim Results. Where information has been extracted from the audited consolidated financial statements of the Group, the information is audited unless otherwise stated.

Where information has been extracted from the unaudited consolidated financial statements of the Group, the information is unaudited.

4. NON-IFRS MEASURES

This document contains certain financial measures that are not defined or recognised under IFRS, including:

EBITDAX

EBITDAX represents earnings before interest, tax, depreciation and amortisation, impairments, transaction costs, unrealised hedging expenses, FX translation effects, asset revaluation effects, other non-cash gains or expenses and exploration expenditure. This is a useful indicator of underlying business performance and the definition adopted by Serica is consistent with that stipulated in the Group's RBL Facility.

The following table presents a reconciliation from Operating (Loss)/Profit to EBITDAX for each of the periods listed:

	For the six months ended 30 June 2026	For the financial year ended 31 December 2025
	\$'000	\$'000
Operating (Loss)/ Profit	(49,781)	111,974
Add back transaction costs	3,048	5,533
Add back DD&A	130,630	158,141
Add back depreciation in G&A	644	1,045
Add back E&E expenses and licence costs	—	1,247
Add back impairment of producing assets	5,820	—
Deduct contract revenue – other	—	(5,408)
Add back/ (deduct) unrealised hedging	110,843	(67,371)
Add back goodwill expense	95,582	—
Add back/ (deduct) FX effects/remeasurements	2,116	949
Add back share-based payments	1,648	3,523
EBITDAX	300,550	209,633

Post-tax CFFO

Post-tax CFFO comprises cash inflow from operations adjusted by the cash tax paid or received for the period. Serica considers that this is a useful measure of the cash generation of the business prior to the decisions made by the Group in relation to capital allocation and will utilise this measure in determining its dividend from FY 2026 and thereafter in line with its dividend policy. This measure was amended during FY 2026 to simplify reporting as part of the new dividend policy and for consistency of approach with peer companies' definitions. The FY 2025 post-tax CFFO below has been restated in accordance with the amended measure.

The following table presents a reconciliation from cash inflow from operations to post-tax CFFO for each of the periods listed:

	For the six months ended 30 June 2026	For the financial year ended 31 December 2025
	\$'000	<i>Restated</i> \$'000
Cash inflow from operations	270,493	179,946
Add taxation received / (paid)	9,126	63,358
Post-tax CFFO	279,619	243,304

Adjusted net cash/ (debt)

Adjusted net cash/ (debt) means the total cash and cash equivalents, including restricted cash, plus the level of interest bearing loans net of the carrying value of unamortised fees. This is an indicator of the Group's indebtedness and contribution to capital structure.

The following table presents a reconciliation from loans and borrowings to Adjusted net cash/ (debt) for each of the periods listed:

	As at 30 June 2026	As at 31 December 2025
	<i>\$ '000</i>	<i>\$ '000</i>
Interest bearing loans	(284,139)	(221,488)
Deduct unamortised fees	(15,861)	(9,512)
Cash and cash equivalents	324,451	18,840
Restricted cash	1,460	12,060
Adjusted net cash/ (debt)	25,911	(200,100)

The Directors believe that each of these measures provides important supplemental information with respect to the performance of the Group's business and operations.

These non-IFRS financial measures are unaudited and are not measures recognised under IFRS or any other generally accepted accounting principles. They do not have any standardised meaning prescribed under IFRS, and may be revised from time to time, and therefore may not be comparable to other similarly titled measures presented by other companies. These measures are intended to provide additional information and should not be considered in isolation or as a substitute for indicators prepared in accordance with IFRS.

Further information on the non-IFRS measures used in this document is set out on pages 169 to 170 of the 2025 Annual Report and pages 42 and 43 of the 2026 Interim Results, which are incorporated by reference into this document, as explained in Part 8 (*Documents Incorporated by Reference*) of this document.

5. PRESENTATION OF RESERVES AND RESOURCES

This document presents information concerning:

- certain assets acquired by the Group pursuant to acquisitions that completed in 2026 (namely, the TTE Asset Acquisition, the ONE-Dyas Asset Acquisition and the Spirit Energy Portfolio Acquisition), which have been evaluated by Sproule ERCE on a basis consistent with PRMS. Information on the reserves and resources in this document has been extracted from the Sproule ERCE CPR, which has an effective date of 30 June 2026. For further information, please see the Appendix (*Competent Person's Report*) of this document; and
- the Group's other reserves and resources, which are evaluated annually by the Group's reserve auditors, RISC Advisory, on a basis consistent with PRMS. Unless otherwise stated, information on the Group's reserves and resources (other than those relating to the assets acquired pursuant to the TTE Asset Acquisition, the ONE-Dyas Asset Acquisition and the Spirit Energy Portfolio Acquisition) in this document has been extracted from the 2025 Annual Report and the Company's reserves reports, which have been prepared as of 31 December 2025.

The effective date of the Sproule ERCE CPR is 30 June 2026. The Spirit Energy Portfolio Acquisition (that is, the acquisition of the Greater Markham Area, Cygnus, Clipper South, Galleon, Eris and Ceres assets referred to in the Sproule ERCE CPR) has completed since such date. The Company is not aware of any material changes that have occurred since the date of the Sproule ERCE CPR the omission of which would make the Sproule ERCE CPR misleading.

The information on reserves and resources in this document is based on economic and other assumptions that may prove to be incorrect. Prospective investors should not place undue reliance on the forward-looking statements in this document or on the ability of the information on reserves and resources in this document to predict actual reserves and resources.

Typical to the industry in which the Group operates, there are a number of uncertainties inherent in estimating quantities of 2P reserves and 2C resources. The reserves and resources information on the Group

is based on the Company's assessments of the Group's asset base and its opinion as to the reasonableness of such assessments and represent estimates only. The assessment of reserves and resources is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserves estimate or resources estimate is a function of a number of variable factors and assumptions, many of which are beyond the Group's control, including the quality of available data and of engineering and geological interpretation and judgement and assumptions as to oil price. As a result, estimates of different reserve auditors may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to the inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of reserves estimates, the initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, estimates of contingent and prospective resources are by their nature more speculative than estimates of proved reserves and would require substantial capital spending over a significant number of years to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from the Group's assets will differ substantially. The significance of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Thus, investors should not place undue reliance on the accuracy of the reserves and resources information in this document in predicting actual reserves or resources or on comparisons of similar estimates/information concerning companies established in other economic systems. In addition, except to the extent that the Group acquires additional properties containing 2P reserves or conducts successful exploration and development activities, or both, the Group's 2P reserves will decline as reserves are produced.

"2P reserves" are defined as those quantities of hydrocarbons which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations (**"proved reserves"**), plus those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves (**"probable reserves"**); it is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P reserves).

References to **"2C resources"** are to the best estimate contingent resources, for which there should be at least a 50 per cent. probability (P50) that the quantities actually recovered will equal or exceed the best estimate but are not yet considered commercially viable due to one or more contingencies.

Unless otherwise indicated, all production figures are presented on a net to the Group's working interest basis.

6. MARKET AND INDUSTRY DATA

Market data and certain industry forecasts used in this document were obtained from internal surveys, reports and studies, where appropriate, as well as market research, publicly available information and industry publications.

Industry publications generally state that the information that they contain has been obtained from sources believed to be reliable but that the accuracy or completeness of such information is not guaranteed and that the projections they contain are based on a number of significant assumptions. Similarly, internal surveys, reports and studies and market research, while believed by the Company to be reliable and accurately extracted by the Company for the purposes of this document, have not been independently verified and the Company makes no representation as to the accuracy of such information. The Company confirms that all third party information, data and statistics contained in this document have been accurately reproduced and, so far as the Company is aware and able to ascertain from the information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading.

7. PROFIT FORECAST OR PROFIT ESTIMATE

Other than as described in Section B to Part 3 (*Selected Financial Information*) of this document, no statement in this document is intended as a profit forecast or profit estimate. No statement in this document should be interpreted to mean that earnings per Ordinary Share for the current or future financial years would necessarily match or exceed the historical published earnings per Ordinary Share.

8. PROTECTED FORWARD-LOOKING STATEMENTS

The statement in underline and italic font in Section B to Part 3 (*Selected Financial Information*) of this document in relation to the FY 2026 Post-Tax CFFO Guidance constitute “protected forward-looking statements” for the purposes of PRM 8. No guarantee can be given that the Group’s post-tax CFFO for FY 2026 will prove to be accurate. Under the POATRs, a different liability standard is applied for protected forward-looking statements compared with other information in this document which will make it more difficult to succeed in a claim for compensation in the event of any loss caused by a protected forward-looking statement. The Company and the Directors are under no obligation to update any protected forward-looking statements in this document, except in accordance with existing obligations where those apply.

9. NO INCORPORATION OF WEBSITE

The contents of the Company’s website (www.serica-energy.com) and the contents of any website accessible from hyperlinks on such websites or any other website referred to in this document (other than the information set out in Part 8 (*Documents Incorporated by Reference*) of this document) do not form part of this document and should not be relied on.

10. CURRENCY PRESENTATION

Unless otherwise indicated, all references in this document to “pounds sterling”, “£” or “pence” are to the lawful currency of the UK, to “Euro”, “EUR” or “€” are to the lawful currency of a member state of the EU participating in the European Monetary Union, and to “US dollar”, “\$” or “USD” are to the lawful currency of the US. The Group prepares its financial information in US dollars, the currency which the Group elected to use as its presentational currency with effect from 1 January 2024.

11. ROUNDING

Percentages and certain amounts included in this document have been rounded for ease of presentation. Accordingly, figures shown as totals in certain tables may vary from the actual arithmetic totals of the figures that precede them. In addition, certain percentages presented in the tables in this document reflect calculations based upon the underlying information prior to rounding, and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, and may not add up to 100 per cent.

12. TECHNICAL TERMS AND DEFINED TERMS

Certain terms used in this document, including capitalised terms and certain technical and other terms are explained in Part 9 (*Technical Terms*) and Part 10 (*Definitions*) of this document.

DIRECTORS, COMPANY SECRETARY AND ADVISERS

Directors	David Michael Latin (<i>Chair</i>) Christopher Martin Cox (<i>Chief Executive Officer</i>) Martin Francis David Copeland (<i>Chief Financial Officer</i>) Katherine Jane Coppinger (<i>Senior Independent Director</i>) Michiel Soeting (<i>Independent Non-Executive Director</i>) Robert Stephen Lawson (<i>Non-Executive Director</i>) Guillaume Jean Roger Vermersch (<i>Non-Executive Director</i>) Kaat Juliana Van Hecke (<i>Independent Non-Executive Director</i>) Sian Lloyd Rees (<i>Independent Non-Executive Director</i>)
Company Secretary	John Stockdale
Registered Office of the Company	4th Floor 72 Welbeck Street London United Kingdom W1G 0AY
Sponsor	Peel Hunt LLP 100 Liverpool Street London United Kingdom EC2M 2AT
Legal Advisers to the Company as to English law	Ashurst Perkins Coie UK LLP London Fruit & Wool Exchange 1 Duval Square London United Kingdom E1 6PW
Legal Advisers to the Sponsor as to English law	Pinsent Masons LLP 30 Crown Place London United Kingdom EC2A 4ES
Auditor and Reporting Accountants	BDO LLP 55 Baker Street London United Kingdom W1U 7EU

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

The dates and times given in the table below and throughout this document in connection with the Admission are indicative only and are based on the Company's current expectations and are subject to change. References to a time of day are to London time unless otherwise stated.

EVENT	TIME AND/OR DATE
Publication of this Prospectus	21 October 2026
Cancellation of admission to trading of Ordinary Shares on AIM	By 8.00 a.m. on 27 October 2026
Admission and commencement of dealings in the Ordinary Shares on the Main Market of the London Stock Exchange	By 8.00 a.m. on 27 October 2026

PART 1

BUSINESS OVERVIEW

1. OVERVIEW

Serica is a British independent upstream oil and gas exploration, development and production company with a portfolio of assets located principally on the UK Continental Shelf, with a minor presence on the Dutch Continental Shelf. It is incorporated in England and Wales with offices in London and Aberdeen. Serica has a two-pronged strategy for growth with value delivered by M&A through the acquisition of both new production assets and further organic opportunities, and enhanced by operational and subsurface expertise.

Serica has a balanced and diversified portfolio delivering from multiple hubs and associated infrastructure on the UK Continental Shelf and the Dutch Continental Shelf. During 2025, the Company announced a number of acquisitions, including the acquisition of Prax Upstream, which completed in December 2025, the associated acquisitions of the West of Shetland assets and interests in the Catcher and Golden Eagle Area Development fields (which completed in 2026) and the acquisition of a portfolio of Southern North Sea assets from Spirit Energy, which completed on 1 October 2026.

As at the date of this document, Serica holds interests in 30 producing fields mainly focused around four hubs:

- the Bruce Hub, which comprises the Bruce, Keith and Rhum fields (“**BKR**”) which feed into the Bruce Platform in the UK Northern North Sea that Serica operates;
- the Triton Hub, which comprises a mix of operated and non-operated fields tied back to the Triton FPSO operated by Dana Petroleum Limited (“**Triton**” or “**Triton Hub**”);
- the West of Shetland Hub, a Serica-operated hub which comprises the Greater Laggan Area and associated infrastructure and Shetland Gas Plant; and
- the Southern North Sea, which comprises a mix of operated and non-operated gas fields in the Greater Markham Area and across the Southern North Sea, including the Cygnus field, one of the largest producing gas fields on the UKCS.

Serica also has an operated interest in the producing Columbus field (UK Central North Sea) and a non-operated interest in the producing Erskine field (UK Central North Sea), Catcher field (UK Central North Sea) and Golden Eagle Area Development (UK Central North Sea). Serica’s production portfolio is complemented with a number of potential development projects such as Buchan Horst and a portfolio of exploration opportunities near Serica owned infrastructure including Skerryvore and Fynn Beaully.

Combined production net to Serica in the six months ended 30 June 2026 was 44,700 boepd, a material increase from the same period in the prior year due to higher portfolio uptime and the addition of production from the newly acquired West of Shetland assets. The Directors believe the Company remains on track to deliver 2026 production exit rate of approximately 65,000 boepd following completion of the Spirit Energy Portfolio Acquisition.

Serica has identified a range of short-cycle investment projects with the potential to support annual average production of over 50,000 boepd into the next decade. The investment programme is expected to deliver significant rates of return on average across the programme.

2. KEY COMPANY EVENTS

Serica was founded in 2004 although it can trace its roots back to 2000. Serica’s shares were admitted to trading on AIM in 2005 with a market capitalisation of £135 million.

Key events since Serica was admitted to AIM include the following:

- In June 2015, the Company changed its strategy from exploration and development in Asia and West Africa to focus on production in the UK North Sea, acquiring an 18 per cent. interest in the producing North Sea Erskine Field from BP.
- In 2018, the Company acquired its first interest in the Bruce, Keith and Rhum assets and associated infrastructure from BP. This was followed by a series of acquisitions of additional interests in the Bruce and Keith assets from Total E&P UK Limited (now known as NEO NEXT+ Energy E&P UK Limited), BHP Billiton Petroleum Great Britain Limited and Marubeni Oil & Gas (UK) Limited. Following completion of these acquisitions in November 2018, Serica held, and continues to hold, a

98 per cent. interest in the Bruce field, a 100 per cent. interest in the Keith field, and a 50 per cent. interest in the Rhum field.

- In December 2022, Serica entered into an agreement to acquire the entire issued share capital of Tailwind Energy Investments Limited (now, Serica Energy Investments Limited) from Tailwind Energy Holdings LLP (“**Tailwind Acquisition**”). Tailwind held a combination of producing fields tied back to the Triton FPSO and Ninian platform, an interest in the Columbus field tied back to Shearwater, and a portfolio of near-term development opportunities. In March 2023, Serica completed the Tailwind Acquisition which resulted in Mercuria, a significant shareholder in Tailwind, becoming an approximately 25.2 per cent. shareholder in Serica.
- In February 2024, Serica completed the acquisition of the 30 per cent. non-operated interests in the P2498 and P2170 licences (together the Greater Buchan Area) from Jersey Oil and Gas plc.
- In December 2024, Serica agreed to acquire a 50 per cent. working interest in licence P2400 (Skerryvore) and a 50 per cent. working interest in licence P2634 (Fynn Beaully) via the 100 per cent. acquisition of the shares in Parkmead (E&P) Limited from Parkmead Group plc. Following completion of the acquisition at the end of April 2025, Serica became the operator of both licences.
- In December 2025, Serica completed the acquisition of Prax Upstream Limited (“**Prax Upstream**”), as a result of which Serica acquired 100 per cent. of the interest in, and became the operator of, the Lancaster oil field. Prax Upstream had previously agreed to acquire, but had not yet completed, a 40 per cent. operating interest in the Greater Laggan Area and associated infrastructure, and operated licence interests in four near field exploration blocks from Total E&P (the “**TTE Asset Acquisition**”); and certain interests in the Catcher oil field and the Golden Eagle Area Development from ONE-Dyas (the “**ONE-Dyas Asset Acquisition**”). Following completion of Serica’s acquisition of Prax Upstream, Serica also completed the TTE Asset Acquisition and ONE-Dyas Asset Acquisition in March 2026 and June 2026, respectively.
- In October 2026, Serica completed the acquisition of a portfolio of Southern North Sea assets from Spirit Energy Limited, including a 15 per cent. working interest in the Cygnus gas field and a 25 per cent. interest in the Clipper South gas field.

3. REASONS FOR THE ADMISSION

Since being admitted to trading on AIM in 2005, the Group has demonstrated a strong commercial and financial track record, delivered shareholder returns and built a broad and supportive shareholder base. The Board believes that Serica is now of a size and scale to justify its transfer from AIM to the Main Market.

The Group has a proven track record of both organic and inorganic growth, and an ambitious management team. The Board views the transfer to the Main Market as the next step in the Group’s growth journey, further enhancing Serica’s corporate profile, as well as extending the opportunity to own its Ordinary Shares to a wider pool of UK and global investors. Following Admission, it is expected that the Company’s Ordinary Shares will be considered for inclusion in the FTSE 250 and FTSE All Share Indices at FTSE’s December 2026 review.

4. STRATEGY AND KEY STRENGTHS

4.1 Clear corporate strategy to deliver shareholder returns

Serica’s stated purpose is to contribute responsibly towards meeting the world’s energy needs through the safe and efficient production of hydrocarbons. To support this, it has a clear and well-defined strategy to deliver the Group’s goal of delivering value to shareholders through a mix of share price growth and direct shareholder returns. Serica has paid regular dividends to shareholders since July 2020. For FY 2026 and thereafter, Serica will target dividends of 15 to 30 per cent. of post-tax CFFO.

Serica aims to deliver its strategy through the creation of value in its assets and through M&A. Currently the Group’s assets are principally located on the UK Continental Shelf, with a small number of assets on the Dutch Continental Shelf. Serica sees scope to achieve its ambitions for growth both via consolidation of the UK upstream sector and diversification overseas in places where it can be competitive.

Although material investments in energy transition projects such as carbon capture and storage are not anticipated in the near term, the Group intends to screen and evaluate opportunities in this sector in

the UK with consideration being given to whether, and through what route, entry into this sector could be attractive for Serica.

4.2 Balanced and material levels of production with the potential to generate significant cashflows

Serica is in the top six of UK oil and gas companies (measured by production) in the UK North Sea. It has a diversified portfolio of both operated and non-operated mid-to-late life assets comprising 30 producing fields mainly focused around its four main hubs, the Bruce Hub, the Triton Hub, the West of Shetland Hub and the Southern North Sea. Serica has a balanced production mix of oil and gas.

Serica's aim is to deliver stable production from its producing assets and to offset natural decline through continuing to deliver maximum value from its portfolio of assets by unlocking high-quality subsurface opportunities to enable the Group to sustain or increase production. Serica believes there are further opportunities to optimise the performance of its existing producing assets by maximising recovery, boosting efficiency and, where safe to do so, reducing costs. The Group intends to use the latest industry technologies and practices (including horizontal drilling, well interventions and enhanced recovery techniques) to target increased recovery volumes and to maximise the recovery of in-place hydrocarbons. The Group has a particular focus on initiatives focused on maximising production efficiency and uptime.

Serica's portfolio has already demonstrated that it is capable of delivering sustained material production. The Company and the Directors believe it remains on track to deliver 2026 production exit rate of approximately 65,000 boepd following completion of the Spirit Energy Portfolio Acquisition. The Group is confident that future production based on normal operating efficiencies will continue to deliver significant free cash flow, which will enable Serica to fund organic growth prospects, while also delivering healthy returns to shareholders.

4.3 Significant organic growth potential to add incremental production

The Group's producing asset portfolio mainly comprises fields that have a long track record of production and the Group benefits from the well understood production performance characteristics of these established fields. Despite the maturity of the fields, considerable opportunities still exist within both the Bruce Hub and Triton Hub to increase the recovery of reserves to underpin future growth and create significant shareholder value. The Triton Hub infill drilling programme in 2024 – 2025 is an illustration of the quality of the opportunities that exist and of Serica's subsurface team's capabilities, with all five wells completed ahead of time and under budget, with results well within pre-drill expectations.

Serica is finalising a contract for a rig to undertake a multi-well drilling programme principally targeting infill wells and tie-backs across the broader Serica portfolio. The Company expects to commence drilling in Q3 2027, subject to all necessary consents and approvals. The programme is expected to begin with a three-well drilling programme at the Bruce field, which has an estimated pre-tax cost of around \$400 million. The Group may also use the rig for decommissioning work and/or an additional development well at another asset. It is anticipated that the charter and drilling programme will be funded from the Group's existing resources.

Serica has identified a range of short-cycle investment projects with the potential to support annual average production of over 50,000 boepd into the next decade. The investment programme is expected to deliver significant rates of return on average across the programme. Projects with the ability to add near-term production include:

- Bruce infill drilling, targeting the production of 18.6 mmboe of reserves, with first production expected within 12 months from the start of drilling;
- the Kyla field redevelopment, with 10.2 mmboe of reserves, able to be produced via a single horizontal well tied-back to the Triton FPSO; and
- the Edradour Royal Sovereign and Spinnaker (or ERSS) development (formerly referred to as Glendronach) and Tormore infill drilling, both of which are within the newly acquired Greater Laggan Area and, if developed, would be produced via the Serica-operated Shetland Gas Plant.

Should all of the identified short-cycle investment projects be delivered, a potential additional \$300-400 million pre-tax would be expected to be spent over the period to 2029, with production and returns from investment being delivered on a sequential basis as wells are tied in throughout the programme duration. Such additional expenditure is expected to be covered by the Group's free cash

flow in the period, on the basis of Serica's planning assumptions, including current consensus commodity prices.

4.4 Robust balance sheet, substantial tax losses and cash generative assets

Serica's balance sheet is robust with low net debt as well as moderate decommissioning liabilities and low level of other liabilities.

The Group has a strong history of cash generation despite an active investment programme. In the six months ended 30 June 2026, it generated positive free cash flow of \$184 million, which contributed to the Group moving from a net debt position to a net cash position. This was a material increase since 31 December 2025, due to robust production and higher commodity prices and the movement in cash for the period also benefited from the receipt of \$56 million on completion of the acquisition of West of Shetland assets from Total E&P.

The Group's liquidity position remains strong due to Serica's RBL Facility, completion of the \$300 million Nordic Bond as well as available cash. The RBL Facility is a revolving credit facility available in multiple currencies and provides significant liquidity to support future acquisitions and investment with a maturity out to 30 June 2032. The available borrowing capacity under the RBL Facility as at 30 September 2026 was \$458 million, significantly above the Group's current debt drawdown. Serica's net debt remains low, with an Adjusted net debt position of \$73 million as of 30 September 2026 (*30 June 2026*: Adjusted net cash of \$26 million) after cash outgoings during Q3 2026, which included the payment of the final dividend in respect of FY 2025, a cash tax payment in July 2026 and the completion payment in respect of the Spirit Energy Portfolio Acquisition.

As at 31 December 2025, following acquisitions in 2025, the Group had \$2.2 billion of fully recognised UK ring fence corporation tax losses, \$1.9 billion of supplementary charge losses and \$0.5 billion of Energy Profits Levy losses. The Group's ability to utilise these tax loss balances over time will help to offset the Group's future tax charges and tax payments.

The Group's decommissioning provision as at 30 June 2026 was \$516 million, an increase from \$251 million as at 31 December 2025, reflecting the result of consolidation of the asset acquisitions completed during the first half of 2026.

The robust balance sheet, liquidity, substantial tax losses and outlook of material cash flow in future years, is expected to enable Serica to continue to invest in its assets and to maintain its strong track record of returning capital to shareholders while retaining the ability to invest further in the portfolio and respond as required to unforeseen events.

The resilience of this strategy for the delivery of shareholder value was illustrated in 2025, when Serica returned \$85 million to investors, despite lower than forecast production as a result of unplanned outages at the Triton FPSO during 2025, while investing over twice that amount in the portfolio.

4.5 Track record of focused and disciplined value accretive M&A

Serica has a strong recent track record of identifying and executing successful M&A transactions. Serica's current asset portfolio was built through multiple transactions including the interests in the BKR fields in 2018, the acquisition of the Triton Hub, the Columbus and Orlando fields by the corporate acquisition of Tailwind Energy Investments (now Serica Energy Investments) in 2023, the acquisition of the 30 per cent. interest in the Greater Buchan Area in 2024 and the more recently completed acquisitions of the West of Shetland assets and Southern North Sea portfolio.

Further asset diversification through M&A remains a key focus for Serica. The Group will continue to seek meaningful acquisitions that complement its existing portfolio, that provide additional reserves and resources, and help to sustain and grow production whilst enhancing cash flows and value. Serica intends to continue employing a disciplined approach to evaluating M&A growth opportunities.

In addition to its ongoing UK focus, Serica intends to use its M&A expertise to identify value creating opportunities which are consistent with its overall strategy to provide geographical diversification that will reduce the Group's dependence on a single political jurisdiction.

4.6 Experienced management team and Board

Serica has re-shaped its management team and Board in recent years as the scale of the business has expanded with a new CEO, CFO and Chair appointed over the last two to three years. Chris Cox joined as CEO in July 2024 bringing the experience of running a multi-asset business, understanding the important maintenance and life extension challenges of mid-to-late life fields in the UK North Sea, delivering organic growth and building companies. Martin Copeland joined the business as CFO in February 2024 bringing the ability, energy and experience of identifying and executing value-accretive M&A transactions and with extensive capital markets experience. Other senior management appointments during 2025 include a Chief People Officer and a Chief Technical Officer, with a new Chief Operating Officer appointed in 2026.

Augmented by these appointments, Serica has a high-calibre executive leadership team with significant and diverse upstream oil and gas industry and finance and markets experience. The members of the Company's executive leadership team have decades of combined experience and have worked in various management and leadership roles across the industry. The management team has full-cycle capability with experience and expertise across exploration, development, operations and decommissioning.

Serica's Board of Directors has a diversity of skills and a range of experience across the oil and gas and wider energy sectors. This experienced leadership enables the Company to navigate the complexities of the oil and gas industry during a period of change.

4.7 Strong Health and Safety Record

Safety remains Serica's highest priority. The primary focus is protecting the health, safety and wellbeing of everyone who works for the Group and of Serica's contractors. To this end, Serica is committed to embedding an ingrained safety culture throughout the Group and to delivering continuous improvement in health and safety performance by implementing the best available international practices and procedures. With a strong focus on safety in all its operations, Serica ensures compliance with all relevant regulations and industry standards and good practice at a minimum, and Serica's Operations Management System provides an integrated and systematic approach to Health, Safety, Environmental and Quality management.

Serica's approach to health and safety performance is proactive, and one of Serica's key objectives is continual improvement of its safety performance. Should an event occur, it is swiftly investigated with learnings shared and recommendations taken forward. Serica's approach to the improvement notice issued in December 2024 by the Health and Safety Executive relating to gas emissions from the Bruce platform is a clear demonstration of the Group's commitment to strengthening the approach towards process safety. Serica's teams worked collaboratively to develop and implement a plan to address the deficiencies identified, and the Health and Safety Executive formally closed out the improvement notice in July 2025. Looking ahead, Serica will continue to strengthen process safety barriers through its dedicated Process Safety Improvement Plan while driving improvements in personal safety across all sites.

4.8 Culture of ESG

Serica is committed to producing oil and gas in a responsible manner that provides benefits to all our stakeholders while seeking continuous improvement in the emissions associated with that production. Serica is committed to the North Sea Transition Deal, aiming to reduce GHG emissions from the Group's assets, delivering transparent reporting of ESG performance, supporting the development of new energy technologies and positively influencing the wider industry. ESG performance is one of the key indicators used by the Board to assess overall corporate performance.

Serica's ESG Strategy provides overarching guidance on how Serica delivers its business in a socially and environmentally responsible way. Serica tracks its ESG performance data in line with globally recognised frameworks and externally verifies emissions data.

Serica's Scope 1 GHG emissions, which primarily comprise those generated by the Serica-operated Bruce installation to provide power and compression required to produce and export gas and oil from the BKR fields, totalled 195,746 tonnes of CO₂e in 2025 (a decrease of 15,472 tonnes compared to 2024). These emissions include fuel gas consumption, diesel usage, as well as emissions from flared and vented gas. 2025 emissions represented a reduction of 31 per cent. compared to the Group's 2018 baseline, the year that Serica became operator.

Serica is working to further reduce CO2 emissions on Bruce through the implementation of an Emission Reduction Action Plan (“ERAP”). The ERAP includes three key projects related to export gas compression and flare gas recovery.

Serica is also supporting the Triton FPSO operator’s development and implementation of an ERAP for this facility.

Serica is actively involved in a variety of industry-wide programmes to reduce GHG emissions from the UK North Sea, including the Emissions Reduction Action Plan Group (part of the Asset Stewardship Taskforce), Offshore Energy UK’s Atmospherics Technical Group and the Decarbonisation Forum, and the Accelerate Deployment workstream of the Technology Leadership Board (co-chaired by the NSTA and offshore industry).

5. Summary of reserves and resources

Serica’s oil and gas assets are principally located on the UK Continental Shelf. The Group’s reserves and resources comprise proven and probable reserves (2P) and the best estimate of contingent resources (2C). Serica’s subsurface team calculates reserves and resources for each field which are then reviewed with Serica’s internal assurance team and the Group’s external reserve auditors, RISC Advisory and Sproule ERCE, audit the work conducted on an annual basis.

Reserves and resources illustrate the long-term sustainability of Serica’s production, and potential within the portfolio. Serica aims to deliver its strategy through the creation of value in mid-to-late life assets and through M&A. In particular, Serica aims to extend the life of mature hydrocarbon fields through utilising its subsurface expertise and reservoir management techniques to maximise the value of mid-to-late life assets.

Serica’s reserves and resources for its current portfolio of assets broadly fall into four hubs, being the Bruce Hub (Bruce, Keith and Rhum), the Triton Hub (Bittern, Gannet E, Guillemot West and North West, Evelyn, Belinda and Kyla), West of Shetland Hub and Southern North Sea, as well as other producing assets (Columbus, Erskine and Orlando). Serica also has material 2C contingent resource held in Buchan project, in future Bruce drilling opportunities, as well as through future asset life extension activities on the Bruce platform, Triton FPSO and Erskine.

Reserves and resources information below relating to the Group’s assets other than those acquired by the Group pursuant to the TTE Asset Acquisition, the ONE-Dyas Asset Acquisition and the Spirit Energy Portfolio Acquisition in the West of Shetland Hub and Southern North Sea hub have been extracted from the 2025 Annual Report and the Company’s reserves reports. Reserves and resources information below relating to acquisitions that completed in 2026, namely, the assets acquired by the Group pursuant to the TTE Asset Acquisition, the ONE-Dyas Asset Acquisition and the Spirit Energy Portfolio Acquisition, have been extracted from the Sproule ERCE CPR.

Assets as at 31 December 2025

As at 31 December 2025 (mmboe)	2P 2025	2P 2024	2C 2025	2C 2024
Bruce Hub	61.2	69.8	55.8	33.3
Triton Hub	49.8	41.8	18.5	16.4
West of Shetland ⁽¹⁾	0.8	—	—	—
Other Production Assets	4.9	5.9	0.1	9.0
Greater Buchan Area	—	—	29.0	30.0
Total	116.8	117.5	103.4	88.7

Note:

(1) Comprising only the Lancaster Field as at 31 December 2025, which ceased production on 3 May 2026.

Asset Acquisitions Completed in 2026

As at 30 June 2026 (mmboe) ⁽¹⁾	2p	2C
West of Shetland	2.3	6.4
Southern North Sea	12.8	3.6
Other Production Assets	3.0	0.5
Total	18.1	10.6

Note:

(1) The figures for these assets are unaudited and have been extracted from the Sproule ERCE CPR, effective 30 June 2026. The reserves are assigned on the assumption that the Spirit Energy Portfolio Acquisition completed on 1 October 2026.

Reserves replacement was robust in 2025, supported by 10.2 mmboe being moved into 2P reserves due to the maturation of the Kyla redevelopment. This effectively offset the 10.1 mmboe of production in the year. Completion of the TTE Asset Acquisition, ONE-Dyas Asset Acquisition and Spirit Energy Portfolio Acquisition during 2026 also resulted in a significant increase to the Group's 2P reserves.

The increase in the Group's 2C resource position of its existing assets of 103.4 mmboe (from 88.7 mmboe as at the end of 2024) was driven by preliminary maturation of future Bruce drilling opportunities, delivering an 18.2 mmboe increase in 2C resources. The recently completed acquisitions of West of Shetland assets and Southern North Sea assets and, in particular, the acquisition of a 40 per cent. interest in the ERSS licence, West of Shetland, are key contributors to the increase in 2C resources as at 30 June 2026. These factors outweighed the relinquishment of the Mansell licence and transfer of Kyla from resources to reserves. The addition of Wagtail through the farm-in to the UK North Sea P2530 Licence also provided an uplift of 8.0 mmboe of 2C resources.

6. Overview of assets and principal activities

6.1 Overview

Serica holds interests in 30 producing fields, mostly focused around four main hubs. These are:

- the Bruce Hub in the UK Northern North Sea, which it operates;
- the Triton Hub, a mix of operated and non-operated fields tied back to the Triton FPSO;
- the West of Shetland Hub, a Serica-operated hub which comprises the Greater Laggan Area and associated infrastructure and Shetland Gas Plant; and
- the Southern North Sea, which comprises a mix of operated and non-operated gas fields in the Greater Markham Area and across the Southern North Sea, including the Cygnus field, one of the largest producing gas fields on the UKCS.

Serica also has an operated interest in the producing Columbus field (UK Central North Sea) and non-operated interests in the producing Erskine field in the UK Central North Sea, as well as the Catcher field and the Golden Eagle Area Development in the UK Central North Sea.

A summary of Serica's licence holdings is set out at paragraph 10 of Part 7 (*Additional Information*) of this document.

6.2 Bruce Hub

Serica holds a 98 per cent. interest in the Bruce field, a 100 per cent. interest in the Keith field and a 50 per cent. interest in the Rhum field. The Bruce Hub consists of three fields located approximately 350 km north-east of Aberdeen in water depths of up to approximately 120 metres. It consists of over 25 wells, three bridge-linked platforms and extensive subsea pipelines and infrastructure that tie-in Rhum, Keith and the Western area of Bruce facilities. Collectively, these assets provide a significant contribution to the UK gas demand. Production from the Bruce Hub averaged 16,100 boepd net to Serica in 2025 and 18,100 boepd net to Serica in HY 2026. The Bruce Hub resumed production after its scheduled annual maintenance period on 12 September 2026, with the Bruce Hub's production currently at around rates of 20,000 boepd (net to Serica).

- Bruce field (98 per cent.):* The Bruce field is a producing asset located in blocks 9/9a, 9/8a and 9/9b in the Northern North Sea. Gas is exported via the Frigg pipeline to the St Fergus terminal

and liquids exported via the Forties Pipeline System. Serica is the operator of the Bruce field; BP and Total E&P have each retained a 1 per cent. interest. Readiness work is underway in preparation for drilling the first new wells at Bruce since 2012. The Company is finalising a contract for a rig, and the Bruce drilling campaign is expected to start in Q3 2027.

- *Keith field (100 per cent.):* The Keith oil field is located in block 9/8a in the Northern North Sea, 6.4 kilometres to the southwest of Bruce. Serica is the operator of the Keith field. Following the completion of works at Bruce, the K1 well at the Keith field was brought back onto production towards the end of July 2025 for the first time since 2022.
- *Rhum field (50 per cent.):* The gas field is located in block 3/29a, 44 kilometres north of Bruce and is a subsea development tied back to the Bruce platform via an insulated pipeline. Serica is the operator of the Rhum field. See also paragraph 9 of this Part 1 (*Business Overview*) below for additional information relating to the arrangements in place in respect of the Rhum field.

6.3 Triton Hub

The Triton Hub consists of eight producing oil fields in the UK Central North Sea, located approximately 190 kilometres east of Aberdeen in water depths of up to approximately 90 metres. The fields which produce oil and gas via the Triton Floating Production Storage and Offloading (“FPSO”) vessel are Evelyn, Bittern, Guillemot West/ Northwest, Gannet E, Clapham, Saxon, Pict and Belinda, from which there has been limited production to date due to surface capacity issues at the Triton FPSO.

Dana Petroleum Limited (“Dana”) and Harbour Energy WPUK Limited (previously Waldorf Production UK Limited) (“Harbour Energy WPUK”) are Serica’s partners in the Triton Hub. Dana currently operates the Triton FPSO with the vessel owned 52 per cent. by Dana, 46.4 per cent. by Serica and 1.6 per cent. by Harbour Energy WPUK. Dana also operates the Bittern, Guillemot West and Guillemot Northwest, Clapham, Saxon and Pict fields. Serica is the operator of the Gannet E, Belinda and Evelyn fields. Production from the Triton Hub was significantly below potential in 2025 due to a number of unplanned outages caused by facilities issues with the Triton FPSO throughout the year. The Triton Hub produced 15,700 boepd (*H1 2025: 2,500 boepd*) net to Serica in the first half of 2026, benefitting from materially improved performance following significant maintenance work carried out in 2025. Whilst production performance at Triton has significantly improved in 2026, the scheduled annual summer maintenance period was extended beyond the originally scheduled period in 2026 to carry out additional remediation work with production currently expected to recommence from around the end of November 2026.

- *Bittern Field (64.63 per cent.):* Dana is the operator with a 32.95 per cent. interest and Harbour Energy WPUK (together with Harbour Energy Petroleum Resources Limited) holds a 2.42 per cent. interest. The Bittern oil and gas field is located in blocks 29/1a and 29/1b, 22 kilometres southeast of the Triton FPSO. The field was discovered in 1996 and has been developed through five production wells and two water injection wells via a subsea tie-back to the Triton FPSO.
- *Gannet E Field (100 per cent.):* Serica is the operator of Gannet E Field. The Gannet E Field, discovered in 1982, is situated in block 21/30c, 2.5 kilometres west of the Triton FPSO. The field was developed via three production wells and initially tied-back to the Gannet Alpha platform; first production was in 1998. Following a period of shut-in the wells were successfully re-instated and production from the field was achieved on schedule in Q4 2018. Subsequent work has added well capacity with five production wells now tied-back to the Triton FPSO.
- *Guillemot West / North West Fields (10 per cent.):* Dana is the operator with the remaining 90.0 per cent. interest. The Guillemot West (GW) and North West (GNW) Fields were discovered in 1983 and 1985 respectively and are located approximately 10 kilometres northwest of the Triton FPSO. The fields were developed in conjunction with the Bittern Field as a part of a combined development with production commencing from all three fields in April 2000.
- *Evelyn Field (100 per cent.):* Serica is the operator. Evelyn is an oil and gas field producing via the Triton FPSO. Evelyn is located in licence P1792 in block 21/30f of the UK Central North Sea and was originally discovered in 1984. The Evelyn Field Development Plan was submitted in 2020 with regulatory approval to develop the field being granted by North Sea Transition Authority in early 2021. Production from Evelyn commenced in September 2022.

- *Belinda Field (100 per cent.):* Serica is the operator of the Belinda Field with a 100 per cent. interest. The Belinda field is located in block 21/30f approximately 6 kilometres southeast of the Triton FPSO. Belinda was discovered in 1990 and appraised in 2016. Belinda has been developed as a single well tieback to the Triton FPSO. Production began in early 2026, but has been limited to date due to surface capacity issues at the Triton FPSO.
- *Kyla project (P2616) (100 per cent.):* Serica is the operator of the Kyla project with a 100 per cent. interest. The Kyla project, located in block 29/2c, is the redevelopment of a previously producing oil field, 20 kilometres southeast of Triton, shut-in due to the decommissioning of the Banff FPSO host facility, in 2020. Kyla contains 10.2 mmboe of 2P reserves and could be produced via a single horizontal well tied-back to Triton via Bittern, with the potential for first production within six months of the start of drilling. FEED commenced in February 2026 and has now concluded, and the environmental statement and field development plan have been submitted, in preparedness for potential drilling as part of the Company's wider organic growth drilling campaign.

6.4 West of Shetland Hub

Assets in the West of Shetland Hub were acquired by Serica through the Prax Upstream Acquisition and TTE Asset Acquisition. Further information on the reserves and resources and other technical information relating to the assets in the West of Shetland Hub are set out in the Appendix (*Competent Person's Report*) of this document.

The West of Shetland Hub is a Serica-operated hub comprising four gas fields in the Greater Laggan Area in the UK North Sea (Laggan, Tormore, Edradour and Glenlivet), the Shetland Gas Plant, the Lancaster field (which ceased production on 3 May 2026) and four infrastructure led exploration licences. Production from West of Shetland averaged 6,300 boepd net to Serica in the first half of 2026. Greater Laggan Area gas is evacuated from the Shetland Gas Plant through the Shetland Islands Regional Gas Export System (SIRGE) pipeline into the Frigg UK Association (FUKA) pipeline to the St Fergus terminal. The Shetland Gas Plant was commissioned in 2016 and is the newest onshore gas processing facility in the UK. The Shetland Gas Plant and associated infrastructure serves as the key gathering system for gas coming from the highly prospective West of Shetland basin. Serica expects that this will facilitate the exploitation of infrastructure-led development and exploration opportunities in the area including new sources of third-party throughput that offer the potential to extend the productive life of the Shetland Gas Plant.

- *Greater Laggan Area (40 per cent.):* The Greater Laggan Area comprises the Laggan, Tormore, Glenlivet, Edradour and ERSS fields, the onshore Shetland Gas Plant (together, the “GLA Assets”) and four infrastructure led exploration licences. The assets acquired under the TTE Asset Acquisition comprise Total E&P's entire 40 per cent. operated interest in the GLA Assets, as well as associated infrastructure usage rights and operated licence interests in four near field exploration blocks in the Shetland Gas Plant catchment area. The GLA Assets, located north-west of Shetland, comprise eight wells from four fields connected as subsea tiebacks to, and operated from, the Shetland Gas Plant. The Victory gas field, operated by Adura, is also tied back to the Shetland Gas Plant.
- *Laggan (40 per cent.):* The Laggan field is located in blocks 206/1a and 205/5d, 125 km north-west of the Shetland Islands on the UKCS. The field was discovered in 1986, with first gas achieved in 2016. 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 Shetland Gas Plant for processing and onward shipment.
- *Tormore (40 per cent.):* The Tormore field is located in blocks 205/5a and 205/4b, 125 kilometres north-west of the Shetland Islands on the UKCS. The field was discovered in 2007, with first gas achieved in 2016. 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 Shetland Gas Plant.
- *Glenlivet (40 per cent.):* Operated by Serica. The Glenlivet field is located approximately 45 kilometres north-east of Laggan in block 214/30a. The field was discovered in 2009. First gas was achieved in August 2017. Glenlivet 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 Shetland Gas Plant.

- *Edradour (40 per cent.):* Operated by Serica. The Edradour field is located in 36 km north-east of the Laggan field in block 206/4a. The field was discovered in 2011 and first gas was achieved in August 2017. Edradour was developed via a single production well tied back to a subsea manifold, which is connected via a spare line to the main Laggan twin pipeline to the Shetland Gas Plant. The field has been shut-in since late 2022.
- *Lancaster (100 per cent.):* Following completion of the Prax Upstream Acquisition in December 2025, Serica holds a 100 per cent. operated interest in the Lancaster Field. The field produced an average of just over 6,000 boepd prior to production ceasing on 3 May 2026, in line with expectations.

6.5 Southern North Sea

The acquisition of the Southern North Sea assets from Spirit Energy completed on 1 October 2026. This hub consists of a group of offshore natural gas fields located in the Greater Markham Area in the Southern North Sea (Serica-operated Markham, Chiswick, Grove, and Kew fields and non-operated J3C field) and straddles the maritime boundary between the United Kingdom and the Netherlands. Gas from these fields is processed across the J6A platform and exported via the WGT pipeline system to the Den Helder onshore terminal, where it undergoes separation, conditioning and distribution. Further information on the reserves and resources and other technical information relating to the assets in the Southern North Sea are set out in the Appendix (*Competent Person's Report*) of this document.

- *Cygnus Field (15 per cent.):* Cygnus is one of the largest producing gas fields in the UK North Sea, and is located in the Southern North Sea in blocks 44/11a, 44/11b and 44/12a, approximately 150 kilometres from the Lincolnshire coastline. The field, operated by Ithaca Energy, who owns the remaining 85 per cent., has a carbon intensity of 6 kgCO₂/boe, considerably below the UK North Sea average of 21 kgCO₂/boe, lowering the overall carbon intensity of the Serica portfolio. Cygnus is a mid-life field, having begun production in 2016. There are 11 wells, which produced a total of 4,000 boepd net to the acquired Spirit Energy stake in HY 2026, with an infill drilling campaign ongoing.
- *Markham (37 per cent.):* Operated by Serica. The Markham gas field is located in the Southern North Sea and straddles the UK-Netherlands median line. It is located in blocks 49/5a and 49/10b in the UK and blocks J03b, J03a, and J06a in the Netherlands. It was first discovered in 1984, with production in 1992. The field is no longer in production, with no further production anticipated.
- *Chiswick (100 per cent.):* The Chiswick gas field is located in UK block 49/4a in the Southern North Sea, approximately 18 km northwest of the Markham field, and was first discovered in 1984. Development wells tied back to the Markham J6A facility before the gas is exported. A total of twenty wells have been drilled, including exploration and appraisal wells, in the different fault blocks.
- *Kew (100 per cent.):* The Kew field is located in the Southern North Sea and is part of the Greater Markham Area hub. First production was achieved in 2014. Gas from the Kew field is routed via a 3-kilometre pipeline to the Chiswick installation.
- *Grove (92.5 per cent.):* The Grove field was discovered in 1971, with first production in 2007. A total of seven wells have been drilled, including exploration and appraisal wells, in the different fault blocks.
- *J3C (4 per cent.):* The J3C field was discovered in 1995. The field was developed by recompleting the discovery well, Well J6-A5. The well was shut-in from late August 2025 to end of April 2026 due to a mechanical failure on the J6A platform.
- *Clipper South (25 per cent.):* Clipper South is a gas field operated by Ineos Energy and located in blocks 48/19 and 48/20 in the Southern North Sea, approximately 100 km east of the Lincolnshire coast. Production is exported via the Shell-operated Clipper complex to the Bacton Terminal. A total of four development wells have been drilled, all online at 30 June 2026. Clipper South is a relatively young asset with significant remaining reserves, ensuring its continued contribution to the region's gas supply. There are multiple identified future drilling

opportunities on the block and in adjacent areas that have the potential to extend the production life of the field significantly.

- *Galleon (8.4 per cent.):* Galleon is located in blocks 48/14a, 48/15a, 48/19a and 48/20 in the Southern North Sea, east of Clipper and west of Audrey in the Sole Pit Area, around 65 kilometres from the coast of East Anglia. The field consists of 10 producing wells, delivering approximately 300 boepd net to Spirit Energy in HY 2026. Galleon is operated by Shell with the Shell/ExxonMobil JV having an 83.2 per cent. stake.
- *Eris (54 per cent.):* Eris is a single-well subsea tieback located approximately 34 kilometres east of the Easington Gas Terminal in the Southern North Sea. Eris sits in block 47/8c-4. It is set to cease production in 2026/2027, following which Serica, will undertake planned decommissioning work, with the costs retained by Spirit Energy (up to an agreed cap) under the terms of the Spirit Energy Portfolio Acquisition.
- *Ceres (90 per cent.):* Ceres is a single-well subsea tieback located approximately 44 kilometres east of the Easington Gas Terminal in the Southern North Sea in block 47/9c-11. It is set to cease production in 2026/2027, following which Serica, will undertake planned decommissioning work, with the costs retained by Spirit Energy under the terms of the Spirit Energy Portfolio Acquisition.

Following completion of the Spirit Energy Portfolio Acquisition, the Group also owns a 1.8 per cent. working interest in the Northern Offshore Gas Transport (NOGAT) pipeline system, which transports natural gas from Denmark and Dutch fields to a landing point at Den Helder in the Netherlands. The pipeline is owned by an incorporated joint venture (NOGAT B.V.) owned jointly by Eni (15 per cent., operator), EBN (45 per cent.), PGGM (38.2 per cent.) and Serica (1.8 per cent.) who receive tariff income from third party users of NOGAT.

6.6 Other Producing Fields

Production at Serica's other producing fields averaged 4,600 boepd in HY 2026 and 5,300 boepd in FY 2025.

- *Erskine (18 per cent.):* Serica holds an 18 per cent. non-operating interest in the Erskine field, which is located in the UK Central North Sea. The field, operated by Ithaca Energy plc, is a High Pressure High Temperature (HPHT) gas condensate field and was originally discovered in 1981. The production facilities comprise a normally unmanned platform located at Erskine with production handled and controlled from the Harbour-operated Lomond platform, 30 kilometres to the north. Gas and liquids produced from Erskine are transported to the Lomond platform where the fluids are processed. A late life compression project to extend the life of the Erskine field is planned to be carried out in 2027.
- *Columbus (75 per cent.):* Serica is the operator of Columbus and holds a 75 per cent. interest in the asset while Harbour Energy WPUK holds 25 per cent. The Columbus field is located in the UK Central North Sea and produces from a gas-condensate reservoir in the Forties Sandstone Formation. The development consists of a single horizontal well which runs along the central axis of the reservoir, drilled in the spring of 2021. Production commenced in November 2021.
- *Orlando (100 per cent.):* Serica holds a 100 per cent. operated interest in the Orlando Field. The Orlando Field is located in licence P1606 (block 3/3b), approximately 11 km east of the Ninian Field. The Orlando field development consists of a subsea tie-back of the single production well to the CNR International-operated Ninian Central Platform. Production halted in May 2026 due to a failure of the Electrical Submersible Pump. Given the proximity to the scheduled closure of the Ninian platform in 2027, it has been determined that the requisite remedial activity would not be cost effective. As such, there will be no further production from the field. Serica will be progressing to prepare for decommissioning and the plugging and abandonment of the well in due course.
- *Catcher (10 per cent.):* The Catcher field is located in the Central North Sea around 170 kilometre southeast of Aberdeen and operated by Harbour Energy. 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.
- *Golden Eagle Area Development (GEAD) (5.2 per cent.):* The GEAD consists of the Golden Eagle, Peregrine and Solitaire oil fields, which lie within Licence P300 (block 14/26a, sub-area

rest of block) and Licence P928 (block 20/01a, sub-area North) in the UK Central North Sea. CNOOC is the operator.

7. Current trading

The Company issued a trading and operations update on 19 October 2026 in respect of the first nine months of 2026. A summary of production at the Group's producing assets by hub (net to Serica) is set out below:

Asset	Q1 2026 (boepd)	Q2 2026 (boepd)	Q3 2026 (boepd)	Average (boepd)
Bruce Hub	17,700	18,400	8,300	14,800
Triton Hub	11,100	20,300	4,600	12,000
West of Shetland	6,200	6,800	4,500	5,800
Other Producing Assets	4,200	4,700	4,700	4,500
Total	39,200	50,200	22,100	37,100

Production of 37,100 boepd in the first nine months of 2026 represents an increase of 44 per cent from the 25,700 boepd in the prior year period. Q3 2026 production of 22,000 boepd is broadly in line with expectations, as the period includes planned annual maintenance at the Bruce and Triton Hubs. The Bruce Hub resumed production on 12 September 2026, with the Hub's production currently at around rates of 20,000 boepd (net to Serica). As noted in the trading update, annual maintenance at the Triton FPSO began on 27 July 2026, and the operator is currently expecting production to resume around the end of November 2026.

Taking into account the benefits of the Group's enlarged portfolio, including the addition of the Southern North Sea gas portfolio recently acquired from Spirit Energy, the Company maintains the expectation of reaching production rates of around 65,000 boepd once production resumes from the Triton FPSO.

The Group's revenue in the first nine months of 2026 was \$905 million, more than double the revenue in the first nine months of 2025 of \$439 million. The Company also reported capital expenditure of \$113 million in the first nine months of 2026, in line with guidance. The Company held cash of \$227 million as at 30 September 2026 (30 June 2026: \$326 million).

Work is stepping up on the delivery of Serica's organic growth plans. Serica is finalising a contract for a rig to execute a multi-well drilling campaign targeting high-return, near-field opportunities across the Group's portfolio. The Company believes that the opportunities targeted by the operated drilling campaign alone have the potential to add up to 30,000 boepd of incremental production to Serica, helping to sustain portfolio production of 50,000 boepd into the next decade.

Plans to drill Skerryvore on the existing P2400 licence, with a separately contracted rig, are also progressing. Negotiations relating to commercial terms under which the Tornado gas field would be processed within the Shetland Gas Plant are progressing. Together with the potential for further development work West of Shetland, securing production from Tornado would align with Serica's strategy to maximise utilisation and longevity of the Shetland Gas Plant. Further, in the non-operated portfolio, Serica has also given partner consent for two further wells as part of the ongoing successful infill drilling campaign at Cygnus, along with additional infill wells at Clipper South and Catcher fields.

Following the extension of the annual maintenance at Triton, Serica expects production for 2026 to average just below 40,000 boepd. All other guidance remains in line with previously stated ranges.

See also the section of this document entitled "*Risk Factors*" and paragraph 2 (*Information regarding forward-looking statements*) of the section of this document entitled "*Important Notices*" for a discussion of certain of the factors that could affect the Group's future performance and results of operations.

8. Dividend policy

Serica's capital allocation framework prioritises maintaining balance sheet strength, funding high-return organic growth, pursuing value-accretive M&A, and delivering sustainable shareholder distributions.

As announced by the Company on 2 June 2026, the Board has adopted a dividend policy designed to deliver attractive and sustainable shareholder returns while preserving flexibility to fund value-accretive

organic growth and M&A. For FY 2026 and annual dividends thereafter, Serica will target shareholder distributions of 15 to 30 per cent. of post-tax CFFO. This range is consistent with the level of Serica's historic shareholder distributions and is expected to support a continuation of the current 16 pence per share aggregate annual dividend, with potential for additional shareholder returns depending on financial performance.

On 6 August 2026, the Company announced an interim dividend of 6 pence per Ordinary Share in respect of the six months ended 30 June 2026. The interim dividend is payable on 19 November 2026 to shareholders on the Company's register on 23 October 2026.

In respect of the Company's financial year ended 31 December 2025, the Company declared and paid a total dividend of 16 pence per Ordinary Share. A final dividend for FY 2025 of 10 pence per Ordinary Share was paid on 24 July 2026, and an interim dividend for HY 2025 of 6 pence per Ordinary Share was paid on 20 November 2025. The new dividend policy announced on 2 June 2026 did not apply in respect of dividends declared in respect of FY 2025.

9. Arrangements relating to the Rhum field

Serica Energy (UK) Limited ("**Serica UK**"), a wholly-owned subsidiary of Serica, holds a 50 per cent. interest in the Rhum gas field and is the operator of the field. The remaining non-operated 50 per cent. in the licence has been owned by Iranian Oil Company (U.K.) Limited since 1972. Prior to a restructuring of the ownership structure of IOC (the "**IOC Restructure**"), IOC was a subsidiary of Naftiran Intertrade Co. (NICO) Limited. NICO is a subsidiary of National Iranian Oil Company, the state oil company of Iran. The IOC Restructure had the effect of separating IOC and its interest in the Rhum field from any Iranian ownership, management or economic interest until such time as US sanctions on IOC's previous Iranian owners are lifted.

In May 2018, the US announced its withdrawal from the 2015 JCPOA and the tightening of US sanctions on Iran. IOC, NICO, and NIOC are on OFAC's Specially Designated Nationals and Blocked Persons list, which means that the maintenance of Rhum field operations requires (1) an OFAC License from OFAC to protect US persons and non-US entities owned or controlled by US persons from exposure to US primary sanctions; and (2) a secondary sanctions assurance from OFAC to protect non-US persons from exposure to US secondary sanctions should they provide goods, services or support to Rhum field operations.

OFAC has issued multiple licences in respect of Rhum without interruption since 2013 including for the entire period in which Serica has owned its interest in, and operated, the field (since late 2018). Serica currently operates under an OFAC License and secondary sanctions assurance renewed in February 2025 and valid until the end of February 2027.

The IOC Restructure is centred on a Jersey non-charitable purpose trust (the "**Purpose Trust**") set up to hold shares in IOC. The Purpose Trust exists for the sole purpose of holding 100 per cent. of the shares of IOC and maintenance of production and economic recovery from the Rhum field. IOC, within the Purpose Trust, continues to hold its 50 per cent. interest in the Rhum field, but does so without any connection to its previous Iranian owners. The Purpose Trust has no beneficiaries during the purpose period and will exist in perpetuity unless there is a termination event under the terms of the trust deed. The trust deed provides that if US sanctions on Iran are relaxed and IOC, NICO and NIOC are no longer subject to US sanctions, the Purpose Trust will cease to be a purpose trust and become a bare trust, the beneficiary of which will be NICO (or NIOC's nominee). The trust deed contains restrictions which prevent the trustee from distributing the assets of the Purpose Trust including the shares in IOC or Rhum Management Company Limited ("**RMC**").

All the decision-making powers in relation to IOC's interest in Rhum are delegated to RMC, an English private limited liability company, under a management agreement between IOC and RMC. RMC is also wholly owned by the Purpose Trust and has a board of directors, comprising professional oil and gas managers and representatives of the trustee of the Purpose Trust. These persons manage IOC's non-operated interest in Rhum field such that RMC acts effectively as Serica's joint venture partner in the Rhum field. This arrangement separates IOC from any involvement in operations or management of the Rhum field. All cash flows from the IOC interest in Rhum since the IOC Restructure are accumulated in a UK bank account held by RMC.

Please refer also to the section of this document entitled "*Risk Factors*" for a summary of certain risks relating to the Group's operation of the Rhum field.

PART 2

DIRECTORS AND CORPORATE GOVERNANCE

1. Board of Directors

1.1 Directors

The following table lists the names, positions and independence status of the Directors of the Company:

Name	Position	Independence Status
David Michael Latin	Chair	Independent
Christopher Martin Cox	Chief Executive Officer	Non-independent
Martin Francis David Copeland	Chief Financial Officer	Non-independent
Katherine Jane Coppinger	Senior Independent Director	Independent
Michiel Soeting	Independent Non-Executive Director	Independent
Robert Stephen Lawson	Non-Executive Director	Non-independent
Guillaume Jean Roger Vermersch	Non-Executive Director	Non-independent
Kaat Juliana Van Hecke	Independent Non-Executive Director	Independent
Sian Lloyd Rees	Independent Non-Executive Director	Independent

Summary biographical details of each of the Directors are set out below. The business address of each of the Directors is the Company's registered address at 4th Floor, 72 Welbeck Street, London, England, W1G 0AY.

David Latin, *Non-Executive Chair*

Mr Latin joined the Board on 7 December 2021, initially serving as an Independent Non-Executive Director. He was later appointed Non-Executive Chair in June 2023, succeeding Antony Craven Walker upon his retirement. Additionally, Mr Latin temporarily took on the role of Interim CEO from 24 April 2024, to 1 July 2024, until the appointment of Chris Cox as permanent CEO. Mr Latin has over 30 years' experience in Upstream Exploration and Production. He worked at BP for 18 years, where he was responsible for the BKR assets for 6 years and then held a number of senior VP and global/regional business roles. He was later OMV Group Senior Vice President for E&P in NW Europe, Africa and Australasia during which time he was responsible for building significant businesses in the UK (sold to Siccra Point Energy) and in Norway. Mr Latin was awarded a PhD in Geology and Geophysics by Edinburgh University, is a Fellow of the Geological Society and a Chartered Director of the Institute of Directors. He serves as the chair of the Nominations Committee of the Company.

Chris Cox, *Chief Executive Officer*

Mr Cox joined the Board on 1 July 2024. Mr Cox has over forty years' experience in oil and gas in a wide range of roles with Majors and Independents. For the last two decades he has been leading complex multi-asset and multi-country businesses including as CEO of Spirit Energy, Interim CEO at Capricorn Energy and Chairman of Kellas Midstream. Mr Cox has experience as a non-executive director of both private equity and publicly listed companies, most recently with Nostrum Oil and Gas. Mr Cox holds a BSc in Petroleum Engineering from Imperial College, London. He is a member of the HSE Committee and the Reserves Committee of the Company.

Martin Copeland, *Chief Financial Officer*

Mr Copeland joined the Board on 5 February 2024. Mr Copeland was previously a Principal at energy advisory firm Kirk Lovegrove & Co. Ltd and has over 30 years' experience in oil and gas financing and advisory roles across a number of investment banks prior to joining Serica. Mr Copeland has led the Serica finance team including the M&A and Investor Relations activities of the Group. Prior to joining Serica, his North Sea-related transaction experience includes advising Premier Oil on their reverse takeover by Chrysaor to create Harbour Energy, advising JX Nippon on the sale of their UK North Sea business to Neo Energy and advising Tailwind Energy on their sale to the Company in 2022. He is a member of the Sustainability Committee of the Company.

Kate Coppinger, *Senior Independent Non-Executive Director*

Ms Coppinger joined the Board on 22 April 2020. Ms Coppinger has over 20 years' investment banking experience. Ms Coppinger's career includes roles at Canadian Imperial Bank of Commerce, Harrison Lovegrove and Managing Director at Standard Chartered in the Oil and Gas team responsible for origination and execution of transactions for European clients. Her global M&A transaction experience spans Asia through to South America with particular emphasis on the North Sea. She serves as the chair of the Remuneration Committee of the Company and is also a member of the Audit and Risk Committee and the Nominations Committee.

Michiel Soeting, *Independent Non-Executive Director*

Mr Soeting joined the Board on 1 February 2023. Mr Soeting is a chartered accountant, qualified in both the Netherlands and the United Kingdom, he has extensive financial expertise, strong governance, risk management and regulatory compliance experience. Mr Soeting has over 30 years' experience in the audit and financial service sector, he was the former global lead partner and global head of energy & natural resources at KPMG. Mr Soeting serves as the chair of the Audit and Risk Committee, and is a member of the Remuneration Committee and Reserves Committee.

Robert Lawson, *Non-Executive Director*

Mr Lawson joined the Board on 23 March 2023. Mr Lawson was nominated to the Board by, and represents, Mercuria pursuant to the terms of a relationship agreement entered into as part of the Tailwind Acquisition. Mr Lawson spent a large part of his career with BP in various roles including Commercial Vice President for BP's Refining and Marketing Segment then becoming the Global Head of Mergers and Acquisitions. He was Executive Vice President and a member of the Board at Mercuria Energy group from the end of 2022 to 2025 and left Mercuria to take up the role of Chief Executive & Secretary at Marylebone Cricket Club. Mr Lawson is a member of the Nominations Committee and the Sustainability Committee of the Company.

Guillaume Vermersch, *Non-Executive Director*

Mr Vermersch joined the Board on 23 March 2023. Mr Vermersch was nominated to the Board by, and represents, Mercuria pursuant to the terms of a relationship agreement entered into as part of the Tailwind Acquisition. Mr Vermersch started his career with Arthur Andersen in Paris. His career includes roles at ING/BBL Bank and CIB in Geneva and Paris and as head of the Credit and Finance Risk department of Sempra Oil Trading for Europe and Asia where he was responsible for defining, implementing and monitoring the full scope of the Sempra Energy credit and financial strategies, from trading business requirements to banking, finance and risk management responsibilities to support the oil and energy division's expansion. He is the group chief financial officer and a group board member of Mercuria Energy group.

Kaat Van Hecke, *Independent Non-Executive Director*

Ms Van Hecke joined the Board on 17 July 2023. Ms Van Hecke has over 25 years' experience in the petrochemicals and oil and gas business. She has held positions with ExxonMobil, Shell, OMV and Nostrum in Belgium, the Netherlands, Nigeria, Russia, Austria and Kazakhstan. Ms Van Hecke was previously MD and Senior Vice President OMV Austria E&P and interim CEO at Nostrum Oil and Gas, she is also a non-executive director of Axxela Ltd. She serves as the chair of the HSE Committee and Reserves Committee of the Company, and is a member of the Audit and Risk Committee of the Company.

Sian Lloyd Rees, *Independent Non-Executive Director*

Ms Rees joined the Board on 17 July 2023. Ms Rees' career includes roles at Halliburton Corporation, Oracle Corporation and Aker Group and most recently as UK MD of Aker Horizons and Mainstream Renewable Power, responsible for growing a renewable energy portfolio in offshore wind and hydrogen. Ms Rees has over 30 years' experience in the Oil and Gas, IT and Renewable Energy industries, she is also a non-executive director and co-chair of Offshore Energies UK (OEUK), non-executive director for the Net Zero Technology Centre and non-executive director of Port of Aberdeen. Ms Rees serves as chair of the Sustainability Committee, and is a member of the Remuneration Committee and the HSE Committee of the Company.

1.2 Directorships and partnerships of Directors

Set out below are details of those companies and partnerships (other than members of the Group) of which the Directors have been a member of the administrative, management or supervisory bodies or partner in the five years prior to the date of this document. The table below does not set out all the subsidiaries of an entity which the Director is also a member of the administrative, management or supervisory bodies.

Name	Current directorship/ partnership	Former directorship/ partnership
David Michael Latin	Aker BP First Alpha Services Ltd	Talaria Technology Limited
Christopher Martin Cox	The UK Offshore Energies Association Limited	Capricorn Energy plc Curium Resources Limited (<i>dissolved</i>) ^{(2), (3)} Curium Energy Consultants Limited (<i>dissolved</i>) ^{(1), (3)} Nostrum Oil & Gas plc Oxomo Tequila Ltd (<i>dissolved</i>) ^{(1), (4)} Spirit Energy Limited
Martin Francis David Copeland	Chace Freehold Company Limited	Ashford Community Fibre Optic C.I.C. (<i>dissolved</i>) ^{(1), (5)}
Katherine Jane Coppinger	The Barnes Fund Trustee Limited M.P. Evans Group plc Star Energy Group plc 86 Castelnau Freehold Company Limited	PI AgSciences Limited
Michiel Soeting	Veon Ltd Kyivstar Group Limited	None
Robert Stephen Lawson	London Spirit (The Hundred) Limited Marylebone Cricket Club Foundation MCC Overseas Limited	British American Football Association
Guillaume Jean Roger Vermersch	Mercuria Energy Group Holding SA	Amromco Holding SA Phoenix Global Resources Limited
Kaat Juliana Van Hecke	Axxela Limited Axxela Funding 1 Plc Transit Gas Nigeria Limited	Trinity Exploration & Production Limited Nostrum Oil & Gas plc
Sian Lloyd Rees	Awenbusiness Solutions Ltd Energy Transition Zone Ltd Ignitis Grupe Moreld ASA Net Zero Technology Centre Limited Port of Aberdeen	Aker Offshore Partner Ltd Aker Offshore Wind Ltd ⁽¹⁾ Aker Engineering Malaysia Ltd Aker Engineering & Technology Ltd Aker Solutions Holding Ltd Arven South Holdings Limited Diatom Energy Limited ⁽⁴⁾ Dubh Artach Holdings Limited Onesubsea International IP Ltd (<i>previously known as Aker Solutions IP Ltd</i>) Pennate Ltd ^{(1), (6)}

Name	Current directorship/ partnership	Former directorship/ partnership
		Ricardo Limited UK Mainstream Renewable Power Limited The UK Offshore Energies Association Limited

Notes:

- (1) Dissolved via a voluntary strike-off.
- (2) Dissolved by way of a solvent members' voluntary winding-up process.
- (3) Christopher Cox was a director of Curium Energy Consultants Limited (dissolved on 24 September 2024) when it made an application to be voluntarily struck-off, a director of Curium Resources Ltd (*in liquidation*) in the 12 months preceding the passing of a shareholder's resolution to voluntarily wind-up the company, and a director of Oxomo Tequila Ltd (dissolved on 11 July 2023) when it made an application to be voluntarily struck-off.
- (4) Dissolved by way of compulsory strike-off.
- (5) Martin Copeland was a director of Ashford Community Fibre Optic C.I.C. (dissolved on 16 January 2024) when it made an application to be voluntarily struck-off.
- (6) Sian Lloyd Rees was a director of Pennate Ltd (dissolved on 19 August 2025) when it made an application to be voluntarily struck-off.

1.3 Directors' interests in the Company

Each of the Directors' interests in the share capital of the Company as at the Latest Practicable Date is as follows:

Name	Number of Ordinary Shares	Percentage of issued share capital (%)
David Michael Latin	218,567	0.056
Christopher Martin Cox	496,034	0.126
Martin Francis David Copeland	107,500	0.027
Katherine Jane Coppinger	N/A	N/A
Michiel Soeting	42,300	0.011
Robert Stephen Lawson	N/A	N/A
Guillaume Jean Roger Vermersch	N/A	N/A
Kaat Juliana Van Hecke	N/A	N/A
Sian Lloyd Rees	2,114	0.001

As at the Latest Practicable Date, each of the following Directors held awards granted under the Serica Energy plc 2017 Long Term Incentive Plan:

Name	Number of Awards	Date of grant	Vesting Date	Expiry Date
Christopher Martin Cox	523,255	16 April 2026	16 April 2029	16 April 2036
	624,161	28 May 2025	28 May 2028	28 May 2035
	494,233	24 July 2024	24 July 2027	24 July 2034
Martin Francis David Copeland	264,534	16 April 2026	16 April 2029	16 April 2036
	348,154	28 May 2025	28 May 2028	28 May 2035
	274,574	24 July 2024	24 July 2027	24 July 2034

1.4 Conflict of interest of Directors

Save as disclosed above, none of the Directors have any actual or potential conflicts of interest between any duties they owe to the Company and any private interests or other duties they may also have.

1.5 Director confirmations

- (a) Save as set out above in paragraph 1.3 of this Part 2 (*Directors and Corporate Governance*), as at the date of this document, none of the Directors has:
- (i) had any convictions in relation to fraudulent offences at any time in the five years prior to the date of this document;
 - (ii) any unspent convictions in relation to indictable offences;
 - (iii) been a director of a company, a member of an administrative, management or supervisory body or a senior manager of a company which has entered into any bankruptcy, receivership, liquidation proceedings or which has been put into administration at any time in the five years prior to the date of this document; or
 - (iv) been subject to any official public incrimination and/or sanctions by statutory or regulatory authorities (including taxation authorities and designated professional bodies) or has been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of an issuer or from acting in the management or conduct of the affairs of any issuer at any time in the five years prior to the date of this document.
- (b) Pursuant to the terms of the existing relationship agreement, Mercuria is entitled to nominate two non-executive directors to the Board, for as long as it and its affiliates hold 20 per cent. or more of the Company's Ordinary Shares. Mercuria is entitled to the same rights under the Amended Relationship Agreement. A summary of the Amended Relationship Agreement is set out in paragraph 9.4 of Part 7 (*Additional Information*) of this document. Each of Robert Lawson and Guillaume Vermersch is a representative of Mercuria, and was nominated to the Board for appointment by Mercuria.
- Save as disclosed above, no Director was selected to act in such capacity pursuant to any arrangement or understanding with any shareholder, consumer, supplier or any other person having a business connection with the Group.
- (c) There are no family relationships between any of the Directors.

2. Corporate governance

Serica's Board fully endorses the importance of good corporate governance and is focused and committed to delivering high standards of corporate governance and robust risk management. The Company currently applies the Quoted Companies Alliance Corporate Governance Code 2023. The Board has resolved to adopt and report against the UK Corporate Governance Code with effect from Admission. The Company intends to comply in full with the UK Corporate Governance Code as soon as practicable following Admission and thereafter on an ongoing basis.

2.1 Board Committees

The Board has the following Committees: (i) Audit and Risk Committee; (ii) Nominations Committee; (iii) Remuneration Committee; (iv) Health, Safety and Environment Committee; (v) Sustainability Committee; and (vi) Reserves Committee (which is a sub-committee of the Audit and Risk Committee), each with formally delegated duties and responsibilities and written terms of reference which have been approved by the Board and are reviewed regularly. If the need should arise, the Board may set up additional committees as appropriate.

(a) *Audit and Risk Committee*

The Audit and Risk Committee has been appointed by the Board to provide oversight of, among other matters, the integrity of the Company's financial statements and other financial reporting, and the appointment and independence and remuneration of the auditors. The Audit and Risk Committee also, among other matters, oversees the Company's risk management framework and internal control systems to ensure they are effective, proportionate and aligned with the Company's strategic objectives and risk appetite, and to assess the procedures in place for detecting fraud and preventing bribery and corruption. The Audit and Risk Committee has set up the Reserves Committee as a sub-committee with its own terms of reference. The Audit and Risk Committee meets formally at least three times a year. At least one meeting per year shall not have any members of the executive management present. The Audit and Risk Committee shall consist of not fewer than three directors, all of whom shall be independent non-executive directors. The chair of the Board shall not be a member of the Audit and Risk Committee.

The Audit and Risk Committee is chaired by Michiel Soeting, with Kate Coppinger and Kaat Van Hecke as members. Guillaume Vermersch is not a member of the Audit and Risk Committee, but attends meetings of the committee in an observer capacity.

(b) Nominations Committee

The Nominations Committee has been appointed by the Board, to assist the Board in fulfilling its responsibilities regarding Board appointments and succession planning, and ensuring the Board works effectively. Duties of the Nominations Committee include assessing the structure, size and composition of the Board, including the skills, knowledge, independence, experience, length of service, range of perspectives and diversity of the Board, ensuring plans are in place for orderly succession to Board and senior management positions and considering the results of the annual review of performance of the Board. The Nominations Committee is also responsible for implementing and overseeing the Board's policy and initiatives on diversity and inclusion. The Nominations Committee meets at least twice a year, including one meeting without executive management present. The Nominations Committee shall comprise at least three directors, the majority of whom shall be independent non-executive directors.

The Nominations Committee is chaired by David Latin, with Kate Coppinger and Robert Lawson as members.

(c) Remuneration Committee

The Remuneration Committee has been appointed by the Board to assist in fulfilling the Board's responsibilities relating to the Company's remuneration and benefits policies and practices, including on an annual basis (or more frequently if considered appropriate) the remuneration of executive directors and the chair of the Board. It also reviews periodically, not less than once every two years, the Company's policy and practice regarding remuneration and employment benefits of all employees. The Remuneration Committee meets at least three times a year, including one meeting without executive management present. The Remuneration Committee shall consist of not fewer than three directors, all of whom shall be independent non-executive directors.

The Remuneration Committee is chaired by Kate Coppinger, with Michiel Soeting and Sian Lloyd Rees as members.

(d) Health, Safety and Environment Committee

The Health, Safety and Environment Committee has been appointed by the Board to assist the Board in fulfilling its responsibility to ensure that management of the Company has designed and implemented effective risk programmes, controls and reporting systems in respect of health, safety and environment ("HSE") matters. The Health, Safety and Environment Committee shall, among other matters, ensure that the executive leadership team is proactively engaged in HSE and ESG management, and is properly resourced with clear accountabilities, and review and report to the Board on the effectiveness of the Company's HSE and ESG programmes, and ensures that the standards and procedures adopted for the Company's operations meets the requirements of the laws and guidelines of local jurisdictions. The Health, Safety and Environment Committee meets at least three times a year, including one meeting without executive management present. The Health, Safety and Environment Committee shall consist of not fewer than three directors, the majority of whom shall be independent non-executive directors.

The Health, Safety and Environment Committee is chaired by Kaat Van Hecke, with Sian Lloyd Rees and Chris Cox as members.

(e) Sustainability Committee

The Sustainability Committee has been appointed by the Board to review and provide oversight of the Company's strategies, goals, policies, procedures, performance and disclosures related to sustainability and environmental, social and governance matters, including responsibility for monitoring and reviewing sustainability and climate-related risks and opportunities. The duties of the Sustainability Committee include, among other matters, monitoring the Company's environmental performance, steering Serica's energy transition strategy, providing assurance that emissions reduction projects are being delivered, ensuring transparency in ESG reporting 'beyond compliance' and reviewing investment options in the energy strategy sector. The Sustainability Committee meets at least three times a year, including one meeting without executive management present. The Sustainability Committee shall consist of not fewer than three directors, the majority of whom shall be independent non-executive directors.

The Sustainability Committee is chaired by Sian Lloyd Rees, with Robert Lawson and Martin Copeland as members.

(f) *Reserves Committee*

The Reserves Committee is a sub-committee of the Audit and Risk Committee, and assists the Board in reviewing the reports of the independent reserves auditors to ensure the Company's compliance with relevant legal and regulatory requirements. The Reserves Committee also evaluates the effectiveness of the Company's technical reserves processes and standards, and reviews and recommends to the Board for approval the content and filing of the Company's annual statement of reserves data and other oil and gas information. The Reserves Committee meets at least three times a year, including one meeting without executive management present. The Reserves Committee shall consist of not fewer than three directors, the majority of whom shall be independent non-executive directors.

The Reserves Committee is chaired by Kaat Van Hecke, with Michiel Soeting and Chris Cox as members.

PART 3

SELECTED FINANCIAL INFORMATION

Section A: Selected Historical Financial Information of the Group

The tables below set out the Group's selected financial information for the periods indicated, as reported in accordance with UK IAS. The selected financial information for the Group as of and for the year ended 31 December 2025 has been extracted without material adjustment from the audited consolidated financial statements of the Group for the year ended 31 December 2025. The selected financial information for the Group as of and for the six months ended 30 June 2026 has been extracted without material adjustment from the unaudited condensed consolidated financial statements of the Group for the six months ended 30 June 2026.

The audited consolidated financial statements of the Group for the year ended 31 December 2025 and the unaudited condensed consolidated financial statements of the Group for the six months ended 30 June 2026 have been incorporated into this document by reference as set out in Part 8 (*Documents Incorporated by Reference*) of this document.

Recipients of this document should read this document in its entirety, including the information incorporated herein by reference, and should not rely solely on the financial information set out in this Part 3 (*Selected Financial Information*).

1. Group Income Statement

	Six months ended 30 June 2026	Year ended 31 December 2025
	<i>(Unaudited)</i> \$'000	<i>(Audited)</i> \$'000
Continuing operations		
Sales revenue	677,099	601,429
Cost of sales	(405,194)	(536,689)
Gross profit	271,905	64,740
Unrealised hedging (losses)/gains	(110,843)	67,371
Realised hedging (losses)/gains	(88,600)	7,795
Contract revenue – other	—	5,408
Exploration expense	—	(1,100)
E&E asset write-offs	—	(147)
Impairment of producing assets	(5,820)	—
Administrative expenses	(14,619)	(23,075)
Foreign exchange (loss)/gain	(1,526)	38
Transaction costs	(3,048)	(5,533)
Share-based payments	(1,648)	(3,523)
Expense of goodwill	(95,582)	—
Operating (loss)/profit	(49,781)	111,974
Change in fair value of financial liabilities	(4,508)	(2,471)
Finance revenue	1,455	6,102
Finance costs	(22,771)	(35,262)
(Loss)/profit before taxation	(75,605)	80,343
Taxation credit/(charge) for the period	81,739	(132,165)
Profit/(loss) after taxation and profit/ (loss) for the period	6,134	(51,822)
Earnings/(loss) per ordinary share		
Basic EPS on profit/(loss) for the year (\$)	0.02	(0.13)
Diluted EPS on profit/(loss) for the year (\$)	0.02	(0.13)

2. Group Balance Sheet

	As at 30 June 2026	As at 31 December 2025
	<i>(Unaudited)</i> \$'000	<i>(Audited)</i> \$'000
Non-current assets		
Exploration & evaluation assets	64,858	43,283
Property, plant and equipment	1,145,707	1,155,716
Goodwill	50,448	56,497
Derivative financial assets	—	5,667
Deferred tax asset	106,557	—
	<u>1,367,570</u>	<u>1,261,163</u>
Current assets		
Inventories	22,124	31,423
Trade and other receivables	232,095	170,993
Corporate tax receivable	—	13,026
Derivative financial assets	—	24,260
Restricted cash	1,460	12,060
Cash and cash equivalents	324,451	18,840
	<u>580,130</u>	<u>270,602</u>
TOTAL ASSETS	<u>1,947,700</u>	<u>1,531,765</u>
Current liabilities		
Trade and other payables	222,124	211,646
Derivative financial liability	50,581	—
Corporate tax payable	54,923	—
Financial liabilities	5,164	4,140
Lease liabilities	3,683	2,308
Dividends payable	51,897	—
Provisions	19,109	18,712
Non-current liabilities		
Derivative financial liabilities	30,048	—
Financial liabilities	100,041	89,756
Deferred tax liability	—	77,132
Lease liabilities	7,388	3,415
Provisions	496,718	233,594
Interest bearing loans	284,139	221,488
TOTAL LIABILITIES	<u>1,325,815</u>	<u>862,191</u>
NET ASSETS	<u>621,885</u>	<u>669,574</u>
Share capital	245,715	245,715
Merger reserve	286,590	286,590
Other reserve	42,711	41,063
Treasury/own shares	(3,397)	(6,678)
Accumulated funds	52,043	101,087
Currency translation reserve	(1,777)	1,797
TOTAL EQUITY	<u>621,885</u>	<u>669,574</u>

3. Group Cash Flow Statement

	Six months ended 30 June 2026	Year ended 31 December 2025
	<i>(Unaudited)</i>	<i>(Audited)</i>
	\$'000	\$'000
Cash inflow from operations	270,493	179,946
Taxation received/(paid)	9,126	63,358
Decommissioning spend	(5,847)	(1,088)
Net cash inflow from operating activities	<u>273,772</u>	<u>242,216</u>
Investing activities:		
Interest received	1,455	5,486
Purchase of E&E assets	(1,370)	(6,467)
Purchase of property, plant and equipment	(79,427)	(242,567)
Acquisition of asset interests	(4,168)	(11,720)
Business combination, net cash received/ acquired	68,682	2,235
Net cash flow from investing activities	<u>(14,828)</u>	<u>(253,033)</u>
Financing activities:		
Payments of lease liabilities	(2,071)	(1,943)
Proceeds from share issues	—	178
Repayment of borrowings	(231,000)	(51,848)
Proceeds from borrowings – net	293,199	51,848
Dividends paid	—	(84,853)
Share buyback	—	(9,819)
Finance costs paid	(11,361)	(25,900)
Net cash flow from financing activities	<u>48,767</u>	<u>(122,337)</u>
Cash and cash equivalents		
Net increase/(decrease) in period	307,711	(133,154)
Effect of exchange rates on cash and cash equivalents	(2,100)	3,534
Amount at start of period	18,840	148,460
Amount at end of period	<u>324,451</u>	<u>18,840</u>

Section B: FY 2026 Post-Tax CFFO Guidance

On 2 June 2026, the Company published an announcement which included the following statement in relation to guidance for FY 2026: “*Serica expects post-tax CFFO in 2026 of \$470-520 million.*”

On 6 August 2026, the Company provided an update to its production guidance in its announcement of the Group’s results for the six months ended 30 June 2026, which included the following statement (the “**FY 2026 Post-Tax CFFO Guidance**”):

“Post-tax CFFO guidance is impacted by the later completion of the Spirit Energy acquisition and is therefore revised to \$450-475 million, consistent with current forward curve pricing”

The Company confirmed the FY 2026 Post-Tax CFFO Guidance in its trading and operations update on 19 October 2026 (the “**Q3 2026 Trading Update**”).

1. Directors’ Confirmation

The statements above relating to FY 2026 post-tax CFFO guidance constitute profit forecasts under the PRM.

The Directors confirm that only the FY 2026 Post-Tax CFFO Guidance continues to be valid at the date of this document. As noted above and in the 2026 Interim Results, the Directors revised their guidance for FY 2026 post-tax CFFO as a result of the delay in completion of the Spirit Energy Portfolio Acquisition. Accordingly, the Directors confirm the FY 2026 post-tax CFFO guidance provided in the announcement dated 2 June 2026 is no longer valid.

The FY 2026 Post-Tax CFFO Guidance is not a representation of facts and should not be regarded as such by prospective investors. Rather, the FY 2026 Post-Tax CFFO Guidance is a statement about the forward-looking expectations of the Company with respect to the Group’s post-tax CFFO position for FY 2026.

2. Protected forward-looking statements

The statement “*Post-tax CFFO guidance is impacted by the later completion of the Spirit Energy acquisition and is therefore revised to \$450-475 million, consistent with current forward curve pricing*”, which is in underline and italic font in this Section B of Part 3 (*Selected Financial Information*) above, is a “protected forward-looking statement” for the purposes of PRM 8.

3. Basis of Preparation

The FY 2026 Post-Tax CFFO Guidance is based on the Group’s internal unaudited forecasts for financial year ending 31 December 2026. The FY 2026 Post-Tax CFFO Guidance has been compiled on the basis of the assumptions set out below and on a basis comparable with the Group’s results for the financial year ended 31 December 2025. The basis of the accounting policies used in the FY 2026 Post-Tax CFFO Guidance is consistent with the existing accounting policies of the Group.

4. Assumptions relating to the FY 2026 Post-Tax CFFO Guidance

Any forward-looking statements and profit forecasts, including the FY 2026 Post-Tax CFFO Guidance, are necessarily based on a number of assumptions and estimates about future events and significant business, operational, economic and competitive uncertainties and contingencies, many of which are beyond the Group’s control, and upon assumptions with respect to future business decisions that are subject to change.

The statements relating to the FY 2026 Post-Tax CFFO Guidance are based on assumptions made by the Company with respect to the Group’s cash inflow from operations and tax charges for FY 2026 as set out below.

Certain of the assumptions used in relation to the FY 2026 Post-Tax CFFO Guidance relate to factors which are beyond the control of the Company and the Directors or factors which can, to a limited extent only, be influenced by the Company and the Directors. Although the Directors believe that these assumptions are reasonable on the date as of which the FY 2026 Post-Tax CFFO Guidance has been prepared, they may subsequently prove to have been unjustified or incorrect. If any of these assumptions proves to have been unjustified or incorrect, the Group’s actual post-tax cash inflow from operations could deviate materially from the statement made in the 2026 Interim Results and the Q3 2026 Trading Update. Accordingly, prospective investors should treat this information with caution and should not place undue reliance on the FY 2026 Post-Tax CFFO Guidance.

The Directors have made the following assumptions in respect of the financial year ending 31 December 2026:

4.1 Assumptions within the Company's control or influence

- no material change to the existing strategy or operation of the Group's business and operations including, *inter alia*, the recommencing of production from the Triton Hub from around the end of November 2026;
- no adverse change to the Company's production guidance for the financial year ending 31 December 2026;
- no material asset acquisitions or disposals;
- no material change to the Group's production licences;
- no material change to the hedging profile currently assumed in the FY 2026 Post-Tax CFFO Guidance;
- no adverse change to the lifting schedule from the Triton Hub and payment from any liftings in FY 2026 being received during FY 2026; and
- no material change to the management or control of the Group.

4.2 Assumptions outside of the Company's control or influence

- no material change to existing prevailing macroeconomic, political, fiscal/inflationary, international trade or social conditions or stability during FY 2026 in the markets or regions in which the Group operates;
- no material change in legislation, taxation or regulatory requirements impacting the Group's operations, expenditure or its accounting policies;
- no material change in interest rates, exchange rates, bases of taxes or labour costs that would have a material impact on the Group;
- no material unplanned capital expenditure or unplanned operating expenditure affecting the Group;
- no material change to the range of oil, gas or NGL prices realised by the Group currently assumed in the FY 2026 Post-Tax CFFO Guidance;
- no material change to the level of the Group's oil and gas reserves and contingent resources, their quality or production volumes to those currently anticipated by the Company;
- no significant outages or downtime at the Group's assets or the infrastructure and/or transportation systems on which the Group relies, that would have a material impact on the Group;
- no material adverse change to the Group's business model or market environment before the end of FY 2026 (including in relation to customer demand or competitive environment);
- no extremes of weather that will have a material impact on the Group's operations and results; and
- no material adverse events or business disruptions that would have a significant impact on the Group, its customers or operations, such as global political events, natural disasters, disruptions to operations due to mechanical problems, accidents, system malfunctions or physical damage to assets and facilities.

PART 4

CAPITALISATION AND INDEBTEDNESS

The following tables show the Group's capitalisation and indebtedness as at 31 August 2026. Both the capitalisation and indebtedness information have been extracted without material adjustment from the accounting records for the period to 31 August 2026.

1. Capitalisation

The table below sets out the capitalisation of the Group as at 31 August 2026:

	Unaudited as at 31 August 2026
	<u>\$'000</u>
Total current debt (including current portion of long-term debt)	
Unguaranteed / unsecured	8,206
Total non-current debt (excluding current portion of long-term debt)	
Secured	30,000
Unguaranteed / unsecured	411,193
Shareholders' equity	
Share capital	39,357
Share premium	206,358
Other reserves ⁽¹⁾	330,754
Total capitalisation	<u><u>1,025,868</u></u>

Note:

(1) The figures disclosed above for other reserves include a merger reserve credit of \$286,590,000, other share reserves credit of \$43,367,000, a currency translation reserve credit of \$3,768,000, and treasury/own shares debit of \$2,971,000.

There has been no material change in the Group's capitalisation since 31 August 2026 to the date of this document.

2. Indebtedness

The following table sets out the indebtedness of the Group as at 31 August 2026:

	Unaudited as at 31 August 2026
	<u>\$'000</u>
Cash and cash equivalents	308,005
Liquidity	308,005
Current financial debt (including debt instruments, but excluding current portion of non-current financial debt) ⁽³⁾	(303)
Current portion of non-current financial debt ⁽¹⁾	(7,903)
Current financial indebtedness	<u>299,799</u>
Net current financial indebtedness	
Non-current financial debt (excluding current portion and debt instruments) ⁽¹⁾⁽²⁾	(111,193)
Debt instruments ⁽³⁾	(330,000)
Non-current financial indebtedness	<u>(441,193)</u>

Unaudited as
at 31 August
2026

Total financial indebtedness

(141,394)

Notes:

- (1) The figures disclosed above for financial debt include lease liabilities, comprising \$2,682,000 current lease liabilities and \$8,179,000 non-current lease liabilities.
- (2) The figures disclosed above for financial debt include contingent consideration of \$76,014,000 deferred consideration of \$5,221,000, and royalty payable of \$27,000,000 relating to past transactions.
- (3) The figures disclosed above for debt instruments include Nordic bonds, comprising \$303,000 current accrued interest and £300,000,000 non-current principal, and a non-current RBL facility outstanding of \$30,000,000.

There has been no material change in the Group's indebtedness since 31 August 2026 to the date of this document.

3. Indirect and Contingent Indebtedness

The Company's indirect and contingent indebtedness as at 31 August 2026, which is included in the statements of capitalisation and indebtedness above, is as follows.

Included in current financial debt:

- (a) **Parkmead E&P Contingent Consideration** – deferred consideration relating to the Parkmead acquisition of \$5.2 million (31 December 2025: \$8.9 million).

Included in non-current financial debt:

- (b) **BKR Contingent Consideration** – remaining deferred consideration projected to be paid under the BKR acquisition agreements of \$64.6 million (31 December 2025: \$60.2 million)
- (c) **GLA Contingent Consideration** – contingent consideration payable on the GLA acquisition of \$11.4 million (31 December 2025: \$nil).
- (d) **Royalty Liability** – Royalty liabilities of \$27.0 million (31 December 2025: \$24.8 million) for amounts payable to third parties under the terms of Triton asset acquisitions.

PART 5

HISTORICAL FINANCIAL INFORMATION

The following financial information relating to the Group is incorporated by reference into this document as described in Part 8 (*Documents Incorporated by Reference*) of this document:

- the audited consolidated financial statements of the Group as at and for the year ended 31 December 2025, prepared in accordance with UK IAS, together with the audit report thereon and notes thereto, as contained in the 2025 Annual Report; and
- the unaudited condensed consolidated financial statements of the Group as at and for the six months ended 30 June 2026, prepared in accordance with International Accounting Standard 34 '*Interim Financial Reporting*', together with the notes thereto, as contained in the 2026 Interim Results.

The independent auditor's report in respect of the financial information for the financial year ended 31 December 2025 was unqualified.

Each of the 2026 Interim Results and 2025 Annual Report have been filed with, or notified to, the FCA and are available for inspection in accordance with paragraph 16 of Part 7 (*Additional Information*) of this document.

PART 6

TAXATION

The statements set out below are intended only as a general guide to certain aspects of current UK tax law and HMRC published practice (which may not be binding on HMRC) as at the date of this document, both of which are subject to change, possibly with retrospective effect. They relate only to certain limited aspects of the United Kingdom taxation treatment of Shareholders and are intended to apply only to certain Shareholders resident for tax purposes in the UK (save where express reference is made to non-UK resident persons) and to whom “split-year” treatment does not apply.

The summary does not purport to be a complete analysis or listing of all the potential tax consequences relating to acquiring, holding or disposing of Ordinary Shares. The statements below are not applicable to all categories of Shareholders, and in particular are not addressed to (i) Shareholders who do not hold their Ordinary Shares as capital assets or investments and/or who are not the absolute beneficial owners of those shares or dividends in respect of those shares; (ii) Shareholders who own (or are deemed to own) ten per cent. or more of the voting power of the Company; (iii) special classes of Shareholders such as dealers in securities, broker-dealers, insurance companies, trustees of certain trusts and investment companies; (iv) Shareholders who hold Ordinary Shares as part of hedging or commercial transactions; (v) Shareholders who hold Ordinary Shares in connection with a trade, profession or vocation carried on in the UK (whether through a branch or agency or otherwise); (vi) Shareholders who hold Ordinary Shares acquired by reason of their employment (or who are deemed to so hold Ordinary Shares); (vii) Shareholders who hold Ordinary Shares in a personal equity plan or an individual savings account; or (viii) Shareholders who are not resident in the UK for tax purposes (save where express reference is made to non-UK resident Shareholders).

The material set out in the paragraphs below does not constitute tax advice. Shareholders or prospective Shareholders who are in any doubt about their tax position, or who are resident or otherwise subject to taxation in a jurisdiction outside the United Kingdom are advised to consult their own independent tax advisers immediately. In particular, Shareholders or prospective Shareholders should be aware that the tax legislation of any jurisdiction where they are resident or otherwise subject to taxation may have an impact on the tax consequences of an investment in the Ordinary Shares including in respect of any income received from the Ordinary Shares.

1. Taxation of Dividends

The Company will not be required to withhold amounts on account of United Kingdom tax at source when paying a dividend (whether the payment is made to a UK resident shareholder, or a non-UK resident shareholder).

1.1 Individual shareholders

Dividends received by a United Kingdom resident individual Shareholder from the Company will generally form part of the Shareholder’s total income for income tax purposes and be subject to tax as dividend income.

UK resident individuals are entitled to a nil rate of income tax on the first £500 of dividend income in the tax year 2026/2027 (the “**Dividend Allowance**”). Any dividend income received by a UK resident individual Shareholder in respect of the Ordinary Shares in excess of the Dividend Allowance (taking account of any other dividends and dividend distributions received by the Shareholder in the same tax year) will be subject to income tax, for the tax year 2026/2027 at a rate of 10.75 per cent. to the extent that it is within the basic rate income tax band (the “dividend ordinary rate”), 35.75 per cent. to the extent that it is within the higher rate income tax band (the “dividend upper rate”) and 39.35 per cent. to the extent that it is within the additional rate income tax band (the “dividend additional rate”).

Dividend income that is within the Dividend Allowance counts towards an individual’s basic or higher rate income tax limits and will therefore affect the level of savings allowance to which they are entitled, and the rate of tax that is due on any dividend income in excess of the Dividend Allowance. For the purposes of determining which of the taxable bands dividend income in excess of the Dividend Allowance falls into, savings and dividend income are treated as the highest part of an individual Shareholder’s total income in computing a person’s overall tax liability. Where an individual

has both savings and dividend income, the amounts taken together are treated as the highest part of their total income, and the dividend income is taken as the highest part of the combined amount.

1.2 Corporate Shareholders

Shareholders within the charge to UK corporation tax that are “small companies” (for the purposes of the UK taxation of dividends) will generally be exempt from corporation tax on dividends from the Company provided that certain conditions are met (including an anti-avoidance condition).

Other Shareholders who are within the charge to United Kingdom corporation tax will be subject to corporation tax on dividends paid by the Company, unless (subject to special rules for such Shareholders that are small companies) the dividends fall within an exempt class and certain other conditions are met.

Other Shareholders within the charge to UK corporation tax (which are not “small companies” for the purposes of the UK taxation of dividends) should not be subject to UK corporation tax on dividends from the Company, so long as the dividends fall within an exempt class and certain conditions are met. In general: (i) dividends paid on non-redeemable “ordinary shares” (that is, non-redeemable shares that do not carry any present or future preferential rights to dividends or to the Company’s assets on its winding up); and (ii) dividends paid to a UK resident corporate Shareholder holding less than 10 per cent. of the issued share capital of the payer (or, if there is more than one class of share, less than 10 per cent. of the issued share capital of the same class of that share capital in respect of which the dividend is paid), should fall within an exempt class and accordingly should not be subject to UK corporation tax. However, it should be noted that the exemptions are not comprehensive and are subject to anti-avoidance rules. If the conditions for exemption are not met or such anti-avoidance rules do apply, such corporate Shareholders will be subject to UK corporation tax on dividends received from the Company at the rate appropriate to that corporate Shareholder. Shareholders will need to ensure that they satisfy the requirements of an exempt class and that no anti-avoidance rules apply before treating any dividend as exempt, and seek appropriate professional advice where necessary.

1.3 Non-UK shareholders

A Shareholder resident or otherwise subject to tax outside the United Kingdom (whether an individual or a body corporate) may be subject to foreign taxation on dividend income under local law. Shareholders to whom this may apply should obtain their own tax advice concerning tax liabilities on dividends received from the Company.

2. Taxation of Chargeable Gains

Shareholders who are resident in the United Kingdom, or, in the case of individuals, who cease to be resident in the United Kingdom for a period of five years or less, may depending on their circumstances (including the availability of exemptions or reliefs), be liable to United Kingdom taxation on chargeable gains in respect of gains arising from a sale or other disposal of Ordinary Shares.

2.1 Individual Shareholders within the charge to United Kingdom capital gains tax

A disposal (or deemed disposal) of Ordinary Shares may, depending on the circumstances and subject to any available exemption or relief, give rise to a chargeable gain (or an allowable loss) for the purposes of United Kingdom capital gains tax.

UK-resident individual Shareholders ordinarily have an annual exemption, such that capital gains tax is chargeable only on gains arising from all sources during the tax year in excess of this figure, and subject to any available relief. The annual exempt amount is £3,000 for the tax year 2026/2027.

Based on rates applicable for the tax year 2026/27, capital gains tax on share disposals by a UK resident individual Shareholder will generally be charged at 18 per cent. to the extent that the total chargeable gains and total taxable income arising in the tax year of disposal, after all allowable deductions (including losses, the income tax personal allowance and the capital gains tax annual exempt amount), are less than the upper limit of the income tax basic rate band. To the extent that any chargeable gains (or part of any chargeable gains) arising in the tax year of disposal exceed the upper limit of the income tax basic rate band when aggregated with any such income (in the manner referred to above), capital gains tax will generally be charged at 24 per cent.

Individuals who are temporarily non-resident for UK tax purposes may, in certain circumstances, be subject to tax in respect of gains realised while they are not resident in the United Kingdom.

2.2 Corporate Shareholders within the charge to United Kingdom corporation tax

Where a Shareholder is within the charge to UK corporation tax, a disposal (or deemed disposal) of Ordinary Shares may, depending on the circumstances and subject to any available exemption or relief, give rise to a chargeable gain (or an allowable loss) for the purposes of UK corporation tax. The main rate of UK corporation tax is currently 25 per cent. (the rate is 19 per cent. if the Shareholder is eligible for the small profits rate of corporation tax and is a marginal rate if the Shareholder's profits are between £50,000 and £250,000).

A non-UK corporate Shareholder that disposes of shares that are attributable to a UK permanent establishment through which it carries on a trade or business would generally be subject to corporation tax on the gain arising on the disposal of the Ordinary Shares in a similar way to a UK corporate Shareholder.

3. Inheritance Tax

The Ordinary Shares will be assets situated in the United Kingdom for the purposes of United Kingdom inheritance tax. A gift of such assets by, or the death of, an individual holder of such assets may (subject to certain exemptions and reliefs) give rise to a liability to United Kingdom inheritance tax, irrespective of whether the holder is a long-term UK resident. Generally, United Kingdom inheritance tax is not chargeable on gifts to individuals if the transfer is made more than seven complete years prior to death of the donor. For inheritance tax purposes, a transfer of assets at less than full market value may be treated as a gift and particular rules apply to gifts where the donor reserves or retains some benefit. Special rules also apply to close companies and to trustees of settlements who hold shares in the Company bringing them within the charge to inheritance tax. Holders of Ordinary Shares should consult an appropriate professional adviser if they make a gift of any kind or intend to hold any Ordinary Shares through such a company or trust arrangement. They should also seek professional advice in a situation where there is potential for a double charge to United Kingdom inheritance tax and an equivalent tax in another country or if they are in any doubt about their United Kingdom inheritance tax position.

Furthermore, following Admission, the Ordinary Shares will not benefit from certain UK inheritance tax reliefs and exemptions that may be applicable to shares traded on AIM. In particular, following Admission, the Ordinary Shares will not qualify for business relief for inheritance tax purposes (as may have otherwise been the case, had the Ordinary Shares continued to be traded on AIM). Individuals and trustees who may be subject to inheritance tax in relation to a shareholding in the Company who are concerned with the potential UK inheritance tax should consult their own tax adviser. This document is not a substitute for independent tax advice. See also risk factor 4.5 *"The Ordinary Shares will no longer benefit from certain UK tax reliefs available in relation to companies admitted to trading on AIM"* in the section of this document entitled *"Risk Factors."*

4. Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

On 13 July 2026 the UK Government published draft legislation of the implementation of a new Securities Transfer Tax Regime which is expected to replace the existing stamp duty and SDRT regimes. The commencement date of this regime is not yet known (HMRC has noted the intention is for the regime to be implemented in 2027).

The statements in this section are intended as a general guide to the current United Kingdom stamp duty and SDRT position based on the law in force as at the date of this document. They apply to all Shareholders, including Shareholders who are not resident or domiciled in the UK. Special rules apply to certain transactions such as transfers of Ordinary Shares to a company connected with the transferor and those rules are not described below. Investors should also note that certain categories of person are not liable to stamp duty or SDRT and others may be liable at a higher rate or may, although not primarily liable for tax, be required to notify and account for SDRT under the Stamp Duty Reserve Tax Regulations 1986.

4.1 Issues

No stamp duty or SDRT will arise on the issue of Ordinary Shares by the Company.

4.2 Transfers outside of Depositary Receipt Systems and Clearance Services

An agreement to transfer Ordinary Shares will normally give rise to a charge to SDRT at the rate of 0.5 per cent. of the amount or value of the consideration payable for the transfer. SDRT is, in general, payable by the purchaser.

Transfers of Ordinary Shares will generally be subject to stamp duty at the rate of 0.5 per cent. of the consideration given for the transfer (rounded up to the next £5 on each instrument of transfer). The purchaser normally pays the stamp duty. An exemption from stamp duty is available on an instrument transferring Ordinary Shares where the amount or value of the consideration is £1,000 or less and it is certified that the instrument and the transaction effected by the interest does not form part of a larger transaction or series of transactions in respect of which the aggregate amount or value of the consideration exceeds £1,000.

If a duly stamped transfer completing an agreement to transfer is produced within six years of the date on which the agreement is made (or, if the agreement is conditional, the date on which the agreement becomes unconditional) any SDRT already paid is generally repayable, normally with interest, and any SDRT charge yet to be paid is cancelled.

4.3 Growth market exemption

An exemption from stamp duty and SDRT is ordinarily available on instruments and transfers of securities trading on recognised growth markets. Whilst AIM is recognised as a growth market for these purposes, the Main Market is not. Following Admission, the Ordinary Shares will be admitted to the Official List and traded on the Main Market and as a result will not qualify for this stamp duty and/or SDRT exemption (as may have otherwise been the case had the Ordinary Shares continued to be traded on AIM).

4.4 Transfers within CREST

Paperless transfers of Ordinary Shares within the CREST system are generally liable to SDRT, rather than stamp duty, at the rate of 0.5 per cent. of the amount or value of the consideration payable. CREST is obliged to collect SDRT on relevant transactions settled within the CREST system. Deposits of Ordinary Shares into CREST will not generally be subject to SDRT or stamp duty, unless the transfer into CREST is itself for consideration.

4.5 Depositary Receipt Systems and Clearance Services

Special rules would apply if Ordinary Shares were transferred: (i) to, or to a nominee or an agent for, a person whose business is or includes the provision of clearance services; or (ii) to, or to a nominee or an agent for, a person whose business is or includes issuing depositary receipts (including, in each case, within CREST to a CREST account of such a person). In such circumstances, stamp duty or SDRT may be payable at the higher rate of 1.5 per cent. of the amount or value of the consideration given or, in certain circumstances, the value of the shares. Similarly, special rules would apply to the transfer of Ordinary Shares within a clearance service or in respect of agreements to transfer interests in depositary receipts. **Accordingly, specific professional advice should be sought in relation to stamp duty and SDRT if the Ordinary Shares are to be transferred to, within or via a clearance service or depositary receipt system.**

PART 7

ADDITIONAL INFORMATION

1. RESPONSIBILITY

- 1.1 The Company and the Directors, whose names appear on page 33 of this document, accept responsibility for the information contained in this document. To the best of the knowledge of the Company and the Directors, the information contained in this document is in accordance with the facts and this document makes no omission likely to affect its import.
- 1.2 Sproule ERCE accepts responsibility for the Sproule ERCE CPR. Sproule ERCE has used and relied upon data, information and materials made available by Serica Energy (UK) Limited, a wholly owned subsidiary of the Company, and Sproule ERCE confirms that, to the best of its knowledge, the information contained in the Sproule ERCE CPR is in accordance with the facts and that the Sproule ERCE CPR makes no omission likely to affect its import. The Sproule ERCE CPR was prepared at the request of Serica Energy (UK) Limited. Sproule ERCE has no interest in the share capital of the Company nor any member of the Group.

2. THE COMPANY

- 2.1 The Company was incorporated and registered in England and Wales on 12 May 2005 under the Companies Act as a public limited company with its current name, “Serica Energy plc”, and with the registered number 05450950. The Company’s LEI is 213800EZZOKA815VC426. The principal legislation under which the Company operates, and under which the Ordinary Shares have been created, is the Companies Act 2006.
- 2.2 The Company is domiciled in the United Kingdom. Its registered office is 4th Floor, 72 Welbeck Street, London, W1G 0AY and its telephone number is +44(0) 20 7487 7300. The Company’s website is www.serica-energy.com. The contents of the Company’s website (other than the information set out in Part 8 (*Documents Incorporated by Reference*) of this document) do not form part of this document and should not be relied on.
- 2.3 The Company’s current statutory auditor is BDO LLP, having its registered office at 55 Baker Street, London, United Kingdom, W1U 7EU. BDO LLP is a member firm of the Institute of Chartered Accountants in England and Wales. The Company’s statutory auditor for the financial year ended 31 December 2025 was Ernst & Young LLP, having its registered office at 1 More London Place, London, United Kingdom, SE1 2AF. Ernst & Young LLP is a member firm of the Institute of Chartered Accountants in England and Wales.

3. SHARE CAPITAL

- 3.1 As at the Latest Practicable Date, the issued share capital of the Company comprised 393,568,407 Ordinary Shares of \$0.10 each, all of which were fully paid or credited as fully paid, and one ‘A’ Share of £50,000, which is fully paid. The ‘A’ Share was allotted on 1 September 2005 to Serica Energy Corporation as trustee for and on behalf of the holders of the Ordinary Shares.
- 3.2 As at the Latest Practicable Date:
 - (a) the Company does not hold any shares in treasury;
 - (b) the Company does not have any convertible securities, exchangeable securities or securities with warrants; and
 - (c) except for rights to acquire Ordinary Shares under existing share option plans and employee share schemes (including the Serica Energy plc 2017 Long Term Incentive Plan), there are no acquisition rights and / or obligations over authorised but unissued capital of the Company and the Company has not given any undertaking to increase the capital.
- 3.3 The Ordinary Shares are in registered form and are capable of being held in certificated and uncertificated form. Title to the certificated Ordinary Shares are evidenced by entry in the register of members of the Company and title to uncertificated Ordinary Shares are evidenced by entry in the operator register maintained by the registrar (which forms part of the register of members of the Company). No share certificates are issued in respect of Ordinary Shares in uncertificated form.

- 3.4 The Ordinary Shares are (as at the date of this document) admitted to trading on AIM. Applications have been made to the FCA and the London Stock Exchange for the admission of all of the Ordinary Shares to the equity shares (commercial companies) category of the Official List and the London Stock Exchange's Main Market, respectively. It is expected that Admission will become effective and that dealings in the Ordinary Shares on the London Stock Exchange will commence at 8.00 a.m. on 27 October 2026. No application has been, or is currently intended to be, made for the Ordinary Shares to be admitted to listing or trading on any other exchange.
- 3.5 The Ordinary Shares are registered with ISIN GB00B0CY5V57 and, from Admission, will trade under the symbol "SER".

4. ARTICLES OF ASSOCIATION

The following is a summary of the Articles, which are available for inspection as described in paragraph 16 of this Part 7 (*Additional Information*). The Articles, which were adopted on 21 May 2026, contain provisions, among others, to the following effect:

4.1 Objects

The Company has no statement of objects in its Articles and accordingly its objects are unrestricted in accordance with the provisions of the Companies Act.

4.2 Limited Liability

The liability of the members is limited to the amount, if any, unpaid on the shares held by them.

4.3 Votes of members

Subject to paragraph 4.7 below and to applicable law:

- (a) on a show of hands, every member or authorised corporate representative present has one vote and every proxy present has one vote except that a proxy has one vote for and one vote against the resolution if the proxy has been duly appointed by more than one member and has been instructed by (or exercises his discretion given by) one or more of those members to vote for the resolution and has been instructed by (or exercises his discretion given by) one or more other of those members to vote against it;
- (b) on a poll, every member present in person or by proxy or by corporate representative has one vote for every share of which he is the holder or in respect of which his appointment as proxy or corporate representative has been made.

The holders(s) of the 'A' Share is entitled to the same voting rights as the holders of Ordinary Shares.

4.4 Transfer of Shares

A Shareholder may transfer all or any of their Ordinary Shares (a) in the case of shares in certificated form, by an instrument of transfer in any usual form, or in such other form as the Board may approve; and (b) in the case of shares in uncertificated form, by means of the relevant system concerned.

The Board may, in its absolute discretion, refuse to register any transfer of any share which is not fully paid up (but not so as to prevent dealings in listed shares from taking place on an open and proper basis). The Board may also refuse to register any transfer of a share in favour of more than four persons jointly.

In addition, in relation to a certificated share, the Board may decline to recognise an instrument of transfer unless it is: (a) duly stamped (if stampable), is left at the Company's registered office, or at such other place as the Directors may from time to time determine, accompanied by the share certificate(s) to which it relates and such other evidence as the Directors may require; and (b) in respect of only one class of share.

The holder(s) of the 'A' Share is not entitled to sell, transfer, renounce, charge, donate or otherwise dispose of the 'A' Share (or any interest therein), save upon any change of trustee to new or remaining trustees of the trust or settlement, the beneficiaries or potential beneficiaries of which are exclusively all Shareholders.

4.5 Dividends

The Shareholders are entitled to receive, from time to time, upon determination by the Directors (whose decision shall be final), a dividend subject to the Company having sufficient distributable reserves and

subject to the withholding of any applicable taxes (as the case may be). The Company may by ordinary resolution declare dividends to Shareholders provided that no dividend shall exceed the amount recommended by the Directors. The Directors may from time to time declare and pay such interim dividends as they think fit, and declare and pay fixed dividends on any shares on fixed dates.

Except as otherwise provided by the Articles or the rights attached to shares, all dividends will be declared and paid according to the amounts paid up on the shares on which the dividend is paid.

Subject to the rights attaching to the terms of issue of shares, no dividend or other money payable in respect of a share shall bear interest against the Company. Any dividend which has remained unclaimed for a period of 12 years from the date when it became due for payment will be forfeited and revert to the Company.

No dividend will be declared or paid to the holder(s) of the 'A' Share.

4.6 Return of Assets on a Winding Up

On a return of assets on liquidation or capital reorganisation or otherwise, the assets of the Company remaining after the payment of its liabilities will be applied, first, in paying to the holder(s) of the 'A' Share the sum of £50,000, and, second, in paying to the holders of the Ordinary Shares the balance of such assets in proportion to the amounts paid up on, or credited as paid up on, (excluding any premium) the Ordinary Shares held.

A liquidator may, with the authority of a special resolution of the Company, divide among the members in specie the whole or any part of the assets of the Company, and may for such purposes value any assets and determine how the division shall be carried out as between members or different classes of members. The liquidator may, with the like sanction, vest the whole or any part of the assets in trustees on trust for the benefit of the members as he may with the like sanction determine. No member will be compelled to accept any assets upon which there is a liability.

4.7 Suspension of Rights

If a member or any other person appearing to be interested in shares held by such member has been given a notice under section 793 of the Companies Act and has failed in relation to any shares (the “**default shares**”) to supply to the Company the information required under such notice within 14 days of the date of the notice, unless the Directors otherwise determine, (a) the member shall not be entitled in respect of the default shares to be present or to vote at any general meeting or at any separate meeting of holders of any class of shares or on any poll; and (b) where the default shares represents at least 0.25 per cent. of their class (excluding any shares held in treasury):

- any dividend payable in respect of the default shares may be withheld by the Company;
- other than in certain circumstances, no transfer of any default shares held in certificated form will be registered; and
- the directors may require the Operator of a relevant system to convert the default shares into certificated form to enable the Company to deal with the default shares in accordance with the Articles.

Any new shares in the Company issued in right of default shares will be subject to the same sanctions as apply to the default shares.

4.8 Pre-emption rights

The rights of holders of shares to participate pre-emptively in any allotment of equity securities are prescribed by the Companies Act. Shareholders may, by way of special resolution, grant authority to the Directors to disapply statutory pre-emption rights. At the annual general meeting of the Company held on 21 May 2026, Shareholders granted such powers to the Directors to allot equity securities of up to an aggregate nominal amount of \$3,930,264.23 for cash as if such statutory pre-emption rights did not apply.

5. Major Shareholders

Insofar as it is known to the Company as at the Latest Practicable Date, the following persons are interested directly or indirectly in 3 per cent. or more of the total voting rights of the Company:

Shareholder	Number of Ordinary Shares	Percentage of issued share capital (%)
Mercuria Holdings (UK) Limited ⁽¹⁾	96,618,142	24.55
Mr D and Mrs D Hardy	31,845,605	8.09
Interactive Investor	24,120,085	6.13
Hargreaves Lansdown, stockbrokers	21,085,617	5.36
Orbis Investment Management	15,814,813	4.02
Blackrock	12,248,146	3.11

Note:

(1) An indirect wholly-owned subsidiary of Mercuria Energy Group Limited. MDJ Partnership, a Guernsey partnership, holds 100 per cent. of the issued share capital of MDJ Oil Trading Limited, which indirectly owns a majority stake in Mercuria Energy Group Limited.

None of the major shareholders of the Company set out above has different voting rights from any other holder of Ordinary Shares in respect of any Ordinary Share held by them.

Insofar as is known to the Company, the Company is not, and will not be immediately following Admission, directly or indirectly, owned or controlled by another corporation, any foreign government, or any other natural or legal person, severally or jointly.

The Directors are not aware of any arrangements, the operation of which may at a subsequent date result in a change of control of the Company.

Shareholders are obliged to comply with the shareholding notification and disclosure requirements set out in Chapter 5 of the Disclosure Guidance and Transparency Rules. A Shareholder is required pursuant to Chapter 5 of the Disclosure Guidance and Transparency Rules to notify the Company if, as a result of an acquisition or disposal of shares or financial instruments, the Shareholder's percentage of voting rights of the Company reaches, exceeds or falls below, 3 per cent. of the total voting rights of the Company (or any 1 per cent. threshold above that).

6. Working capital statement

The Company is of the opinion that, taking into account the facilities available to the Group, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this document.

7. No significant change

There has been no significant change in the financial position or financial performance of the Group since 30 June 2026, being the date to which the Group's latest unaudited financial information was published.

8. Regulatory disclosures

The following is a summary of the information disclosed in accordance with the Company's obligations under UK MAR over the last 12 months which is relevant as at the date of this document:

Nature of information	Date of release
Results, trading and operational updates	
Trading and operations update in respect of Q3 2026	19 October 2026
Results for the six months ended 30 June 2026	6 August 2026
Announcement regarding capital markets day	2 June 2026
Fixed income investor meetings and update on current trading	24 April 2026
Results for the year ended 31 December 2025	26 March 2026
Trading and operations update in respect of the year ended 31 December 2025	21 January 2026
Trading and operations update in respect of Q3 2025	27 November 2025

Nature of information	Date of release
Financing	
Pricing of Nordic bond issue	29 April 2026
Acquisitions	
Termination of Serica Offer for Pharos Energy plc	13 August 2026
Statement regarding final offer for Pharos Energy plc	10 August 2026
Recommended acquisition of Pharos Energy plc	27 July 2026
Acquisition of assets from Spirit Energy Limited and affiliates	16 December 2025
Update on proposed acquisition of UK North Sea assets from BP	10 November 2025
PDMR dealings	
PDMR dealing notification regarding an acquisition of shares	16 December 2025

9. Material contracts

The following section provides a summary of (a) material contracts (other than contracts entered into in the ordinary course of business) entered into by the Company or another member the Group in the two years immediately preceding the date of this document; and (b) any other contracts (not being contracts entered into in the ordinary course of business) entered into by a member of the Group which contain any provisions under which any member of the Group has any obligation or entitlement which is material to the Group as at the date of this document.

9.1 Sponsor Agreement

On 21 October 2026, the Company and Peel Hunt entered into a sponsor agreement (the “**Sponsor Agreement**”), pursuant to which Peel Hunt agreed to act as sponsor to the Company under the UK Listing Rules in connection with Admission and the publication of this document, as required under the UK Listing Rules.

Under the terms of the Sponsor Agreement, the Company agreed to provide certain customary warranties, representations and undertakings in favour of Peel Hunt as sponsor in relation to, among other matters, the accuracy of information in this document, and other matters relating to the Group and its business. The Company has also agreed to indemnify Peel Hunt and its affiliates, on customary terms and subject to certain exceptions, against claims made against them and losses incurred by them, in connection with this document and Admission. The Company has agreed to pay Peel Hunt a sponsor fee and certain costs and expenses in connection with Admission.

9.2 RBL Facility

Overview

On 22 July 2026, Serica Energy Holdco UK Limited, the Company and DNB Bank ASA, London Branch (as agent and security trustee), among others, entered into an amendment and restatement agreement in respect of a six-year senior \$750 million secured revolving reserve-based lending facility (the “**RBL Facility**”). The RBL Facility replaces the Group’s previous \$525 million reserves-based lending facility.

The RBL Facility comprises a \$500 million secured revolving loan facility and a \$250 million secured revolving letter of credit facility. There is an uncommitted accordion option for additional financing of up to \$750 million, providing the potential to extend the loan facility by up to \$500 million and the letter of credit facility by up to \$250 million, taking potential total facilities to \$1,500 million. The accordion option can be exercised up to 30 June 2029, subject to certain conditions. As at the date of this document, the RBL Facility remains undrawn.

The proceeds of the loan facility may be applied towards, among other things, ongoing operating expenses and capital expenditure and working capital and general corporate purposes (including certain permitted acquisitions). The letter of credit facility may be used for the purposes of providing security, credit enhancement or financial assurance relating to the Group’s obligations. The RBL Facility may not be used in relation to any activity relating to or in connection with funding the Rhum field and/or Rhum-related equipment or infrastructure.

The RBL Facility is drafted on the basis of a customary reducing borrowing base facility arrangement whereby the maximum amount that can be drawn or outstanding on any date shall be the lesser of the total commitments (being \$750 million at the facility signing date) and the borrowing base amount. The borrowing base amount is calculated by reference to the field life and loan life net present value of the

borrowing base assets prior to each semi-annual redetermination date. The borrowing base amount will be approved by the lenders on each redetermination date.

Under the RBL Facility, if at any time 50 per cent. or more of the amount available is drawn, the minimum commodities hedging requirement is equal to 50 per cent. of forecast production from the borrowing base assets in the following year and 30 per cent. in the subsequent year. The hedging requirement is halved if less than 50 per cent. of the amount available is drawn.

Security

The lenders benefit from security over all of Serica's interests in producing fields with the exception of the Rhum field.

Repayment and Maturity

The RBL Facility will mature on 30 June 2032, but with a springing maturity linked to the maturity of the Nordic Bond. The RBL Facility is a revolving facility and subject to semi-annual reductions in accordance with an amortisation schedule, commencing on 30 June 2029.

Interest

The interest rate for loan drawings on the RBL Facility is SOFR plus a margin of 3.50 per cent. per annum until the second anniversary of the facility signing date, 3.75 per cent. from the second anniversary until the fourth anniversary of the facility signing date, and 4 per cent. from the fourth anniversary of the facility signing date until the maturity date.

Covenant Package

The RBL Facility contains customary representations and covenants, including representations as to status, binding obligations, non-conflict with other obligations, power and authority, projection assumptions preparation, group liquidity test, environmental matters, project documents and field interests, that are in certain cases subject to knowledge and materiality qualifications, and also including covenants as to authorisations, disposals, acquisitions, field operations, insurances and distributions.

The RBL Facility includes a financial covenant that Serica shall maintain a total net debt / adjusted EBITDAX cover ratio below 3.50x, which is tested semi-annually.

The RBL Facility contains customary events of default including breach of financial ratios, non-payment, breach of other obligations under the finance documents, insolvency and analogous proceedings, cross-default, misrepresentation, the qualification of accounts, repudiation and effectiveness, litigation and material adverse change. There are additional events of default relating to the borrowing base assets.

9.3 \$300 million Nordic Bond

On 12 May 2026, the Group successfully completed the placement of senior unsecured bonds issued by the Company with a principal amount of \$300 million and a maturity of five years (the "**Nordic Bond**"). The Nordic Bond bear interest at a fixed coupon rate of 7.875 per cent. per annum, payable 6-monthly in arrears.

The net proceeds from the Nordic Bond were used primarily to repay in full the outstanding drawn balance under the Group's previous reserves-based lending facility and to strengthen the Group's liquidity position.

The terms of the Nordic Bond include a financial covenant that Serica shall maintain a total net debt / adjusted EBITDAX cover ratio below 3.50x, which is tested semi-annually. It also requires Serica to maintain free cash flow of not less than 5 per cent. of its capital markets financial indebtedness at any time.

The terms of the Nordic Bond contain customary events of default including non-payment, breach of obligations under the finance documents, insolvency and analogous proceedings, cross-default, misrepresentation and unlawfulness.

9.4 Relationship Agreement

The Company and Mercuria entered into a relationship agreement dated 23 March 2023 following completion of the Tailwind Acquisition. Pursuant its terms, Mercuria may terminate the existing relationship agreement if the Company's shares cease to be admitted to trading on AIM.

Accordingly, the Company and Mercuria have entered into an amendment and restatement agreement dated 21 October 2026, to amend and restate the relationship agreement (the “**Amended Relationship Agreement**”) on substantially similar terms to the existing relationship agreement to regulate the continuing relationship between Serica and Mercuria on and after Admission. The existing relationship agreement terminates, and the Amended Relationship Agreement becomes effective, on Admission.

In particular Mercuria has agreed, subject to certain customary exceptions, that:

- neither it nor any of its affiliates shall seek to undermine the principle of independence of Serica;
- all transactions and arrangements between Mercuria and any of its affiliates and Serica will be conducted on arm’s length and normal commercial terms;
- neither it nor its affiliates shall exercise their voting or other rights or powers to procure amendments to the Articles in a manner which would be inconsistent with or breach the Amended Relationship Agreement;
- neither it nor its affiliates will take any action that would prevent Serica from complying with the UK Listing Rules, the DTRs or UK MAR; and
- neither it nor its affiliates will propose or procure the proposal of a shareholder resolution which is intended to circumvent the proper application of the UK Listing Rules.

Pursuant to the Amended Relationship Agreement, and similar to the existing relationship agreement, Mercuria is entitled to nominate two non-executive directors to the Board as long as the shareholding of Mercuria and its affiliates is 20 per cent. or above and one non-executive director for so long as the shareholding of Mercuria and its affiliates is between 10 per cent. or above and less than 20 per cent. If and for so long as the Board exceeds 11 directors, Mercuria may nominate a third non-executive director for so long as the shareholding of Mercuria and its affiliates remains at 20 per cent. or above of Serica’s issued share capital.

The Amended Relationship Agreement will terminate if Mercuria and its affiliates hold in aggregate less than 10 per cent. of Serica’s issued share capital and may be terminated by Mercuria if, among other circumstances, Serica’s shares cease to be admitted to the Official List.

9.5 BKR Acquisition Agreements

The Group acquired its interests in BKR pursuant to the following agreements. Completion of the acquisitions referred to below occurred in November 2018.

(a) BP SPA

Pursuant to an acquisition agreement dated 21 November 2017 between BP Exploration Operating Company Limited (“**BP**”) and Serica UK (the “**BP SPA**”), Serica UK agreed to acquire 36 per cent. in the Bruce field (BP is retaining 1 per cent.), BP’s entire 34.83 per cent. interest in the Keith field and BP’s entire 50 per cent. interest in the Rhum field. Certain elements of the consideration payable by Serica UK under the BP SPA remain outstanding, being:

- an additional consideration equal to 30 per cent. of BP’s retained share of decommissioning costs when due, reduced by the tax relief that BP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the acquisition of the relevant interests in BKR from BP; and
- deferred consideration equal to 90 per cent. of its share of the realised value of oil in the Bruce pipeline at the end of field life.

(b) Total E&P SPA

Pursuant to an acquisition agreement dated 2 August 2018 between Total E&P UK Limited (now known as NEO NEXT+ Energy UK Limited) (“**Total E&P**”) and Serica UK (the “**Total E&P SPA**”), Serica UK agreed to acquire Total E&P’s interests in the Bruce and Keith fields in the North Sea (save for a 1 per cent. interest in the Bruce field which is being retained by Total E&P). Certain elements of the consideration payable by Serica UK under the Total E&P SPA remain outstanding, being:

- an additional consideration equal to 30 per cent. of Total E&P’s retained share of decommissioning costs when due, reduced by the tax relief that Total E&P receives on those

costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the acquisition; and

- deferred consideration equal to 90 per cent. of its share (net to the assets being acquired) of the realised value of oil in the Bruce pipeline at the end of field life.

(c) *BHP SPA*

Pursuant to an acquisition agreement dated 2 November 2018 between BHP Billiton Petroleum Great Britain Limited (“**BHP**”) and Serica UK (the “**BHP SPA**”), Serica UK agreed to acquire BHP’s interests in the Bruce and Keith fields in the North Sea. Certain elements of the consideration payable by Serica UK under the BHP SPA remain outstanding, being:

- an additional consideration equal to 30 per cent. of BHP’s retained share of decommissioning costs when due, reduced by the tax relief that BHP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the acquisition; and
- deferred consideration equal to 90 per cent. of its share (net to the assets being acquired) of the realised value of oil in the Bruce pipeline at the end of field life.

(d) *Marubeni SPA*

Pursuant to an acquisition agreement dated 5 November 2018 between Marubeni Oil & Gas (U.K.) Limited (“**Marubeni**”) and Serica UK (the “**Marubeni SPA**”), Serica UK agreed to acquire Marubeni’s interests in the Bruce and Keith fields in the North Sea. Under the Marubeni SPA, Serica UK agreed to assume liability for all the costs of decommissioning facilities and wells relating to the assets being acquired under the Marubeni SPA.

9.6 Tailwind Acquisition Agreement

The Company and Tailwind Energy Holdings LLP entered into a share purchase agreement dated 20 December 2022 (the “**Tailwind Acquisition Agreement**”) pursuant to which the Company agreed to acquire 100 per cent. of the shares in Tailwind Energy Investments Limited (now, Serica Energy Investments Limited). The consideration for the acquisition comprised the issue of 96,618,142 Ordinary Shares and a cash payment of £61.6 million. The acquisition completed on 23 March 2023.

Pursuant to the terms of the Tailwind Acquisition Agreement, as is customary, the Company agreed to provide an indemnity (uncapped in amount or time) to Tailwind Energy Holdings LLP (as the seller), Mercuria and the founders (being, Stephen Edwards, Jacques Tohme, Tomasz Ujejski and David Freeman) for any decommissioning and/or environmental liabilities in relation to the target group.

9.7 Triton Hub Acquisition Agreements

The Group acquired its interests in the Triton Hub pursuant to the following agreements. These agreements were entered into by Serica Energy Investments Limited (previously Tailwind Energy Investments Limited) prior to the Tailwind Acquisition.

(a) *Shell SPA*

Serica Energy Investments Limited, Shell U.K. Limited and Shell EP Offshore Ventures Limited entered into an acquisition agreement dated 20 December 2017 (the “**Shell SPA**”) pursuant to which Serica Energy Investments agreed to acquire Shell’s interests in the licences and related licence interest documents in relation to the Bittern field, the Gannet E field and the Triton FPSO. The consideration for the acquisition included a royalty payment which would become payable if a certain production threshold is met.

Pursuant to the terms of the Shell SPA, as is customary, the Company agreed to provide an indemnity (uncapped in amount or time) to Shell U.K. Limited and Shell EP Offshore Ventures Limited (as the sellers) and their associated parties for any decommissioning and environmental liabilities in relation to its percentage in the interests acquired. The sellers agreed, however, to retain a portion of such decommissioning and environmental liabilities, subject to a monetary cap.

(b) *Esso SPA*

Esso Exploration and Production UK Limited (“**Esso E&P UK**”) and Serica Energy Investments Limited entered into an acquisition agreement dated 20 December 2017 (the “**Esso SPA**”) pursuant to

which Serica Energy Investments agreed to acquire Esso E&P UK's interests in the licences and related licence interest documents in relation to the Bittern field area, the Gannet E field and the Triton FPSO. The consideration for the acquisition included a royalty payment which would become payable if a certain production threshold is met.

Pursuant to the terms of the Esso SPA, as is customary, Serica Energy Investments agreed to provide an indemnity (uncapped in amount or time) to Esso E&P UK as the seller and its associated parties for decommissioning and environmental liabilities in relation to its percentage in the interests acquired. Esso E&P UK agreed, however, to retain a portion of such decommissioning and environmental liabilities, subject to a monetary cap.

(c) *Additional Esso SPA*

Serica Energy Investments Limited and Esso E&P UK entered into an acquisition agreement dated 20 December 2017 (the “**Additional Esso SPA**”) pursuant to which Serica Energy Investments agreed to acquire Esso E&P UK's interests in the licences and related licence interest documents in relation to Guillemot West Field and the Guillemot North West Field. The consideration for the acquisition included certain elements of deferred consideration, including a contingent consideration amount of \$5 million and a royalty payment which would become payable if a certain production threshold is met.

Pursuant to the terms of the Additional Esso SPA, as is customary, the Company agreed to provide an indemnity (uncapped in amount or time) to Esso E&P UK (as the seller) and its associated parties for any decommissioning liabilities in relation to its percentage of the interests acquired. Esso E&P UK agreed, however, to retain a portion of the decommissioning and environmental liabilities, subject to a monetary cap.

9.8 **Erskine Acquisition Agreement**

BP Exploration Operating Company Limited, Britoil Limited, Serica UK and the Company entered into an acquisition agreement dated 16 June 2014 (the “**Erskine Acquisition Agreement**”) pursuant to which Serica UK agreed to acquire interests in the licences and related licence interest documents in relation to the Erskine field.

Pursuant to the terms of the Erskine Acquisition Agreement, as is customary, Serica UK agreed to provide an indemnity (uncapped in amount or time) to BP Exploration Operating Company Limited and Britoil Limited (as the sellers) for decommissioning and environmental liabilities in relation to the interests. However, the sellers indemnify Serica UK for liabilities occurring prior to 1 January 2014, subject to a monetary cap. The Company has provided a guarantee in relation to Serica UK's obligations.

9.9 **Belinda Acquisition Agreement**

Serica Energy Investments Limited and Shell U.K. Limited entered into an acquisition agreement dated 20 December 2017 (the “**Belinda Acquisition Agreement**”) pursuant to which Serica Energy Investments agreed to acquire interests in the licences and related licence interest documents in relation to the Belinda field and the Evelyn field.

Pursuant to the terms of the Belinda Acquisition Agreement, as is customary, the Company agreed to provide an indemnity (uncapped in amount or time) to Shell U.K. Limited (as the seller) and its associated parties for any decommissioning and environmental liabilities in relation to the interests.

9.10 **Prax Upstream SPA**

On 29 September 2025, the Company, Prax Exploration & Production Plc (in Administration) (“**Prax E&P**”) and Prax E&P's joint administrators entered into a sale and purchase agreement (the “**Prax Upstream SPA**”), pursuant to which the Company agreed to acquire the entire issued share capital of Prax Upstream Limited for £14.5 million. The Prax Upstream Acquisition completed on 11 December 2025.

Pursuant to the terms of the Prax Upstream SPA, as is customary, the Company agreed to provide an indemnity (uncapped in amount or time) to Prax E&P (as the seller) and its associated parties (including Prax E&P's joint administrators) for any environmental and decommissioning liabilities in relation to its percentage of the interests in the assets acquired through the acquisition of Prax Upstream and its subsidiaries. Further, the Company agreed to provide an indemnity on customary terms (uncapped in amount or time) in respect of employment and pensions-related liabilities relating to employees of the target group, subject to limited exceptions.

Following completion of the Prax Upstream Acquisition, Serica assumed the rights and obligations of Prax Upstream in relation to the TTE Asset Acquisition and the ONE-Dyas Asset Acquisition.

9.11 TTE asset purchase agreement

On 29 September 2025, the Company, Prax Upstream and certain of its subsidiaries and Total E&P entered into a deed of amendment and restatement in relation to a sale and purchase agreement relating to interests in the Greater Laggan Area and Shetland Gas Plant originally entered on 20 June 2024 into between, among others, Prax Upstream, certain of its subsidiaries (together, the **“TTE Asset Purchasers”**) and Total E&P (as amended and restated, the **“TTE APA”**).

Pursuant to the TTE APA, TTE Asset Purchasers agreed to acquire Total E&P’s interests in the licences and related licence interest documents in relation to the GLA Assets and four near field exploration blocks. The consideration for the transfer of Total E&P’s interests was \$1.00, as adjusted by certain customary completion adjustments including net cashflows after tax from the GLA Assets between the economic date of 1 January 2024 and completion of the TTE APA. The TTE APA also provided for the transfer of certain minor land assets to Prax Upstream for £1. The TTE Asset Acquisition completed on 26 March 2026, upon which the TTE Asset Purchasers received a payment of \$56 million, reflecting interim post-tax cash flows between the economic date of 1 January 2024 and completion.

Total E&P (as the seller) and the TTE Asset Purchasers have each provided indemnities relating to the allocation of pre- and post-economic date benefits and liabilities. Total E&P are liable for all pre-economic date liabilities and entitled to all pre-economic date benefits and the TTE Asset Purchasers are liable for all post-economic date liabilities and entitled to all post-economic date benefits. The TTE Asset Purchasers have also agreed to provide an indemnity (uncapped in amount or time) to Total E&P as the seller and its associated parties for decommissioning and environmental liabilities in relation to its percentage in the interests acquired.

Total E&P has given warranties in favour of the TTE Asset Purchasers which are customary for a transaction of this nature, including in relation to the seller’s title and certain commercial and operational warranties relating to the assets. The seller’s liability in respect of claims made pursuant to the TTE APA is subject to certain customary financial and time limitations.

The Company has agreed to guarantee the Prax Purchaser’s obligations under TTE APA and any other document entered into by the parties in connection with the TTE APA.

In addition, Total E&P has agreed to provide certain transitional services to Prax Upstream until 27 March 2027 in connection with the acquisition of the interests in the Greater Laggan Area and Shetland Gas Plant.

9.12 ONE-Dyas acquisition agreement

On 28 March 2025, Prax Hurricane GLA Limited (a subsidiary of Prax Upstream) (**“Prax Hurricane GLA”**) and ONE-Dyas UK Limited (**“ONE-Dyas”**) entered into a put and call option deed (the **“Option Deed”**) relating to the sale and purchase of Serica Energy GEAD & Catcher Limited (previously known as ONE-Dyas GEAD & Catcher Limited) (**“GEAD & Catcher Target”**). Subsequently, on 29 September 2026, Prax Hurricane GLA and ONE-Dyas entered into an amendment letter pursuant to which the parties agreed to make certain amendments to the Option Deed.

Under the terms of the Option Deed (as amended), ONE-Dyas granted Prax Hurricane GLA an option to purchase the entire issued share capital of GEAD & Catcher Target, following satisfaction of certain conditions, including completion of the transfer to GEAD & Catcher Target of ONE-Dyas’ interests in the licences and related licence interest documents in relation to the Greater Eagle Area Development (the **“GEAD Interest”**) and in relation to the Catcher Field (the **“Catcher Interest”**) and the exploration, development and production business carried on by ONE-Dyas in respect of the GEAD Interest and Catcher Interest.

The consideration for the transfer of GEAD & Catcher Target was \$6.75 million payable on completion, as adjusted by certain customary completion adjustments including net cashflows after tax from the Catcher Interest and GEAD Interest between the economic date of 1 January 2024 and completion. The ONE-Dyas Asset Acquisition completed on 11 June 2026, upon which Prax Hurricane GLA paid \$6.75 million, and received a payment of \$13.0 million, reflecting interim post-tax cashflows between the economic date of 1 January 2024 and the date of completion.

Pursuant to the terms of the Option Deed (as amended), as is customary, Prax Hurricane GLA agreed to provide an indemnity (uncapped in amount or time) to ONE-Dyas (as the seller) for decommissioning and

environmental liabilities in relation to the GEAD Interest and Catcher Interest, other than any such liabilities which accrued prior to 1 January 2024 and have been paid by ONE-Dyas (or its affiliates) prior to such date. Prax also agreed to indemnify ONE-Dyas in respect of claims relating to GEAD & Catcher Target (including in relation to the GEAD Interest and the Catcher Interest).

ONE-Dyas has given certain warranties in favour of Prax Hurricane GLA in relation to the seller's title, the transfer of the GEAD Interest and Catcher Interest to GEAD & Catcher Target and the GEAD Interest and Catcher Interest. The seller's liability in respect of claims made pursuant to the Option Deed (as amended) is subject to certain customary financial and time limitations.

9.13 Spirit Energy Portfolio SPA

On 16 December 2025, Prax Hurricane GWA Limited and Prax Hurricane (Whirlwind) Limited (together, the **"Spirit Portfolio Purchasers"**) and Spirit Energy Limited and certain of its affiliates (together, the **"Spirit Portfolio Sellers"**) entered into a sale and purchase agreement (the **"Spirit Energy Portfolio SPA"**) relating to interests in UK licences relating to the Greater Markham Area, Southern North Sea and Cygnus fields, and shares in Spirit Energy Nederland B.V. (the **"Portfolio"**).

The consideration for the Portfolio was £57 million (\$75 million), payable on completion, subject to customary working capital adjustments, and was significantly offset by the receipt of a payment reflecting interim post-tax cashflows between the effective economic date of 1 January 2025 and completion. The transaction completed on 1 October 2026, upon which the Spirit Portfolio Purchasers paid £33 million (\$43 million).

The Spirit Energy Portfolio SPA also include provision for two potential further cash payments by the Spirit Portfolio Purchasers: (a) £2.5 million contingent on sanction of the drilling of an additional development well on Cygnus; and (b) £1 million contingent on the drilling of, and subsequent first production from, an infill well on Clipper South.

The Spirit Portfolio Sellers and the Spirit Portfolio Purchasers have each provided indemnities relating to the allocation of pre- and post-economic date benefits and liabilities. The Spirit Portfolio Sellers are liable for all pre-economic date liabilities and entitled to all pre-economic date benefits and the Spirit Portfolio Purchasers are liable for all post-economic date liabilities and entitled to all post-economic date benefits.

The Spirit Portfolio Purchasers have also agreed to provide an indemnity (uncapped in amount or time) to the Spirit Portfolio Sellers and their associated parties for decommissioning and environmental liabilities in relation to their respective percentage in the interests acquired, save the Spirit Portfolio Sellers have agreed to retain decommissioning liabilities in respect of the Greater Markham Area, Eris and Ceres fields, which continue to be operated by the Spirit Portfolio Sellers (or their affiliates) following completion, up to a cap, set at 115 per cent. of the current estimated decommissioning costs.

The Spirit Portfolio Sellers have given warranties in favour of the Spirit Portfolio Purchasers which are customary for a transaction of this nature, including in relation to the sellers' title and certain commercial and operational warranties relating to the assets. The sellers' liability in respect of claims made pursuant to the Spirit Energy Portfolio SPA is subject to certain customary financial and time limitations.

10. SUMMARY OF SERICA'S LICENCE HOLDINGS

The following table summarises the Group's licences as at the Latest Practicable Date.

Licence	Block(s)	Description	Role	Licence Expiry Date ⁽¹⁾
Bruce Hub				
P090	9/9a Bruce	Bruce field production	Operator	— ⁽²⁾
P090	9/9a rest of block excluding Bruce (REST)	Rest of block	Operator	— ⁽²⁾
P198	3/29a (ALL)	Rhum field production	Operator	— ⁽³⁾
P209	9/8a Bruce	Bruce field production	Operator	— ⁽⁴⁾
P209	9/8a Keith	Keith field production	Operator	— ⁽⁴⁾
P209	9/8a rest of block excluding Bruce and Keith (REST)	Rest of block	Operator	— ⁽⁴⁾
P276	9/9b Bruce	Bruce field production	Operator	— ⁽⁵⁾
P276	9/9c (ALL)	Bruce field production	Operator	— ⁽⁵⁾
P276	9/9b rest of block excluding Bruce unit (REST)	Rest of block	Operator	— ⁽⁵⁾
P566	3/29b (ALL)	Rhum field production	Operator	— ⁽⁵⁾
P975	3/24b (ALL)	Rhum field production	Operator	22 December 2034
P975	3/29d (ALL)	Rhum field production	Operator	22 December 2034
Triton Hub				
P233	29/1a Bittern	Bittern	Operator	— ⁽⁵⁾
P361	29/1b	Bittern	Non-operator	— ⁽⁵⁾
P13	21/30c A	Gannet E	Operator	— ⁽²⁾
P13	21/25a UPPER, 21/30a UPPER	Gannet E/ Guillemot W	Non-operator	— ⁽²⁾
P215	21/29b	Guillemot W	Non-operator	— ⁽⁵⁾
P1792	21/30f	Evelyn	Operator	9 January 2037 (anticipated)
P1792	21/30i	Belinda	Operator	9 January 2037 (anticipated)
P2616	29/2c	Kyla (redevelopment)	Operator	30 November 2045 (anticipated)
P2643	21/30g	Triton FPSO	Non-operator	— ⁽⁶⁾
West of Shetland Hub				
P1368	205/21a P1368 C, 205/ 22a P1368 C	Lancaster	Operator	— ⁽⁷⁾
P911	206/1a ALL	Laggan	Operator	8 June 2031 (anticipated)

Licence	Block(s)	Description	Role	Licence Expiry Date⁽¹⁾
P1159	205/5a, 205/5d	Laggan/ Tormore	Operator	30 November 2034 (anticipated)
P1678	205/4b	Tormore	Operator	11 February 2035 (anticipated)
P1195	214/30a GLENLIVET, 214/30a REST	Glenlivet	Operator	30 November 2030 (anticipated)
P1453	206/4a UPPER, 206/4a LOWER, 206/4a REST	Edradour	Operator	31 March 2033 (anticipated)
P1453	206/4a BENRIACH	Benriach	Operator	31 March 2033 (anticipated)
P2411	206/5c, 214/30d	Edradour Royal Sovereign and Spinnaker	Operator	30 September 2044 (anticipated)
P2683	206/2a, 214/22a, 214/ 23a, 214/24a, 214/27, 214/28a, 214/29a	GLA Exploration — Ballechin, Cardhu, Sybil, Polly, Basil, Manuel, Caol-Ila, Vale T22	Operator	30 November 2049 (anticipated)
P2654	213/15b, 213/19, 213/ 20, 213/24b, 213/25, 213/29b, 213/30a, 214/ 11b, 214/16, 214/21	GLA Exploration — Kinclaith, Callanish Tri, Callanish Carb	Operator	28 February 2051 (initial term expiry)

Southern North Sea

P83	49/10a	Grove	Operator	— ⁽²⁾
P132	49/9a B	Grove	Operator	— ⁽²⁾
P468	49/4a Chiswick Area	Chiswick	Operator	— ⁽²⁾
P468	49/4a Kew Area	Kew	Operator	— ⁽²⁾
P1186	49/4b, 49/4c Chiswick Area	Chiswick	Operator	30 November 2030 (anticipated)
P1186	49/4c Kew Area, 49/5b, 49/5c	Kew	Operator	30 November 2030 (anticipated)
P455	49/5e North	Kew	Operator	— ⁽²⁾
P455	49/5a South	Markham	Operator	— ⁽²⁾
P30	47/8c F	Eris	Operator	— ⁽²⁾
P1060	47/3h	Eris	Operator	24 July 2028 (anticipated)
P1241	47/9c	Ceres	Operator	30 November 2030 (anticipated)
P8	48/19a B, 48/20a D	Clipper South	Non-operator	— ⁽²⁾
P465	48/19c F	Clipper South	Non-operator	— ⁽²⁾
P1909	48/20b	Clipper South	Non-operator	31 January 2038 (anticipated)
P130	48/15a REST	Galleon	Non-operator	— ⁽²⁾
P1055	44/11a, 44/12a	Cygnus	Non-operator	24 October 2030 (anticipated)
P1731	44/11b	Cygnus	Non-operator	30 April 2030 (anticipated)

Licence	Block(s)	Description	Role	Licence Expiry Date ⁽¹⁾
E-EMA-92079459	J3b, J6a (Markham)	Markham	Operator	N/A
E-EMA-92079459	J3b, J6a	J3C	Non-operator	N/A

Other Producing Assets

P1430	28/9a	Catcher	Non-operator	31 March 2033 (anticipated)
P101	23/21a Columbus	Columbus Development Area	Operator	— ⁽⁵⁾
P1314	23/16f	Columbus Development Area	Operator	21 December 2031
P57	23/26a Area B	Erskine Field – Production	Non-operator	— ⁽²⁾
P264	23/26b Area B	Erskine Field – Production	Non-operator	— ⁽⁵⁾
P264	23/26b Area C	Erskine Field – Production	Non-operator	— ⁽⁵⁾
P300	14/26a C	Golden Eagle Area Development	Non-operator	— ⁽⁵⁾
P928	20/1a North	Golden Eagle Area Development	Non-operator	24 July 2031 (anticipated)
P1606	3/3b	Orlando	Operator	11 February 2035 (anticipated)

Development and earlier-stage assets

P2170	20/5b, 21/1d	Greater Buchan Area	Non-operator	30 November 2040 (anticipated)
P2498	20/5a, 20/5e, 21/1a	Greater Buchan Area	Non-operator	29 August 2041 (anticipated)
P2400	30/12c, 30/13c, 30/17h, 30/18c	Skerryvore	Operator	30 September 2046 (anticipated)
P2634	14/15a, 14/20d, 15/11a	Fynn Beaully	N/A	28 February 2054 (anticipated)

Notes:

- (1) *Source:* Company internal analysis; NSTA Offshore Licence Data
- (2) Continues to cessation of production. Either: (a) following 2 consecutive calendar years where petroleum from the field in the Producing Area is below the minimum production level; or (b) where no minimum production level, following 2 consecutive calendar years where petroleum produced is zero; or (c) such period as the NSTA agrees in writing.
- (3) Either: (a) following 12 months where petroleum from the field in the producing area is below the minimum production level; (b) where no minimum production level, following 12 consecutive calendar months where petroleum produced is zero; or (c) such period as the NSTA agrees in writing; or (d) following a period of 12 months in which production has been continuously suspended as a result of sanctions imposed on Iran or Iranian nationals by the USA and/or EU.
- (4) Continues to cessation of production.
- (5) Continues to cessation of production. Either: (a) following 1 year where petroleum from the field in the producing area is below the minimum production level; or (b) where no minimum production level, following 1 year where petroleum produced is zero; or (c) such period as the NSTA agrees in writing.
- (6) Licence continues until Triton FPSO permanently ceases to (a) provide production and offloading services or (b) be located or anchored within the licensed area, subject to an OGA right to determine the licence earlier.
- (7) Production from the Lancaster field ceased on 3 May 2026.

11. LEGAL AND ARBITRATION PROCEEDINGS

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) covering at least the 12 months preceding the date of this document which may have, or have had, a significant effect on the financial position or profitability of the Company and/or the Group.

12. RELATED PARTY TRANSACTIONS

The Company has not entered into any related party transactions during the period from 30 June 2026 to the Latest Practicable Date, other than two liftings conducted pursuant to contracts that were put in place when Serica acquired Tailwind Energy Investments Ltd on 23 March 2023, principally the Offtake and Marketing Agreement covering oil offtake from Serica's share in the Triton area and part of Serica's share in Columbus.

13. PUBLIC TAKEOVER BIDS

13.1 City Code

The City Code applies to the Company and will, *inter alia*, regulate all transactions howsoever effected which have as their objective or potential effect (directly or indirectly) obtaining or consolidating control of the Company. Control for such purposes is defined as an interest or interests in shares carrying 30 per cent. or more of the voting rights of a company, irrespective of whether such interests give *de facto* control.

13.2 Mandatory Bids

Under the City Code, where:

- (a) any person acquires, whether by a series of transactions over a period of time or not, an interest in shares which (taken together with shares in which he is already interested, and in which persons acting in concert with him (as such expression is defined in the City Code) are interested) carry 30 per cent. or more of the voting rights of a company; or
- (b) any person, who together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30 per cent. of the voting rights of a company, but does not hold more than 50 per cent. of such voting rights and such person, or any person acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested, such person shall, except in limited circumstances, be obliged to extend offers, on the basis set out in Rules 9.3, 9.4 and 9.5 of the City Code, to the holders of any class of equity share capital whether voting or non-voting, and also to the holders of any other class of transferable securities carrying voting rights. Offers for different classes of equity share capital must be comparable.

13.3 Squeeze-out

Under sections 979 to 982 of the Act, if an offeror were to acquire 90 per cent. or more of the issued share capital of a company it could compulsorily acquire the remaining shares not already acquired by it. The offeror is required to serve notice on the outstanding shareholders informing them of its intention to compulsorily acquire the shares. No such notice may be served after the end of: (a) the period of three months beginning with the day after the last day on which the offer can be accepted; and (b) if earlier, and the offer is not one to which section 943(1) of the Act applies, the period of six months beginning with the date of the offer.

Six weeks following service of such notice, the offeror must send a copy of it to the Company together with the consideration for the issued share capital to which the notice relates, and an instrument of transfer executed on behalf of the outstanding shareholder(s) by a person authorised by the offeror. The Company will hold the consideration on trust for the outstanding shareholders.

13.4 Sell-out

Sections 983 to 985 of the Act also give minority shareholders in the Company a right to be bought out in certain circumstances by an offeror which has made a takeover offer. If the takeover offer related to all the issued ordinary shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90 per cent. of the issued ordinary shares, any holder of issued ordinary shares to which the offer related, who had not accepted the offer, could by

written communication to the offeror require it to acquire those shares. The offeror is required to give any shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or; if longer, a period of three months from the date of the notice. If a shareholder exercises his/her rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

13.5 Takeover bids

On 7 March 2025, the Company announced that it was in discussions with EnQuest plc (“**EnQuest**”) regarding a possible transaction to combine Serica and EnQuest, envisaged to be structured as an all-share offer by EnQuest for Serica. The announcement was issued following media speculation, pursuant to Rule 2.4 of the City Code. On 2 May 2025, EnQuest announced that, in light of market volatility, it was not possible to reach an agreement on terms, and confirmed that it did not intend to make a firm offer for Serica.

Save as described above, no public takeover bid has been made in respect of the Company’s equity during the last financial year or the current financial year.

14. CONSENT

ERC Equipoise Limited, of Eastbourne House, 2 Saxbys Lane, Lingfield, Surrey, RH7 6DN, has given and has not withdrawn its written consent to the inclusion in this document of the Sproule ERCE CPR set out in the Appendix (*Competent Person’s Report*) of this document, and the references thereto and to its name, and has authorised the contents of its report which is included in this document for the purposes of PRM 3.1.4R(2)(f) and item 1.3 of PRM App 2 Annex 3.1 and item 1.3 of PRM App 2 Annex 9.1.

15. MISCELLANEOUS

There are no conflicting interests that are material to Admission.

16. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents will be available for inspection during normal business hours on any weekday (Saturday, Sundays and public holidays excepted) at the offices of Serica Energy PLC, 72 Welbeck Street, London, W1G 0AY from the date of this document until at least 30 days after the date of Admission and will be available for viewing on the Company’s website at www.serica-energy.com (up to Admission):

- (a) the Articles;
- (b) the documents incorporated by reference into this document, as listed in Part 8 (*Documents Incorporated by Reference*) of this document;
- (c) the Sproule ERCE CPR contained in the Appendix (*Competent Person’s Report*) of this document; and
- (d) this document.

This document is dated 21 October 2026.

PART 8

DOCUMENTS INCORPORATED BY REFERENCE

The table below sets out the documents of which certain parts are incorporated by reference into, and form part of, this document. The parts of these documents which are not incorporated by reference are either not relevant for investors or are covered elsewhere in this document. To the extent that any information incorporated by reference itself incorporates any information by reference, either expressly or impliedly, such information will not form part of this document. Except as set forth below, no other portion of the below documents is incorporated by reference into this document.

Any statement contained in a document which is deemed to be incorporated by reference herein shall be deemed to be modified or superseded for the purposes of this document to the extent that a statement contained herein (or in a later document which is incorporated by reference herein) modifies or supersedes such earlier statement (whether expressly, by implication or otherwise).

The following documents are available for inspection in accordance with paragraph 16 of Part 7 (*Additional Information*) of this document.

<i>Reference Document</i>	<i>Information Incorporated by reference</i>	<i>Page number in the reference documents</i>
2025 Annual Report	Independent Auditors' Report to the members of Serica Energy plc	108-115
	Group Income Statement	116
	Group Statement of Comprehensive Income	117
	Group Balance Sheet	118
	Group Statement of Changes in Equity	119
	Group Cash Flow Statement	120
	Notes to the Financial Statements	121-161
	Company Balance Sheet	163
	Company Statement of Changes in Equity	164
	Notes to the Company Financial Statements	165-168
	Reconciliation of Non-IFRS Measures	169-170
2026 Interim Results	Condensed Consolidated Statement of Profit or Loss	18
	Condensed Consolidated Statement Comprehensive Income	19
	Condensed Consolidated Statement of Financial Position	20
	Condensed Consolidated Statement of Changes in Equity	21
	Condensed Consolidated Cash Flow Statement	22
	Notes to the Condensed Consolidated Financial Statements	23-41
	Reconciliation of Non-IFRS Measures	42-43

PART 9

TECHNICAL TERMS

The following glossary of technical terms applies throughout this document unless the context requires otherwise:

Term	Meaning
“2C”	the best estimate of contingent resources;
“2P”	proved plus probable reserves;
“bbl”	barrel of 42 US gallons;
“boe”	barrel of oil equivalent;
“boepd”	barrels of oil equivalent per day;
“CO ₂ ”	carbon dioxide;
“CO ₂ e”	carbon dioxide equivalent;
“contingent resources”	contingent resources are those quantities of petroleum which are estimated 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;
“FEED”	Front-End Engineering Design;
“FPSO”	floating production storage and offloading;
“kboepd”	thousand barrels of oil equivalent per day;
“mmboe”	million barrels of oil equivalent;
“NGLs”	natural gas liquids extracted from gas streams;
“P50”	the best estimate of prospective resources;
“possible reserves”	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 + probable + possible reserves;
“PRMS”	the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers, as amended;
“probable reserves”	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 + probable reserves;
“prospective resources”	prospective resources are those quantities of petroleum which are estimated to be potentially recoverable from undiscovered accumulations by application of future projects. Prospective resources have both an associated chance of discovery and a chance of development;
“proved reserves”	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;
“p/th”	pence/therm;
“Reserves”	estimates of discovered recoverable commercial hydrocarbon reserves; and
“stb/d”	stock tank barrels per day.

PART 10

DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

“2025 Annual Report”	the annual report and accounts of the Group for the year ended 31 December 2025;
“2026 Interim Results”	the unaudited interim results of the Group for six months ended 30 June 2026;
“‘A’ Share”	the ‘A’ Share of £50,000 in the capital of the Company;
“Admission”	admission of the Ordinary Shares (i) to the equity shares (commercial companies) category of the Official List and (ii) to trading on the London Stock Exchange’s Main Market;
“AIM”	AIM, a market operated by the London Stock Exchange;
“Amended Relationship Agreement”	the relationship agreement between the Company and Mercuria, as amended and restated pursuant to an amendment and restatement agreement dated 21 October 2026, a summary of which is set out at paragraph 9.4 of Part 7 (<i>Additional Information</i>) of this document;
“Articles”	the articles of association of the Company as at the date of this document, a summary of certain provisions of which is set out in paragraph 4 of Part 7 (<i>Additional Information</i>);
“BKR”	the Bruce, Keith and Rhum fields;
“Board” or “Directors”	the board of directors of the Company as at the date of this document;
“BP”	BP Exploration Operating Company Limited;
“Bruce Hub”	the Bruce hub which comprises the Bruce, Keith and Rhum fields which feed into the Bruce Platform;
“certificated” or “in certificated form”	the description of a share or other security which is not in uncertificated form (that is, not in CREST);
“City Code”	the City Code on Takeovers and Mergers in the United Kingdom;
“Companies Act”	the Companies Act 2006, as amended;
“Company” or “Serica”	Serica Energy plc, a company incorporated in England and Wales with registration number 5450950;
“Corporate Governance Code”	the UK Corporate Governance Code, published by the Financial Reporting Council;
“CREST”	the computerised settlement system, facilitating the paperless settlement of trades and the holding of uncertificated shares administered by Euroclear UK & International Limited, the operator of CREST;
“CREST Regulations”	the Uncertificated Securities Regulations 2001 of the UK (SI 2001/3755) (as amended);
“DTRs” or “Disclosure Guidance and Transparency Rules”	the disclosure guidance and transparency rules of the FCA made pursuant to Part VI of FSMA;
“EPL”	the energy profits levy;
“ERSS”	Edradour Royal Sovereign and Spinnaker (formerly referred to as Glendronach);
“EU”	the European Union;
“FCA”	the United Kingdom Financial Conduct Authority;

“FSMA”	the UK Financial Services and Markets Act 2000 (as amended) including any regulations made pursuant thereto;
“FY 2024”	the financial year ended 31 December 2024;
“FY 2025”	the financial year ended 31 December 2025;
“FY 2026”	the financial year ending 31 December 2026;
“FY 2026 Post-Tax CFFO Guidance”	has the meaning given in Section B of Part 3 (<i>Selected Financial Information</i>) of this document;
“GLA Assets”	a 40 per cent. interest in each of the Laggan, Tormore, Glenlivet, Edradour and ERSS fields and the onshore Shetland Gas Plant;
“Group”	the Company and its subsidiaries as at the date of this document;
“HMRC”	His Majesty’s Revenue and Customs;
“HSE”	health, safety and environment;
“HY 2025”	the six-month period ended 30 June 2025;
“HY 2026”	the six-month period ended 30 June 2026;
“IFRS”	UK-adopted International Financial Reporting Standards;
“IOC”	Iranian Oil Company (UK) Limited, Serica UK’s partner on the Rhum field;
“ISIN”	International Securities Identification Number
“JCPOA”	the Joint Comprehensive Plan of Action, the 2015 international agreement to provide sanctions relief to Iran in return for restrictions on Iran’s nuclear programme;
“Latest Practicable Date”	19 October 2026, being the latest practicable date prior to publication of this document;
“LEI”	Legal Entity Identifier;
“London Stock Exchange”	London Stock Exchange plc;
“Main Market”	the main market for listed securities of London Stock Exchange;
“Mercuria”	Mercuria Holdings (UK) Limited, a company incorporated in England and Wales with registered number 12371828;
“NICO”	Naftiran Intertrade Co. (NICO) Limited;
“NIOC”	National Iranian Oil Company;
“Nordic Bond”	the 5-year \$300 million senior unsecured bonds issued by the Company, a summary of which is set out in paragraph 9.3 of Part 7 (<i>Additional Information</i>) of this document;
“NSTA”	North Sea Transition Authority;
“OFAC”	US Office of Foreign Asset Control;
“OFAC License”	a licence from OFAC permitting specified US entities and non-US entities owned or controlled by US persons to deal with IOC;
“Official List”	the Official List of the FCA;
“ONE-Dyas Asset Acquisition”	the acquisition of certain interests in the Catcher oil field and the Golden Eagle Area Development from ONE-Dyas UK Limited;
“ONE-Dyas”	ONE-Dyas UK Limited;
“Option Deed”	the put and call option deed dated 28 March 2025 between Prax Hurricane GLA Limited and ONE-Dyas relating to the ONE-Dyas Asset Acquisition, a summary of which is set out in paragraph 9.12 of Part 7 (<i>Additional Information</i>) of this document;

“OPRED”	the Offshore Petroleum Regulator for Environment and Decommissioning;
“Ordinary Shares”	the ordinary shares of \$0.10 each in the capital of the Company;
“Peel Hunt” or “Sponsor”	Peel Hunt LLP;
“POATRs”	the Public Offers and Admissions to Trading Regulations 2024;
“Prax Upstream”	Prax Upstream Limited;
“Prax Upstream Acquisition”	the acquisition of Prax Upstream by Serica;
“Prax Upstream SPA”	the sale and purchase agreement dated 29 September 2025 between Serica and Prax Exploration & Production plc (in Administration) and its joint administrators, a summary of which is set out in paragraph 9.10 of Part 7 (<i>Additional Information</i>) of this document;
“PRM”	the Prospectus Rules: Admission to Trading on a Regulated Market sourcebook of the FCA;
“Q3 2026”	the three-month period ended 30 September 2026;
“Q3 2026 Trading Update”	the announcement published by the Company on 19 September 2026 providing a trading and operational update in respect of Q3 2026 and the first nine months of 2026;
“RBL Facility”	the Group’s reserves-based lending facility with, among others, Deutsche Bank AG, Amsterdam Branch, DNB (UK) Limited, ICBC Standard Bank plc, ING Bank N.V., Macquarie Bank Limited, London Branch, Natixis, London Branch and Nedbank Limited, London Branch as lenders pursuant to the facility agreement dated 22 July 2026, a summary of which is set out at paragraph 9.2 of Part 7 (<i>Additional Information</i>) of this document;
“Serica Energy Investments”	Serica Energy Investments Limited, formerly Tailwind Energy Investments Limited;
“Serica UK”	Serica Energy (UK) Limited, a wholly-owned subsidiary of the Company;
“Shareholders”	holders of Ordinary Shares from time to time;
“SPE”	the Society of Petroleum Engineers;
“Spirit Energy Portfolio Acquisition”	the acquisition by Serica of a portfolio of Southern North Sea assets from Spirit Energy Limited and affiliates pursuant to the Spirit Energy Portfolio SPA;
“Spirit Energy Portfolio SPA”	the sale and purchase agreement dated 16 December 2025 between Prax Hurricane GWA Limited, Prax Hurricane (Whirlwind) Limited, Spirit Energy Limited and certain of its affiliates relating to the Spirit Energy Portfolio Acquisition, a summary of which is set out in paragraph 9.13 of Part 7 (<i>Additional Information</i>) of this document;
“Sponsor Agreement”	the sponsor agreement between Peel Hunt and the Company dated 21 October 2026, a summary of which is set out at paragraph 9.1 of Part 7 (<i>Additional Information</i>) of this document;
“Sproule ERCE”	ERC Equipoise Limited;
“Sproule ERCE CPR”	the competent person’s report relating to certain assets acquired by the Group pursuant to acquisitions that completed in 2026 (namely, the TTE Asset Acquisition, the ONE-Dyas Asset Acquisition and the Spirit Energy Portfolio Acquisition) prepared by Sproule ERCE, as set out in the Appendix (<i>Competent Person’s Report</i>) of this document;
“Tailwind Acquisition”	the acquisition by Serica of the entire issued share capital of Serica Energy Investments Limited (formerly, Tailwind Energy Investments

	Limited) from Tailwind Energy Holding LLP pursuant to the Tailwind Acquisition Agreement;
“Tailwind Acquisition Agreement”	the share purchase agreement dated 20 December 2022 between Company and Tailwind Energy Holdings LLP, a summary of which is set out at paragraph 9.6 of Part 7 (<i>Additional Information</i>) of this document;
“Total E&P”	Total E&P UK Limited or TotalEnergies E&P UK Limited (now known as NEO NEXT+ Energy E&P UK Limited);
“TTE APA”	a deed of amendment and restatement dated 29 September 2025 entered into between the Company, Prax Upstream and certain of its subsidiaries and Total E&P in relation to a sale and purchase agreement relating to interests in the Greater Laggan Area and Shetland Gas Plant, a summary of which is set out in paragraph 9.11 of Part 7 (<i>Additional Information</i>) of this document;
“TTE Asset Acquisition”	the acquisition from Total E&P of the GLA Assets and four near field exploration blocks;
“Triton” or “Triton Hub”	the operated and non-operated fields tied back to the Triton FPSO;
“UK IAS”	UK-adopted International Accounting Standards;
“UK Listing Rules” or “UKLR”	the UK Listing Rules Sourcebook of the FCA made under Part VI of the FSMA;
“UK MAR”	the version of Regulation (EU) No 596/2014 of the European Parliament and of the Council of 16 April 2014 on market abuse as it forms part of the domestic law of the UK by virtue of the European Union (Withdrawal) Act 2018 (as amended);
“uncertificated” or “uncertificated form”	recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which may be transferred by means of CREST;
“UKCS”	the UK Continental Shelf;
“United Kingdom” or “UK”	the United Kingdom of Great Britain and Northern Ireland;
“US Securities Act”	the United States Securities Acts of 1933, as amended, and the rules and regulations promulgated thereunder;
“\$” or “US dollar” or “USD”	the US dollar, the lawful currency from time to time of the United States; and
“£” or “pounds sterling”	pounds sterling, the lawful currency from time to time of the United Kingdom.

APPENDIX
COMPETENT PERSON'S REPORT

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

Digital Report Notification

This report has been prepared in a fully digital, auditable, and legally compliant format using a PDF/A standard (ISO 19005-1, 2 or 3).

Sproule ERCE professionals have also signed the report using independently verifiable digital signatures for authentication purposes. For more information regarding digital reports, digital signatures, and their verification, please visit [Sproule ERCE Digital Signatures](#).

Prepared For	Serica Energy (UK) Limited
Project Number	Client 37225, Project 117403
Distribution	Serica Energy (UK) Limited
	Summary Volume (Digital copy)
	Sproule ERCE (Full digital copy retained)
Editor	MC

This document is strictly confidential and solely for the recipient's use and may not be reproduced or circulated without Sproule ERCE's prior written consent. If you are not the intended recipient, you may not disclose or use the information in this documentation in any way.

Table of Contents

1.Executive Summary	13
1.1 Asset Overview and Highlights	14
1.2 Reserves	21
1.3 Contingent Resources	28
2.Introduction	32
2.1 Data Provided	33
2.2 Work Completed	34
3.Greater Laggan Area	36
3.1 Development Plans	42
3.2 Estimated Ultimate Recovery.....	43
3.3 Facilities and Cost.....	44
3.4 Reserves	46
3.5 Contingent Resources	46
4.Catcher Area	51
4.1 Development Plans	59
4.2 Estimated Ultimate Recovery.....	59
4.3 Facilities and Costs	62
4.4 Reserves	64
4.5 Contingent Resources	64
5.Golden Eagle Area Development	68
5.1 Development Plans	71
5.2 Estimated Ultimate Recovery.....	71
5.3 Facilities and Cost.....	72
5.4 Reserves	73
5.5 Contingent Resources	73
6.Greater Markham Area	76

6.1	Development Plans	83
6.2	Estimated Ultimate Recovery.....	83
6.3	Facilities and Cost.....	85
6.4	Reserves	86
6.5	Contingent Resources	87
7.	Cygnus Field	90
7.1	Development Plans	92
7.2	Estimated Ultimate Recovery.....	93
7.3	Facilities and Costs	98
7.4	Reserves	99
7.5	Contingent Resources	99
8.	Clipper South Field	101
8.1	Development Plans	103
8.2	Estimated Ultimate Recovery.....	103
8.3	Facilities and Cost.....	105
8.4	Reserves	106
8.5	Contingent Resources	106
9.	Galleon Field	108
9.1	Development Plans	110
9.2	Estimated Ultimate Recovery.....	111
9.3	Facilities and Cost.....	112
9.4	Reserves	113
9.5	Contingent Resources	113
10.	Eris Field	114
10.1	Development Plans	116
10.2	Estimated Ultimate Recovery	116
10.3	Facilities and Cost	118

10.4	Reserves.....	118
10.5	Contingent Resources	118
11.	Economic Evaluation	119
11.1	Petroleum Fiscal Terms.....	119
11.2	Commercial Assumptions	119
11.3	Commodity Price and Carbon Allowance	120
11.4	Net Present Values.....	121
	Appendix 1: Gross Production and Cost Forecasts	123
	Appendix 2: Reserves and Resource Definitions	141
	Appendix 3: Nomenclature	150

Tables

Table 1.1: Summary of Licence Interests	13
Table 1.2: Developed Reserves as at 30 June 2026	22
Table 1.3: Undeveloped Reserves as at 30 June 2026	23
Table 1.4: Total Reserves as at 30 June 2026	24
Table 1.5: Hydrocarbon price forecasts as at 30 June 2026	25
Table 1.6: Asset level CoP dates	26
Table 1.7: Asset level before tax NPV of the total Reserves	27
Table 1.8: Corporate entity level before and after tax NPV of the total Reserves	28
Table 1.9: Oil Contingent Resources as at 30 June 2026	29
Table 1.10: Gas Contingent Resources as at 30 June 2026	30
Table 1.11: Oil Equivalent Contingent Resources as at 30 June 2026	30
Table 3.1: GLA EUR estimates and recovery factors	43
Table 3.2: GLA production efficiency forecast	44
Table 3.3: GLA gross Reserves with CoP dates	46
Table 3.4: GLA gross Contingent Resources	50
Table 4.1: Catcher Area EUR estimates and recovery factors	61
Table 4.2: Catcher field production efficiency forecast	61
Table 4.3: Catcher Area gross Reserves with CoP dates	64
Table 4.4: Summary of gross Contingent Resources in the Catcher Area	67
Table 5.1: GEAD Area EUR estimates and recovery factors	71
Table 5.2: GEAD production efficiency forecast	71
Table 5.3: Golden Eagle Area gross Reserves with CoP dates	73
Table 5.4: Summary of gross Contingent Resources in GEAD area	75
Table 6.1: GMA EUR estimates and recovery factors	84
Table 6.2: GMA production efficiency forecast	84
Table 6.3: GMA gross Reserves with CoP dates	87
Table 6.4: Summary of gross Contingent Resources in the GMA area	89

Table 7.1: Dynamic GIIP estimates from production data	93
Table 7.2: Cygnus EUR estimates and recovery factors	96
Table 7.3: Cygnus production efficiency forecast	97
Table 7.4: Cygnus Field gross Reserves with CoP dates	99
Table 7.5: Summary of gross Contingent Resources in the Cygnus Field	100
Table 8.1: Clipper South Field EUR estimates and recovery factors	104
Table 8.2: Clipper South production efficiency forecast.....	104
Table 8.3: Clipper South Field gross Reserves with CoP dates	106
Table 8.4: Summary of gross Contingent Resources in the Clipper South area	107
Table 9.1: Galleon field EUR estimates and recovery factors.....	111
Table 9.2: Galleon production efficiency forecast.....	111
Table 9.3: Galleon Field gross Reserves with CoP dates.....	113
Table 10.1: Eris field EUR estimates and recovery factors.....	117
Table 10.2: Summary of gross Contingent Resources in the Eris Field	118
Table 11.1: Sproule ERCE Commodity Price Forecasts as at 30 June 2026	120
Table 11.2: Asset level before tax net NPV of the total Reserves	121

Appendix 1 Tables

Table A - 1: GLA 1P gross developed production and cost forecasts	123
Table A - 2: GLA 2P gross developed production and cost forecasts	123
Table A - 3: GLA 3P gross developed production and cost forecasts	124
Table A - 4: Catcher 1P gross developed production and cost forecasts	124
Table A - 5: Catcher 2P gross developed production and cost forecasts	125
Table A - 6: Catcher 3P gross developed production and cost forecasts	125
Table A - 7: GEAD 1P gross developed production and cost forecasts	126
Table A - 8: GEAD 2P gross developed production and cost forecasts	127
Table A - 9: GEAD 3P gross developed production and cost forecasts	128
Table A - 10: Chiswick 1P gross developed production and cost forecasts	128

Table A - 11: Chiswick 2P gross developed production and cost forecasts	129
Table A - 12: Chiswick 3P gross developed production and cost forecasts	129
Table A - 13: Grove 1P gross developed production and cost forecasts	129
Table A - 14: Grove 2P gross developed production and cost forecasts	130
Table A - 15: Grove 3P gross developed production and cost forecasts	130
Table A - 16: Kew 1P gross developed production and cost forecasts	130
Table A - 17: Kew 2P gross developed production and cost forecasts	131
Table A - 18: Kew 3P gross developed production and cost forecasts	131
Table A - 19: J3C 1P gross developed production and cost forecasts	131
Table A - 20: J3C 2P gross developed production and cost forecasts	132
Table A - 21: J3C 3P gross developed production and cost forecasts	132
Table A - 22: Cygnus 1P gross developed production and cost forecasts	133
Table A - 23: Cygnus 2P gross developed production and cost forecasts	133
Table A - 24: Cygnus 3P gross developed production and cost forecasts	134
Table A - 25: Cygnus 1P gross developed plus undeveloped production and cost forecasts	135
Table A - 26: Cygnus 2P gross developed plus undeveloped production and cost forecasts	135
Table A - 27: Cygnus 3P gross developed plus undeveloped production and cost forecasts	136
Table A - 28: Clipper South 1P gross developed production and cost forecasts	137
Table A - 29: Clipper South 2P gross developed production and cost forecasts	137
Table A - 30: Clipper South 3P gross developed production and cost forecasts	138
Table A - 31: Galleon 1P gross developed production and cost forecasts	138
Table A - 32: Galleon 2P gross developed production and cost forecasts	139
Table A - 33: Galleon 3P gross developed production and cost forecasts	139
Table A - 34: Eris 1P gross developed production and cost forecasts	140
Table A - 35: Eris 2P gross developed production and cost forecasts	140
Table A - 36: Eris 3P gross developed production and cost forecasts	140

Figures

Figure 2.1: Asset areas of interest	32
---	----

Figure 3.1: GLA fields location map.....	36
Figure 3.2: GLA hub wet gas production and CGR history	37
Figure 3.3: GLA hub wet gas production and CGR history, 2025+	38
Figure 3.4: Laggan Field amplitude extent and mapped faults	39
Figure 3.5: Tormore Field top structure map	40
Figure 3.6: Glenlivet Field top structure map.....	41
Figure 3.7: Edradour Field depth structure map	42
Figure 3.8: GLA gross wellhead gas production forecasts	44
Figure 3.9: ERSS discovery top structure map of primary and secondary targets	47
Figure 3.10: Assessed Tormore infill location with Sproule ERCE low and high case areas	49
Figure 4.1: Overview of blocks, Catcher Area	51
Figure 4.2: Catcher field Top Cromarty and Top Tay depth structure maps	53
Figure 4.3: Varadero field Top Tay depth structure maps	54
Figure 4.4: Burgman field Top Cromarty depth structure maps	55
Figure 4.5: Catcher Field production and injection history	56
Figure 4.6: Varadero Field production and injection history.....	57
Figure 4.7: Burgman Field production and injection history.....	58
Figure 4.8: Catcher Area gross wellhead oil production forecasts	62
Figure 4.9: Catcher Area development schematic.....	63
Figure 4.10: NE-SW seismic cross section from Varadero Main to Varadero West.....	65
Figure 4.11: N-S seismic cross section through Burgman North (left) and Burgman SNA map (right) ..	66
Figure 5.1: Overview of licences, GEAD	68
Figure 5.2: GEAD Top Punt depth structure map	69
Figure 5.3: GEAD Fields production and injection history	70
Figure 5.4: GEAD gross wellhead oil production forecasts.....	72
Figure 5.5: Locations of opportunities in Punt 2E and 2F reservoirs.....	74
Figure 6.1: Overview of licensed blocks, Greater Markham Area	76
Figure 6.2: GMA gas production history, by field.....	78

Figure 6.3: GMA daily gas production history, by well (2025 to 30 June 2026)	78
Figure 6.4: Chiswick field top structure map.....	79
Figure 6.5: Kew field top structure map.....	80
Figure 6.6: Grove field top structure map.....	81
Figure 6.7: J3-C Field top structure map.....	82
Figure 6.8: GMA gross wellhead gas production forecasts	85
Figure 6.9: Grove East Area and planned well location.....	88
Figure 7.1: Cygnus Field location map.....	90
Figure 7.2: Cygnus top Lemman depth structure map	91
Figure 7.3: Cygnus Field production history	92
Figure 7.4: Approximate location of infill Well FB4 (14 th Well)	95
Figure 7.5: Approximate location of infill Well FB5 (15 th Well)	96
Figure 7.6: Cygnus developed gross wellhead gas production forecasts	97
Figure 7.7: Cygnus developed plus undeveloped gross wellhead gas production forecasts.....	98
Figure 7.8: Approximate location of infill Well FB8 (16 th Well)	100
Figure 8.1: Location map of Clipper South gas Field.....	101
Figure 8.2: Clipper South top structure map.....	102
Figure 8.3: Clipper South field production history.....	103
Figure 8.4: Clipper South gross wellhead gas production forecasts	105
Figure 8.5: NW Clipper South area and proposed 5th well region.....	107
Figure 9.1: Galleon field location map.....	108
Figure 9.2: Galleon Field gas production history	110
Figure 9.3: Galleon gross wellhead gas production forecasts	112
Figure 10.1: Eris field location map.....	114
Figure 10.2: Eris Field top structure map	115
Figure 10.3: Eris Field production history.....	116
Figure 10.4: Eris gross wellhead gas production forecasts	117

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.

This document may not be reproduced, excerpted, distributed or modified without Sproule ERCE's prior written consent and all content must be presented in its entirety. If delivered in digital format, Sproule ERCE disclaims any responsibility for any changes or modifications made by the Client or any third party, after delivery.

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:

- 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).

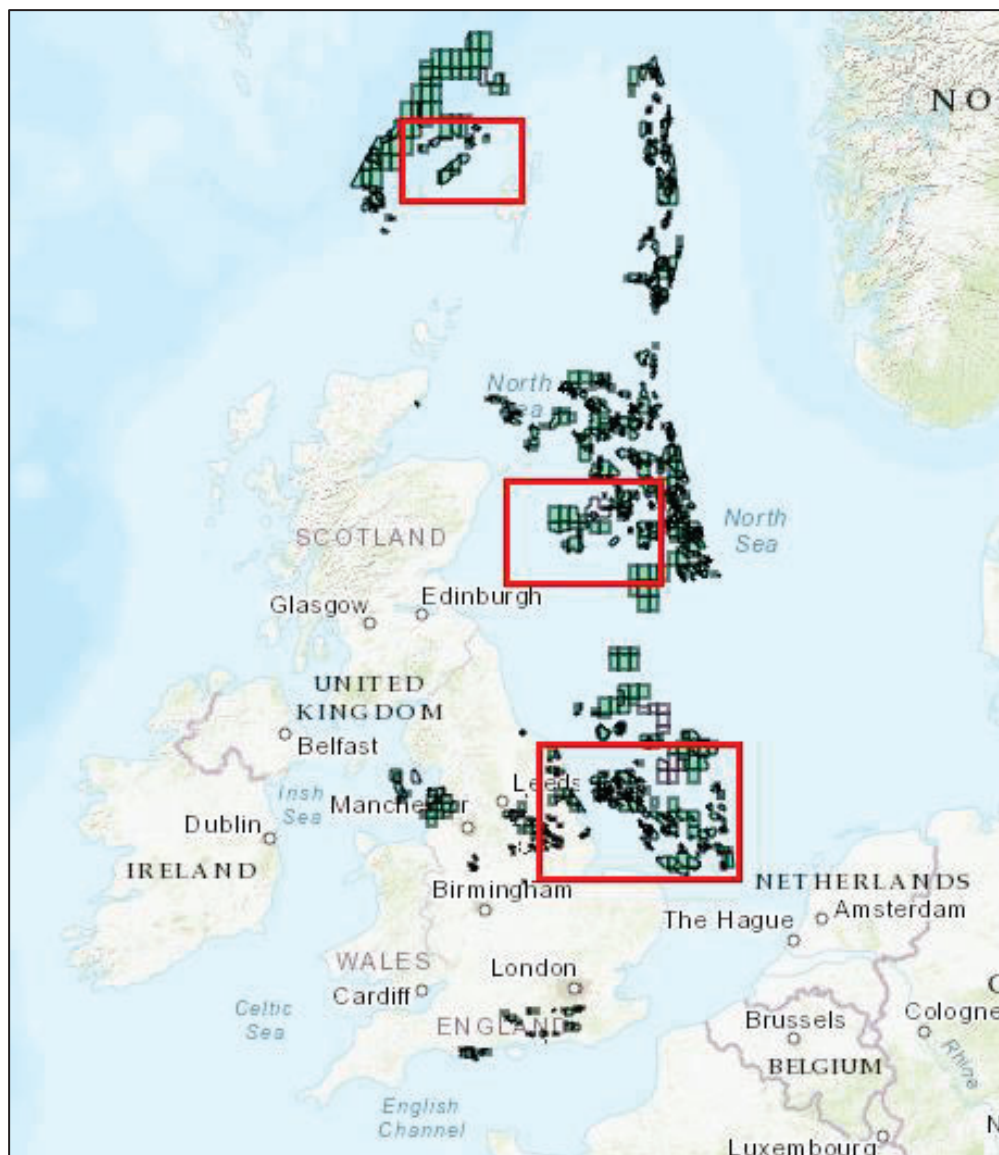


Figure 2.1: Asset areas of interest

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 tieing-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.

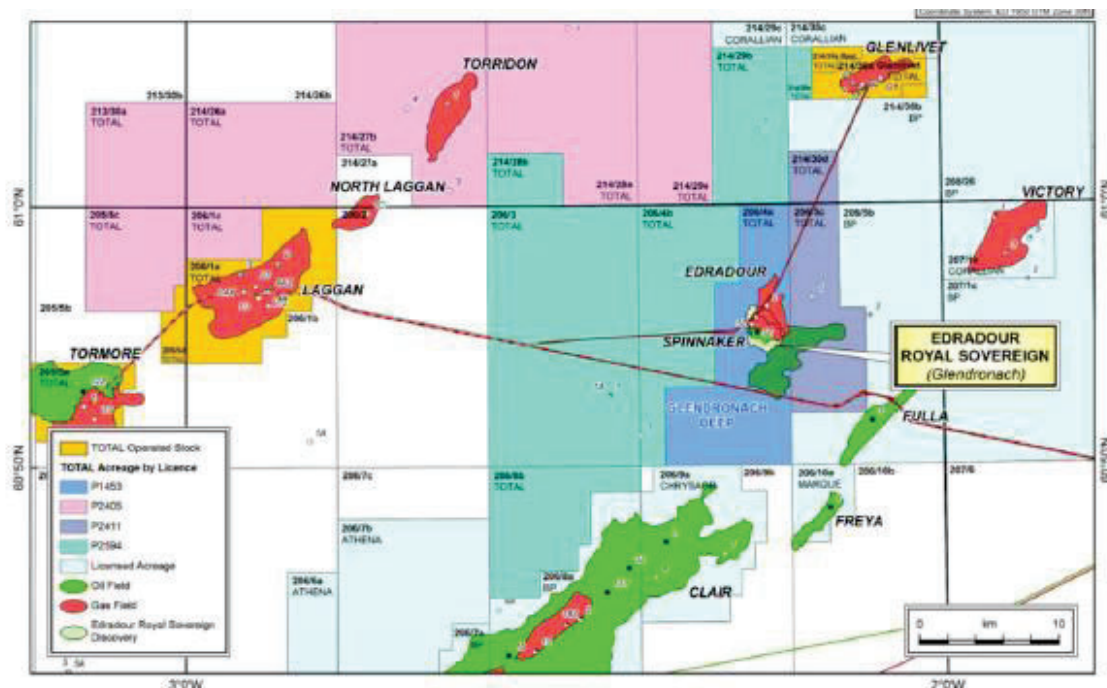


Figure 3.1: GLA fields location map

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”.

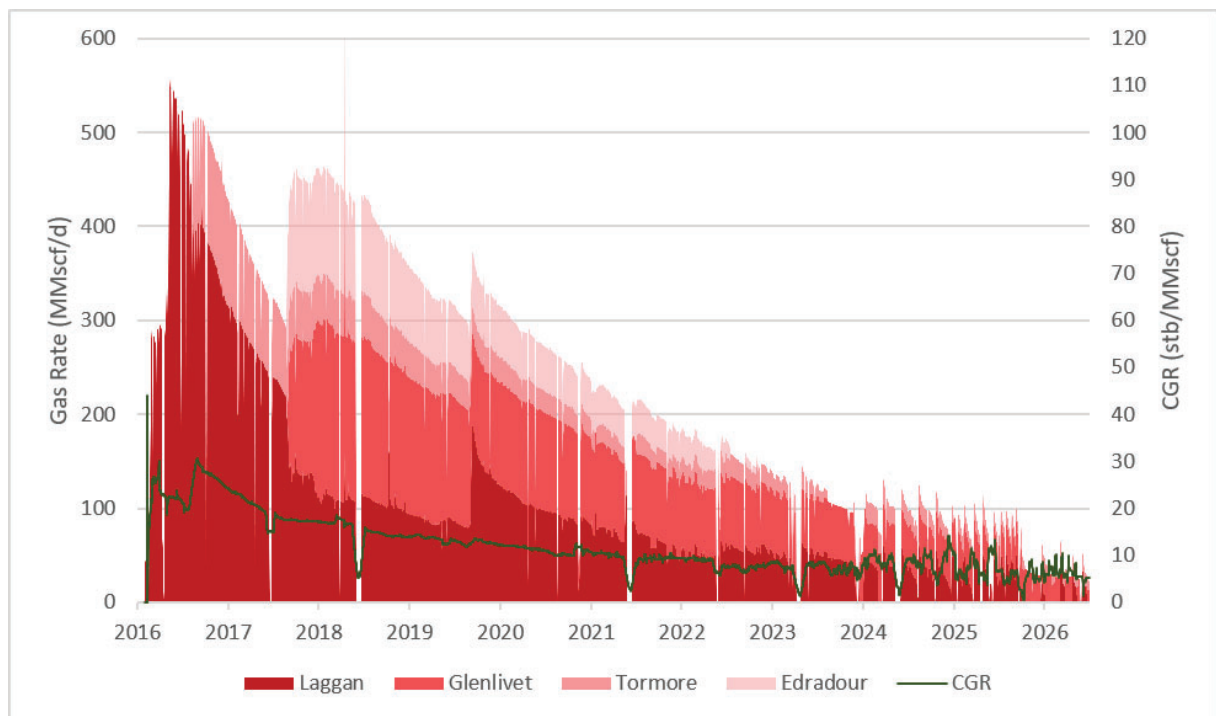


Figure 3.2: GLA hub wet gas production and CGR history

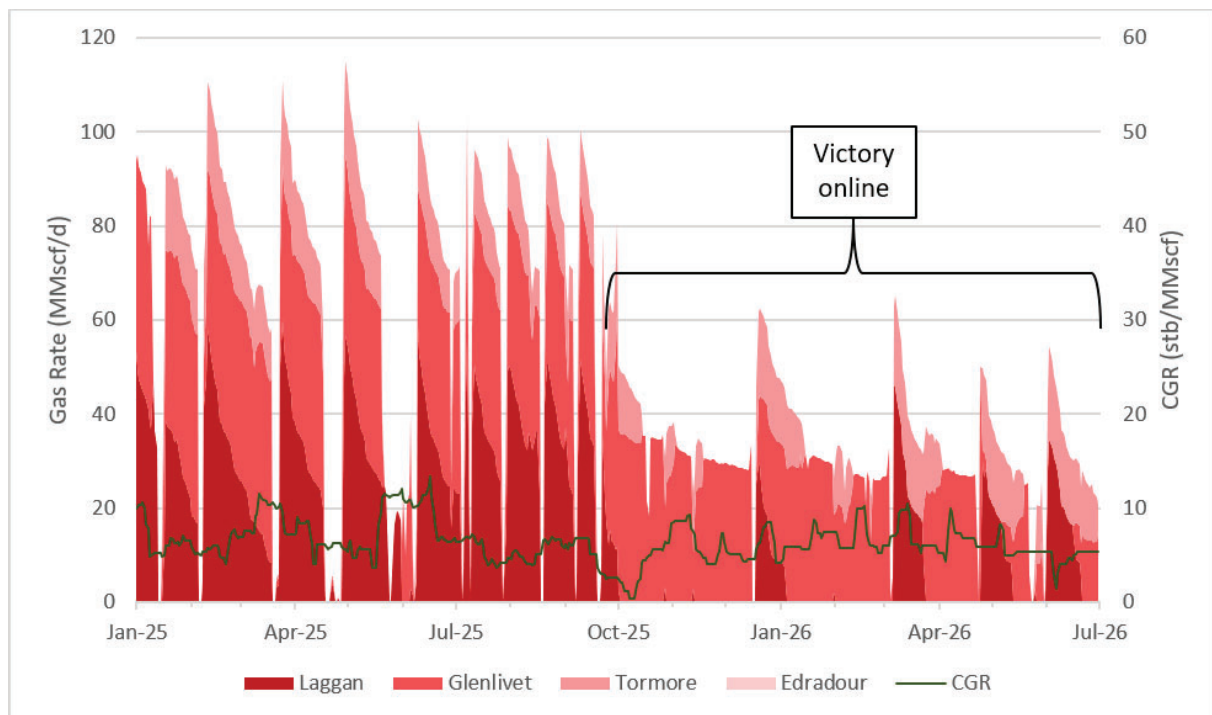


Figure 3.3: GLA hub wet gas production and CGR history, 2025+

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%.

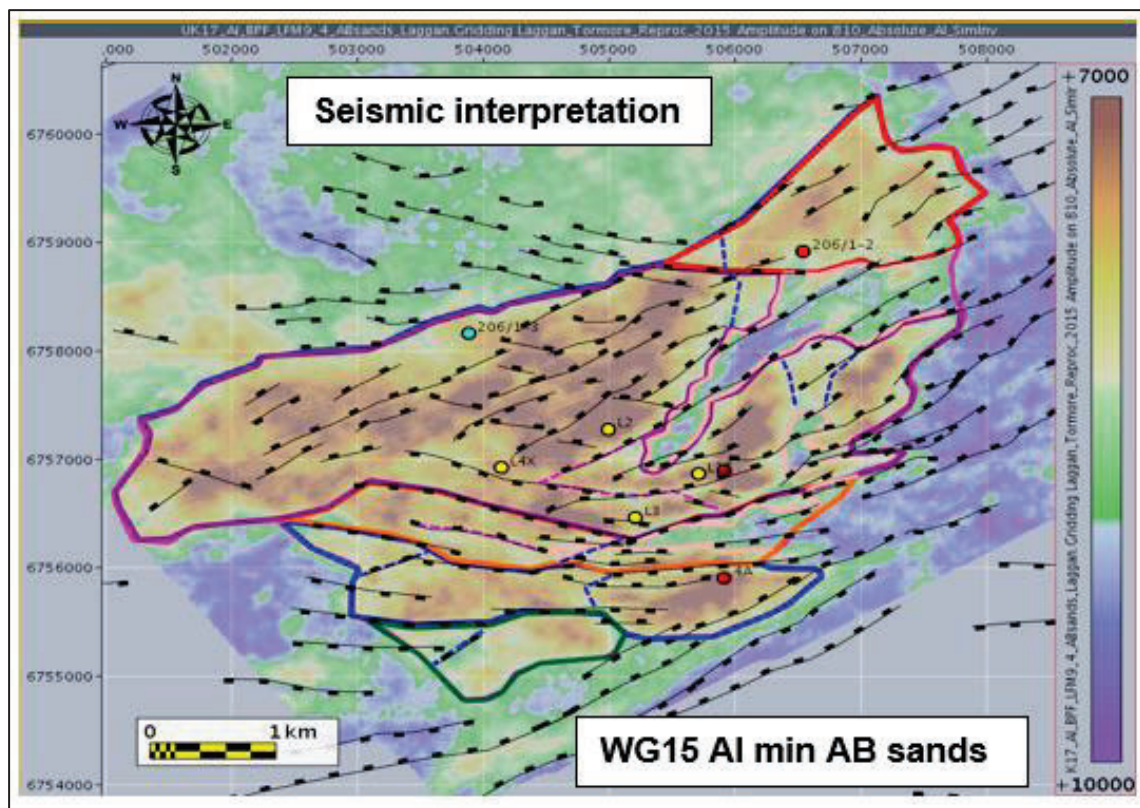


Figure 3.4: Laggan Field amplitude extent and mapped faults

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

90%, with porosities averaging 23%. The field was developed by a single well, Well T3, drilled in the crest of the reservoir

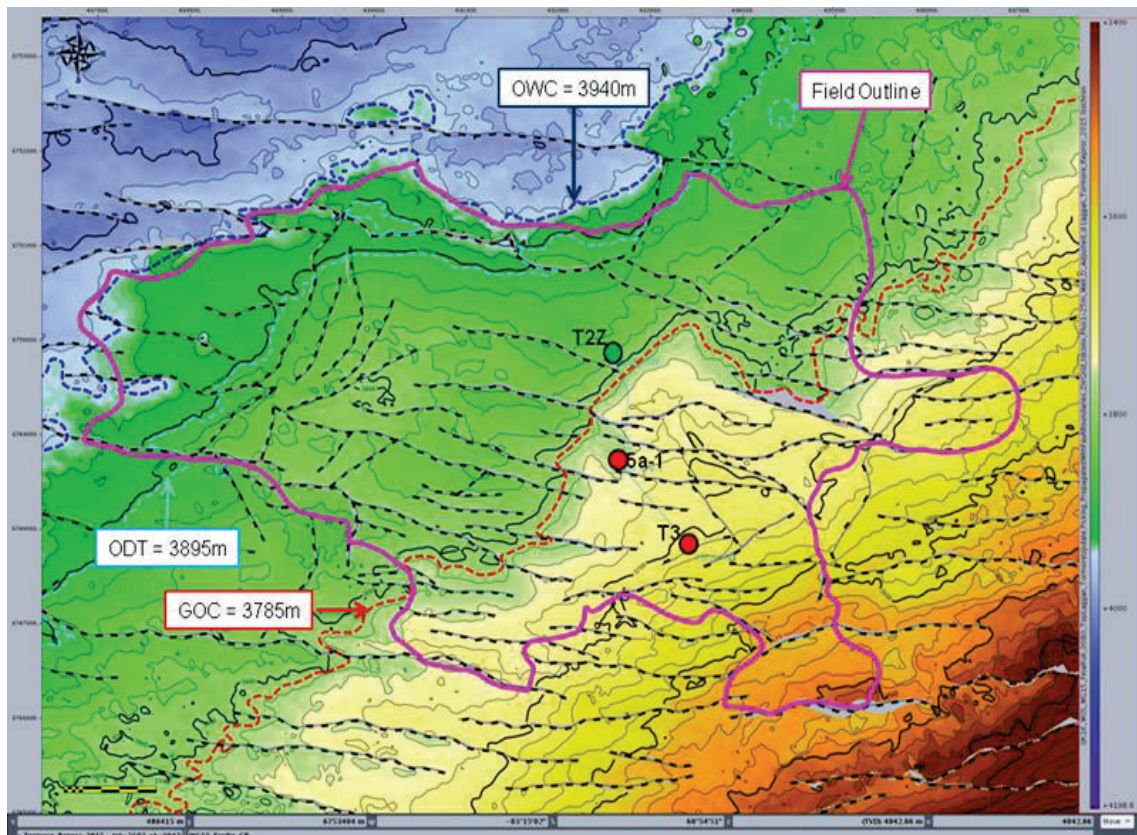


Figure 3.5: Tormore Field top structure map

Source: Operator

First gas was achieved in Q3 2016. As in the Laggan Field, performance has been severely impacted by the Victory tie-back, with Well T3 only available for short flow periods following shut-ins. Cumulative gas production up to 30 June 2026 was 104 Bscf.

Glenlivet Field

The Glenlivet field is located approximately 45 km north-east of Laggan in 430 m water depth in Block 214/30a. The field was discovered in 2009 after Well 214/30a-2 encountered a 65 m thick gas column. The reservoir in Glenlivet consists of Palaeocene turbidite sandstones of the Vaila Formation. The reservoir is limited to the south-east by a stratigraphic pinch-out and to the north-west by underlying Cretaceous shales and faulting (Figure 3.6). Limited faulting is observed on the supplied reservoir maps. The reservoirs are of good porosity (27%) and high NTG (95%). The permeability ranges from 40 to 120 mD.

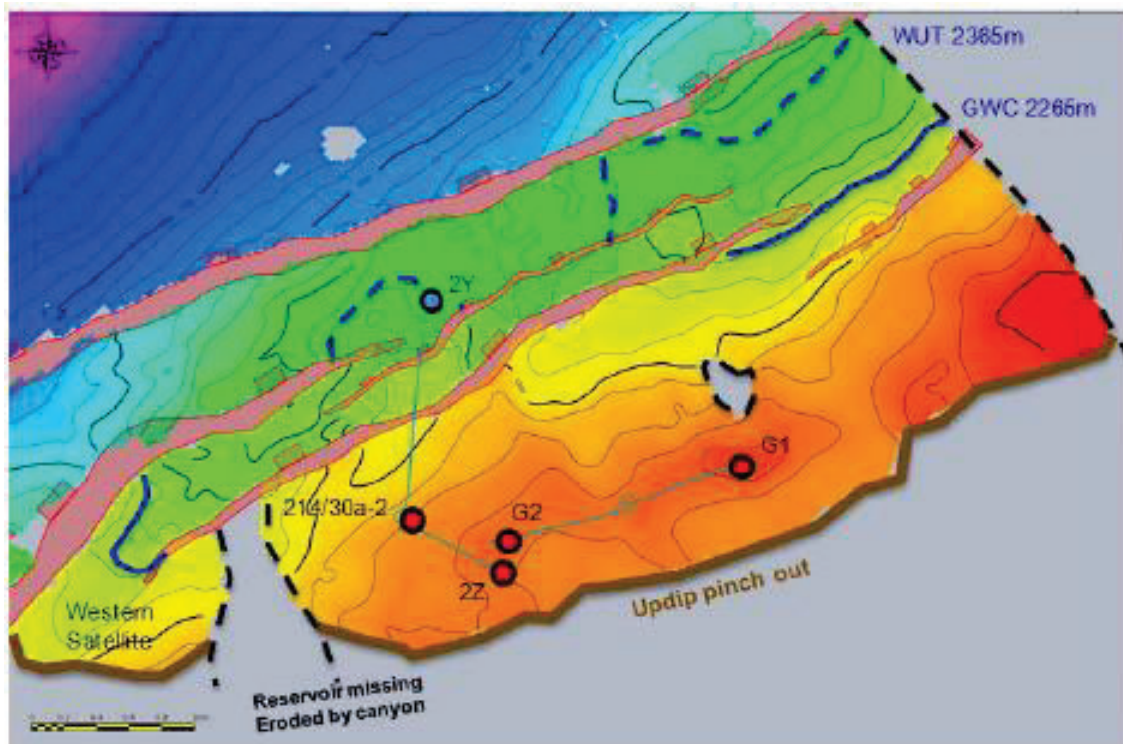


Figure 3.6: Glenlivet Field top structure map

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%).

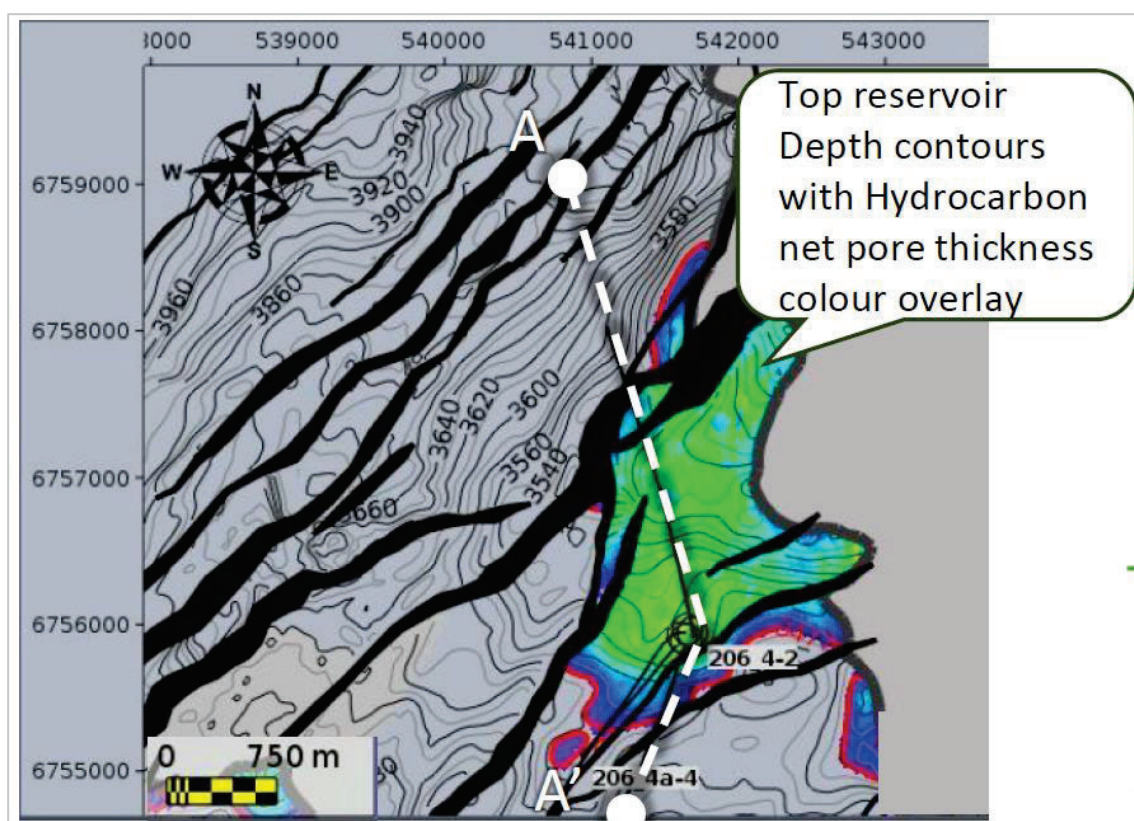


Figure 3.7: Edradour Field depth structure map

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.

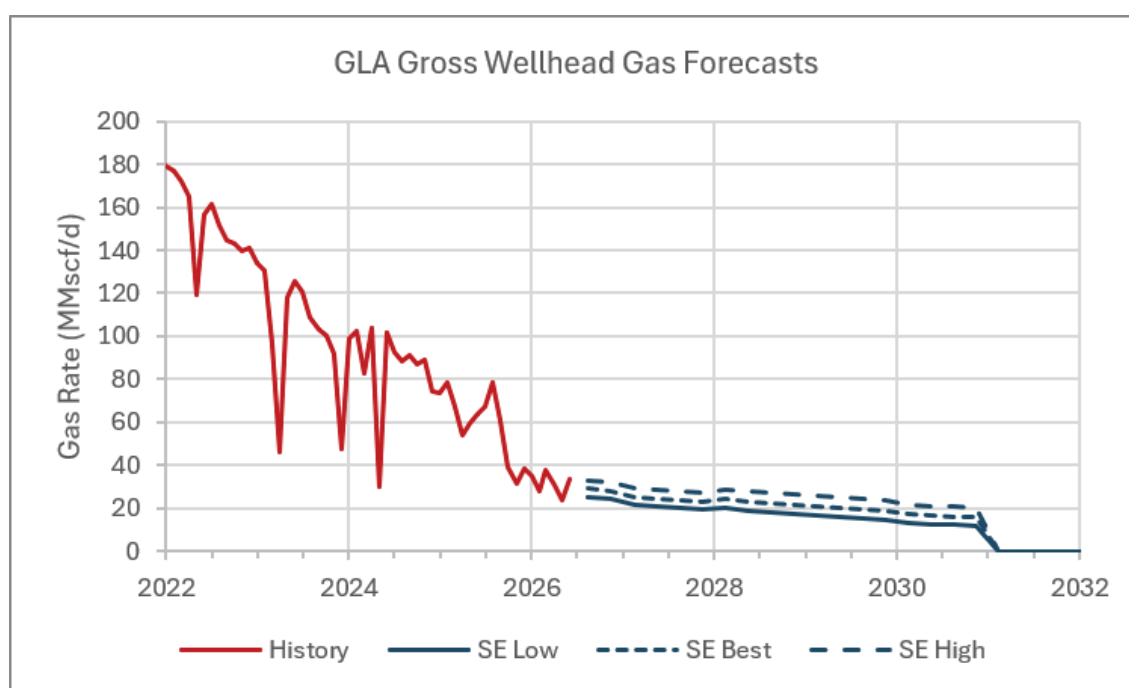


Figure 3.8: GLA gross wellhead gas production forecasts

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).

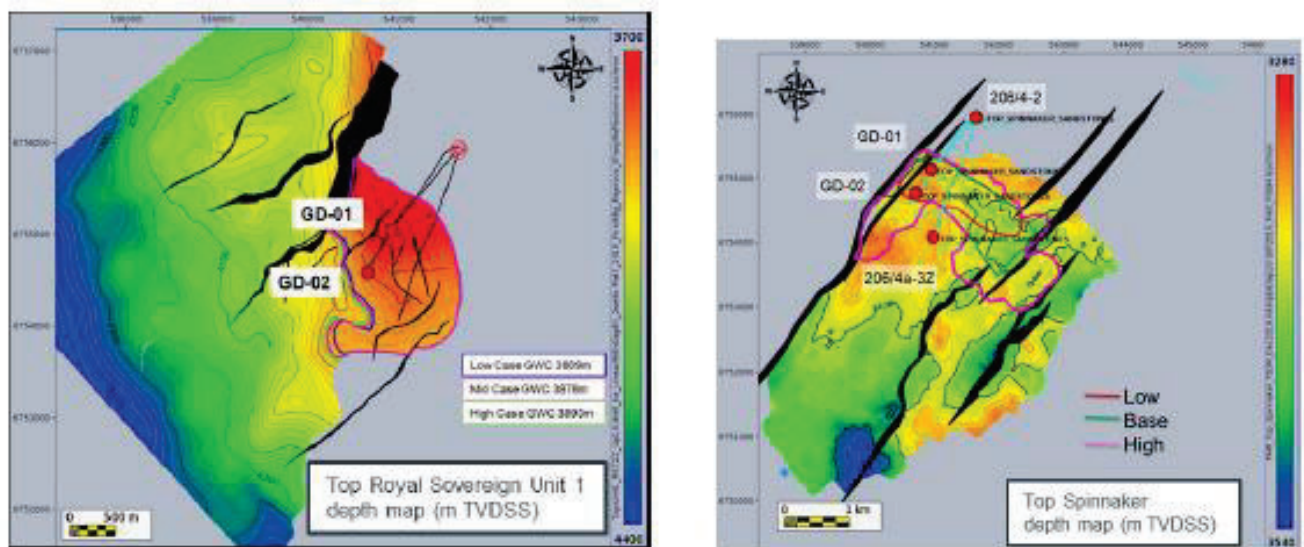


Figure 3.9: ERSS discovery top structure map of primary and secondary targets

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*

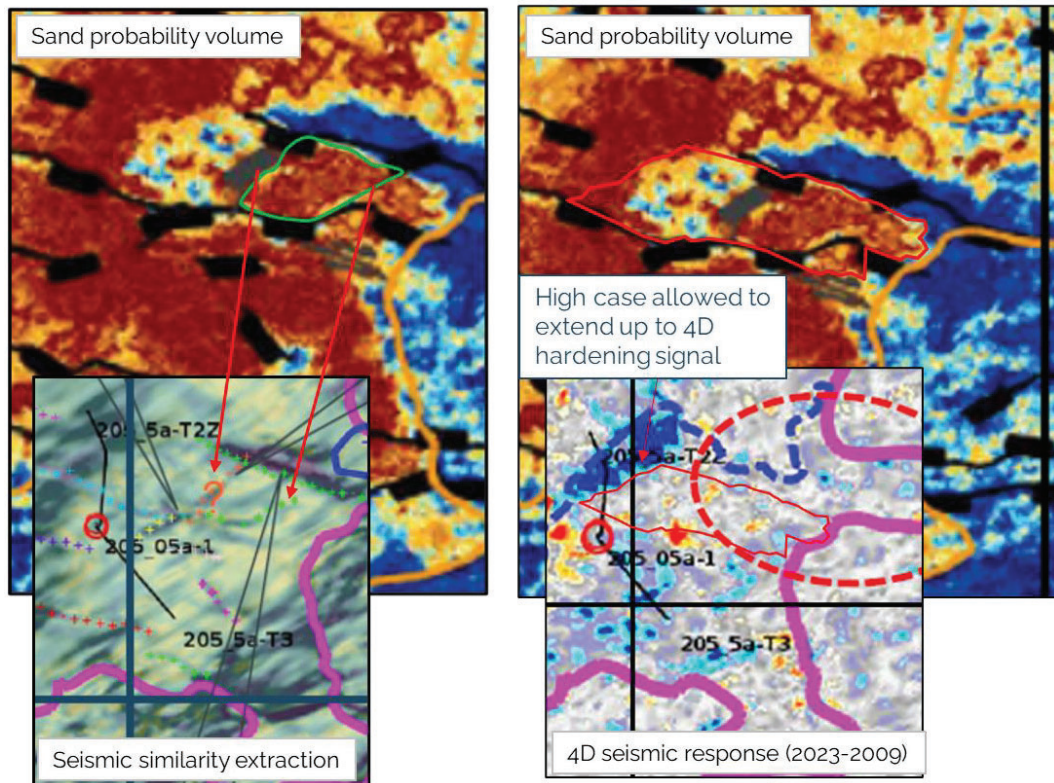


Figure 3.10: Assessed Tormore infill location with Sproule ERCE low and high case areas

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.

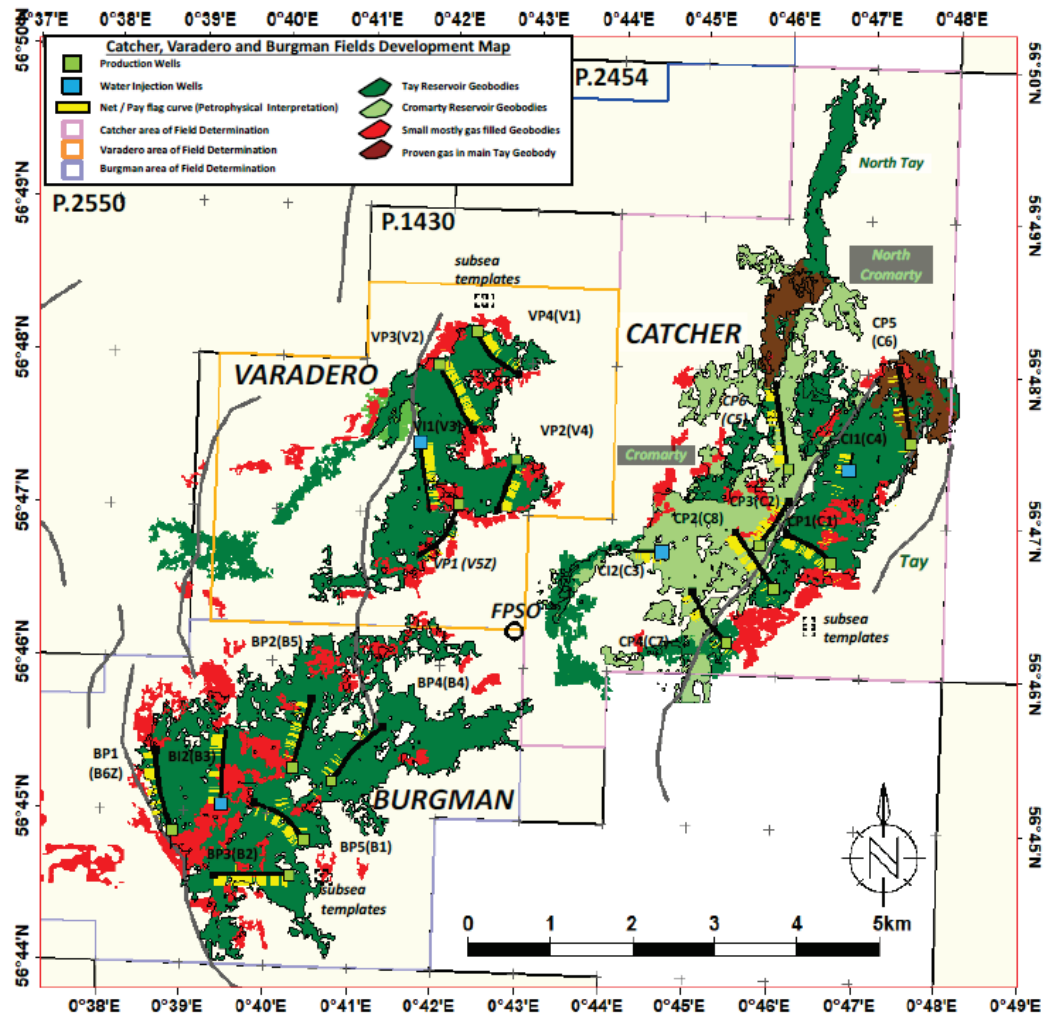


Figure 4.1: Overview of blocks, Catcher Area

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.

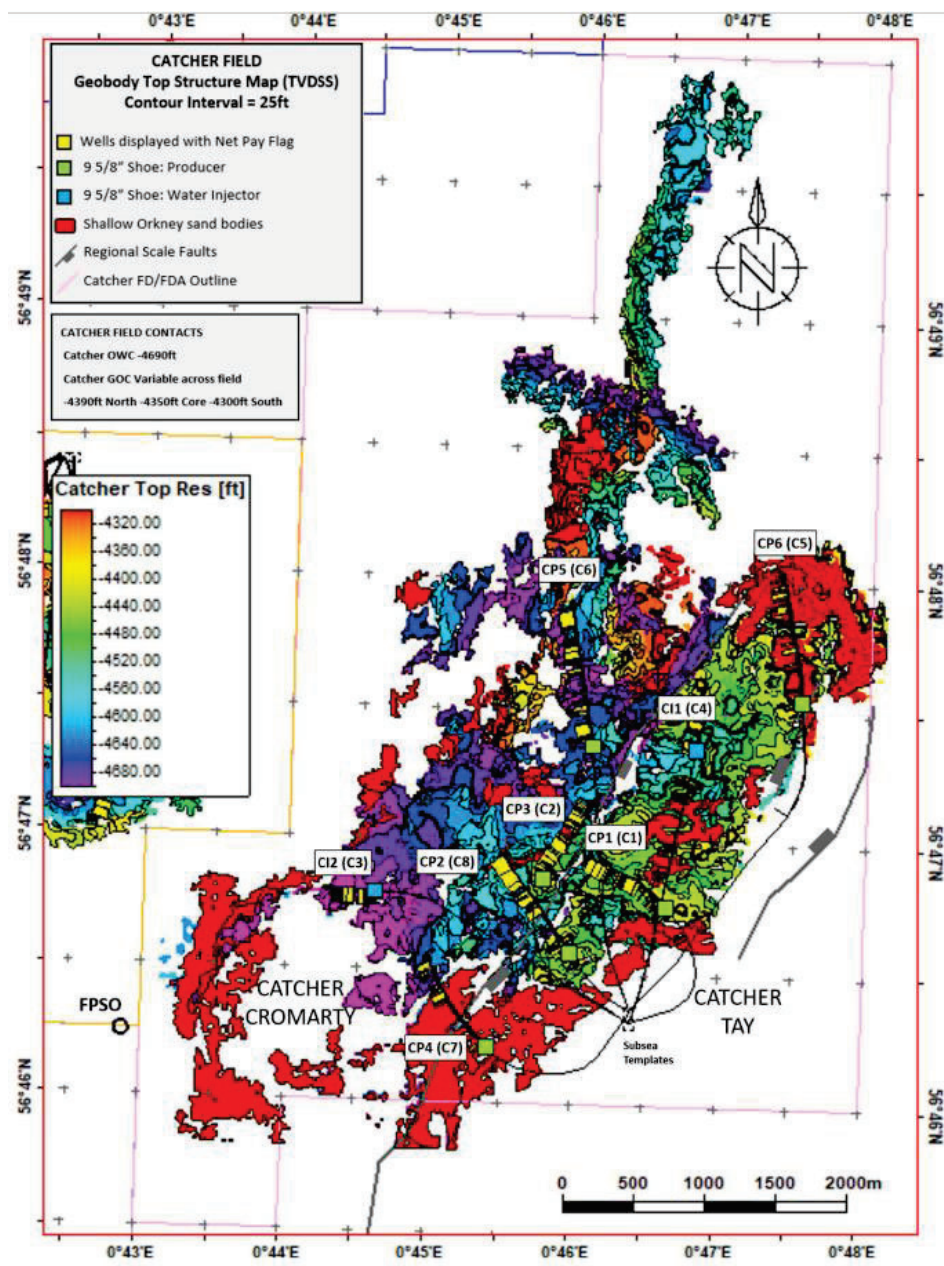


Figure 4.2: Catcher field Top Cromarty and Top Tay depth structure maps

Source: Operator

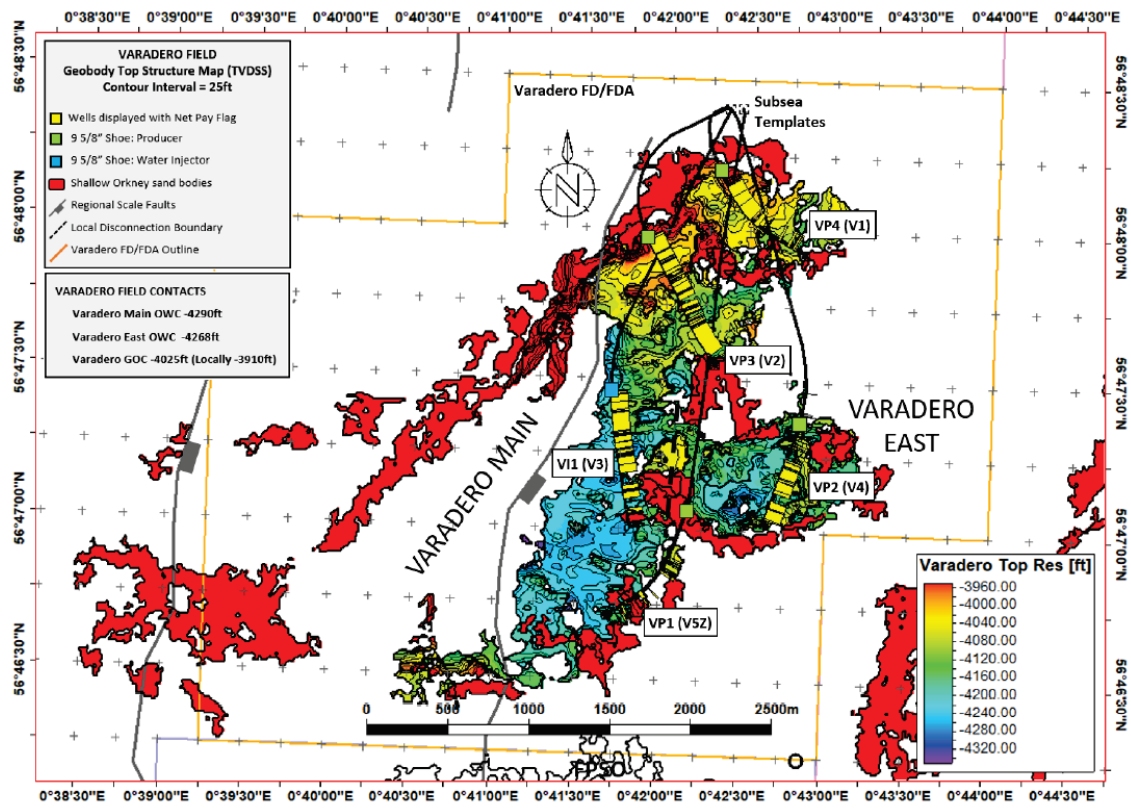


Figure 4.3: Varadero field Top Tay depth structure maps

Source: Operator

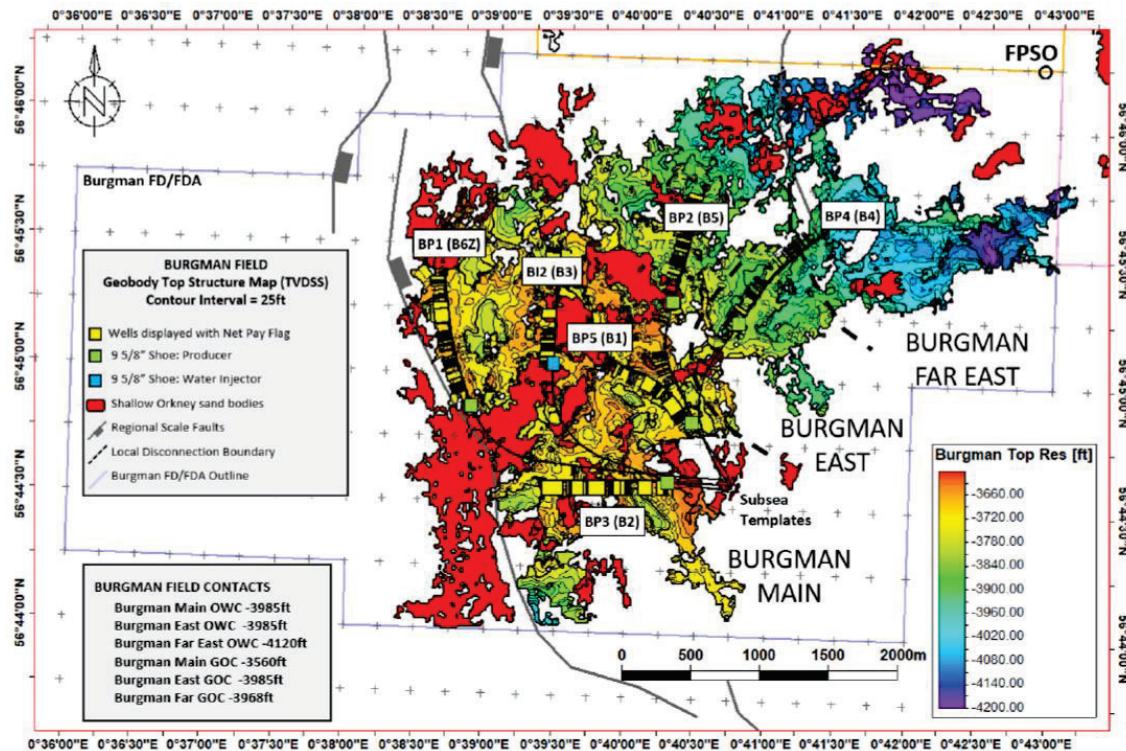


Figure 4.4: Burgman field Top Cromarty depth structure maps

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.

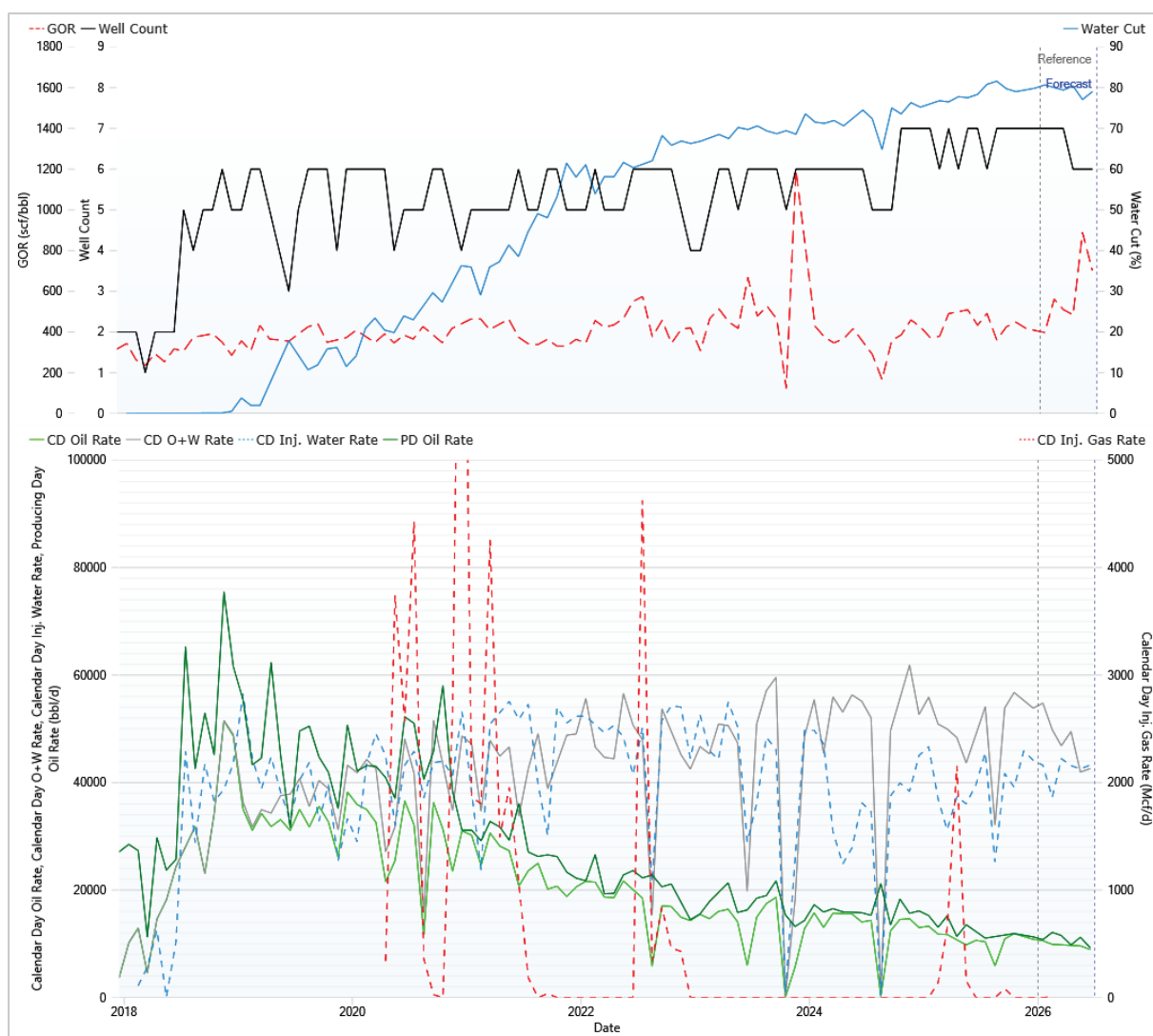


Figure 4.5: Catcher Field production and injection history



Figure 4.6: Varadero Field production and injection history

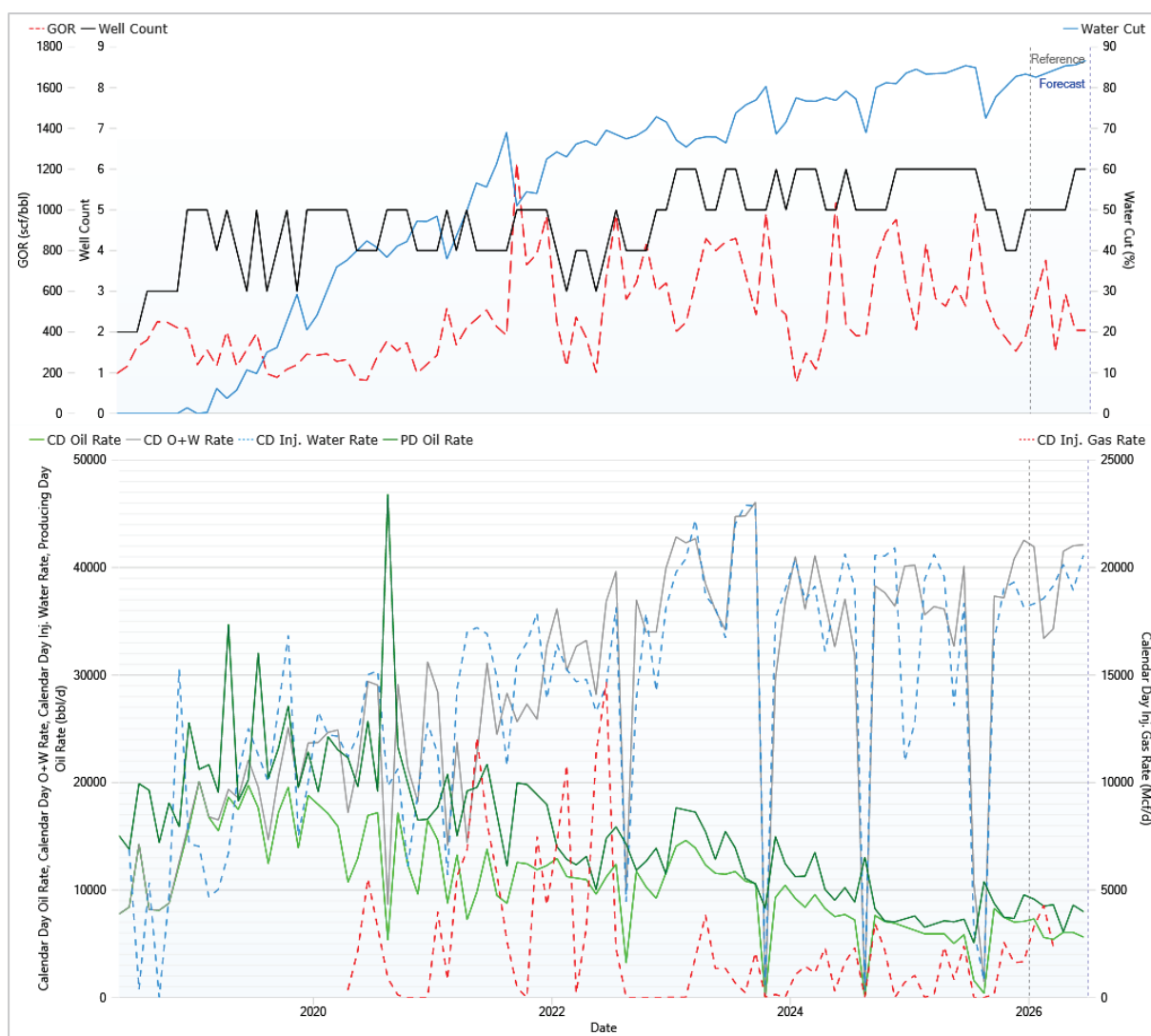


Figure 4.7: Burgman Field production and injection history

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.

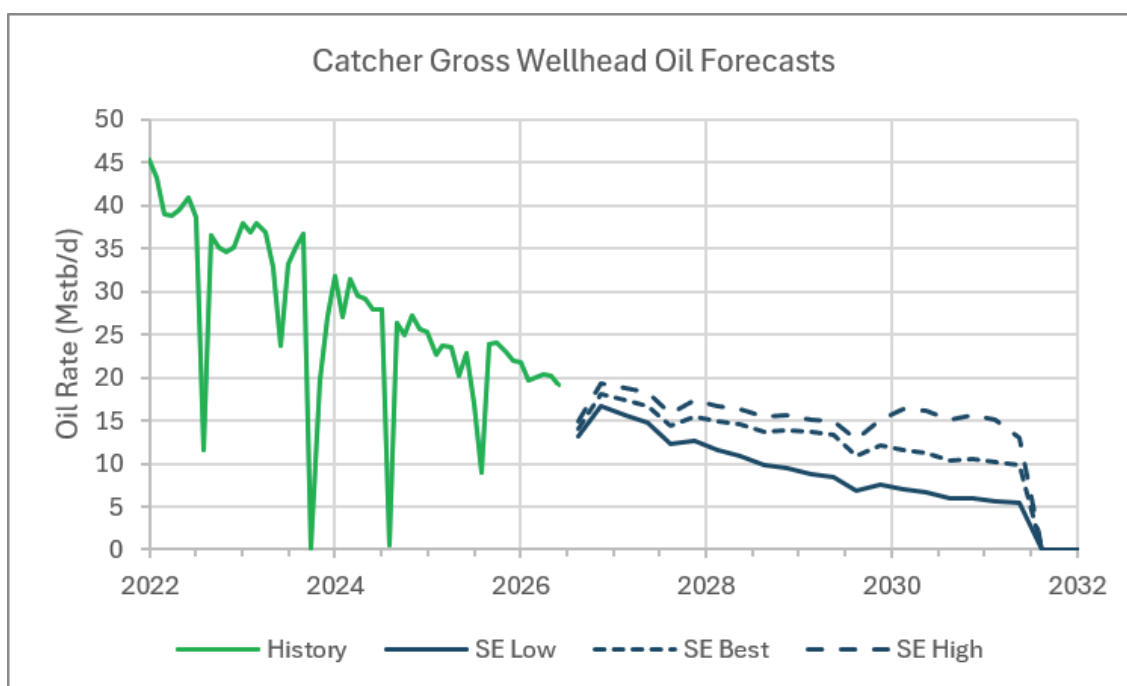


Figure 4.8: Catcher Area gross wellhead oil production forecasts

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.

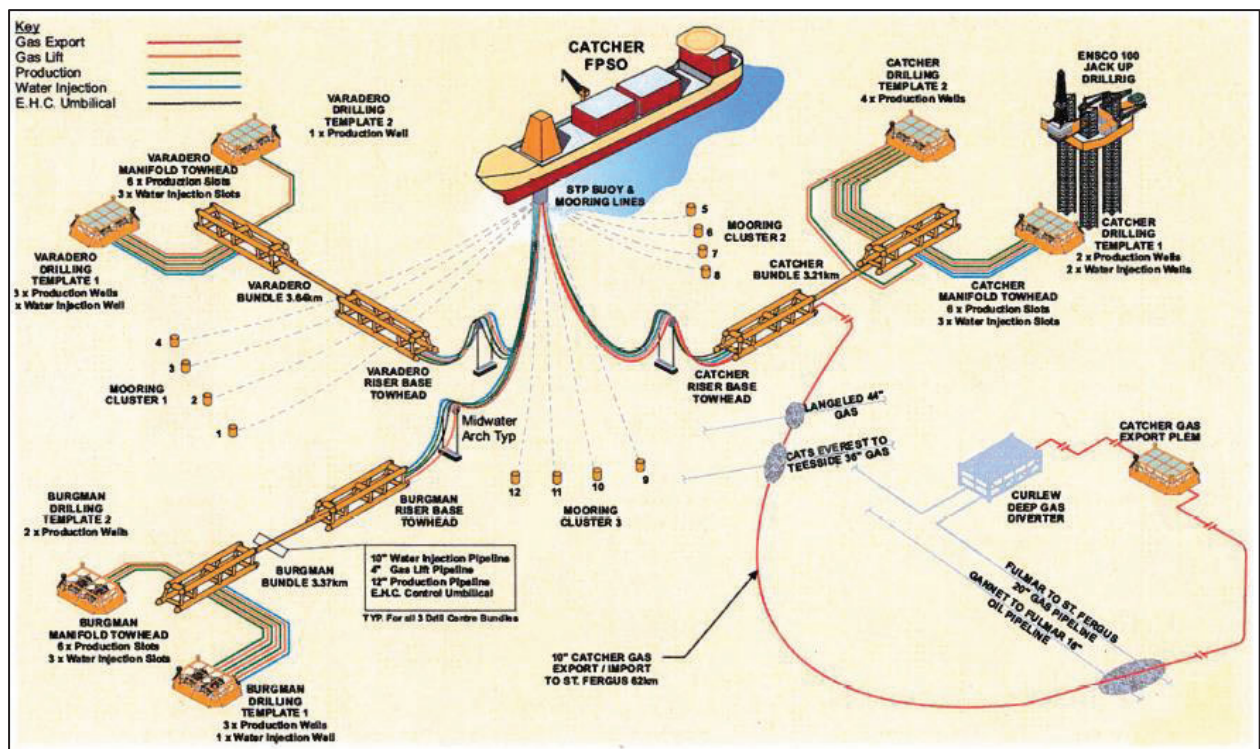


Figure 4.9: Catcher Area development schematic

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.

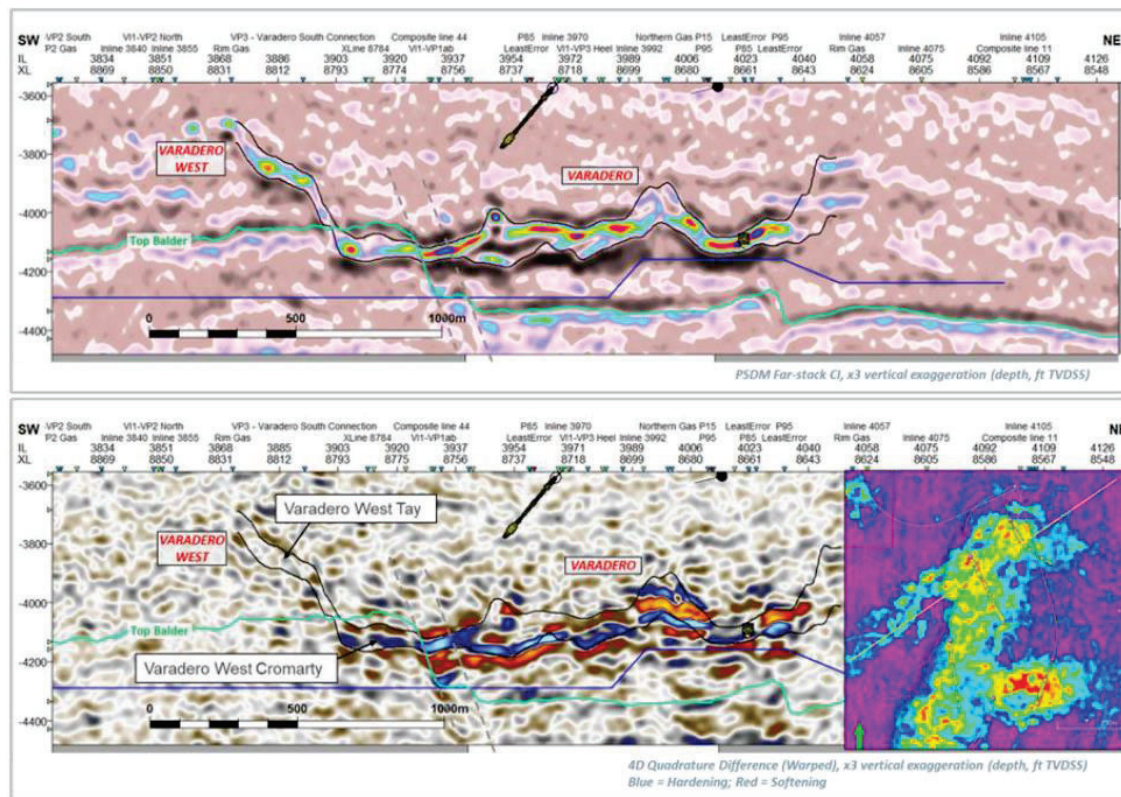


Figure 4.10: NE-SW seismic cross section from Varadero Main to Varadero West

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.

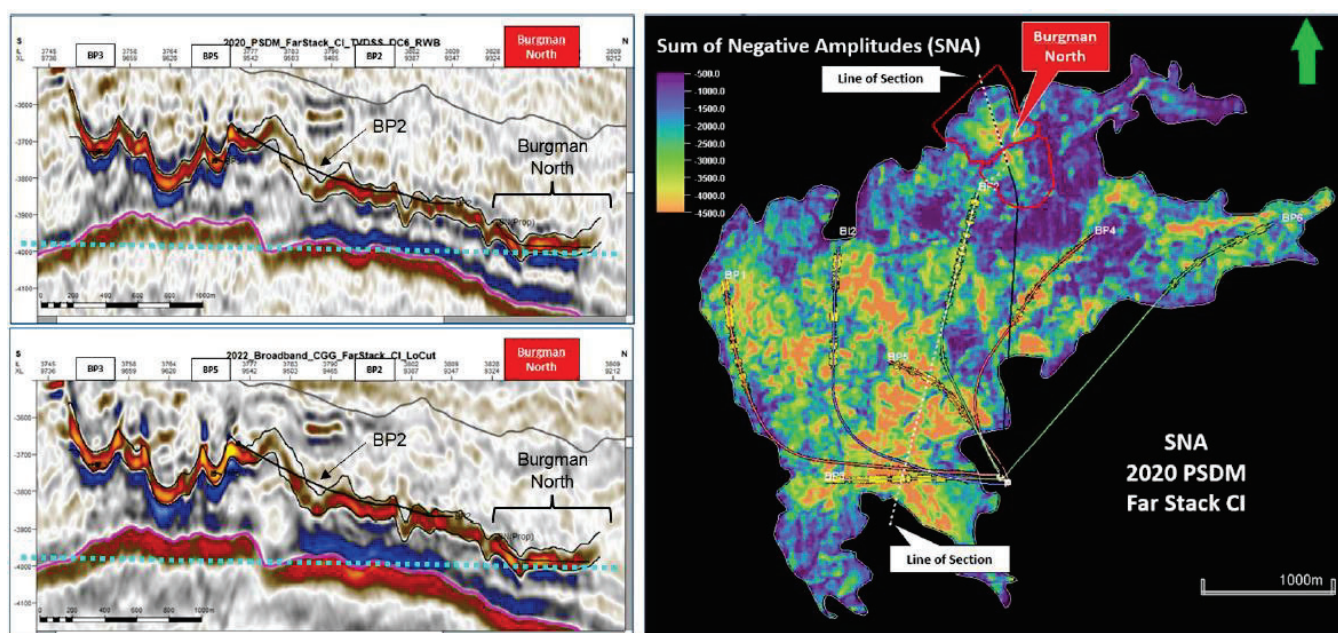


Figure 4.11: N-S seismic cross section through Burgman North (left) and Burgman SNA map (right)

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.

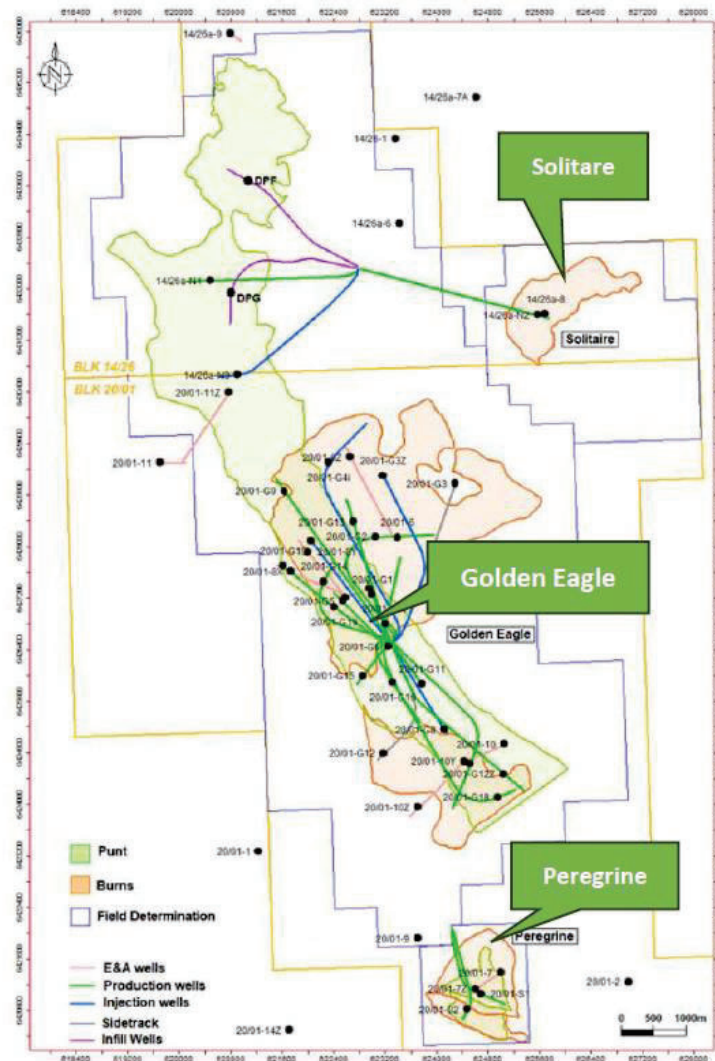


Figure 5.1: Overview of licences, GEAD

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).

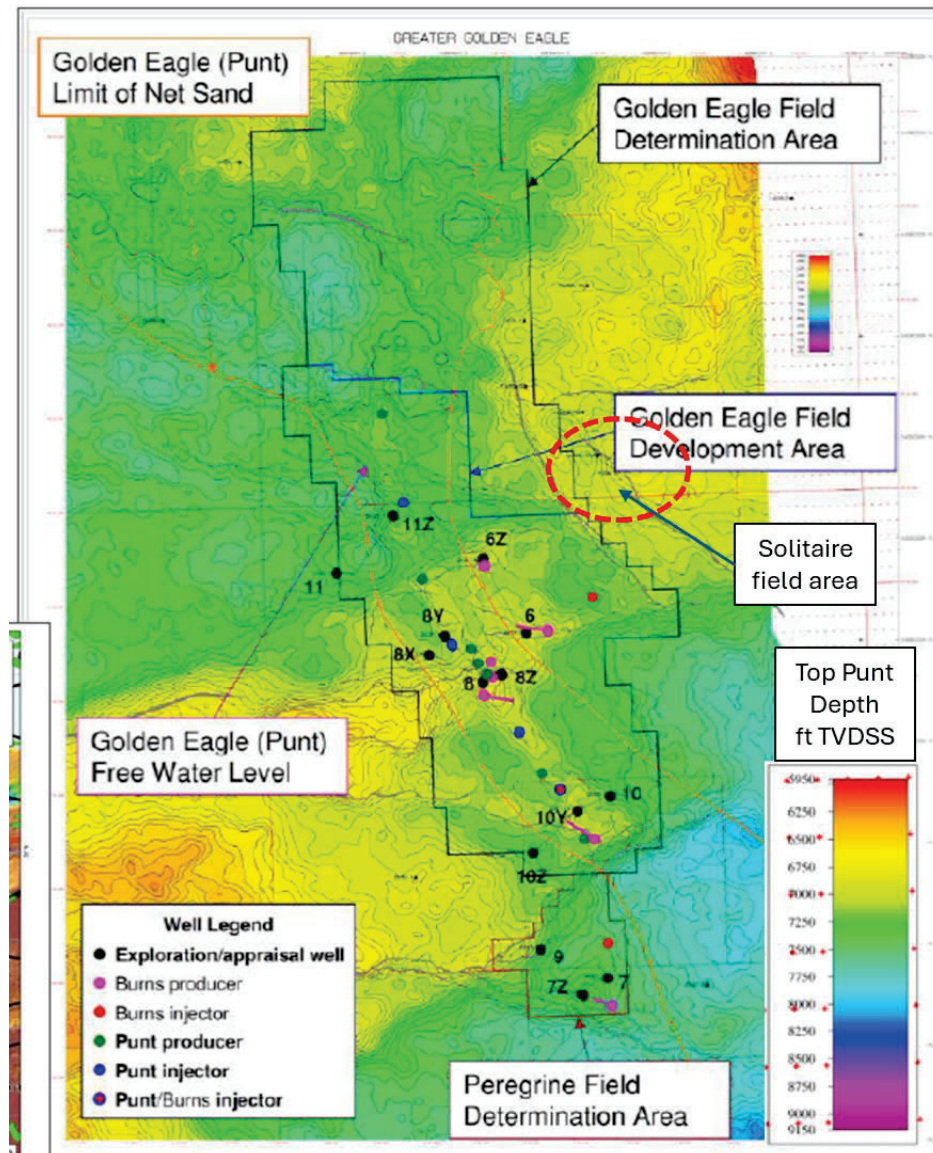


Figure 5.2: GEAD Top Punt depth structure map

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.

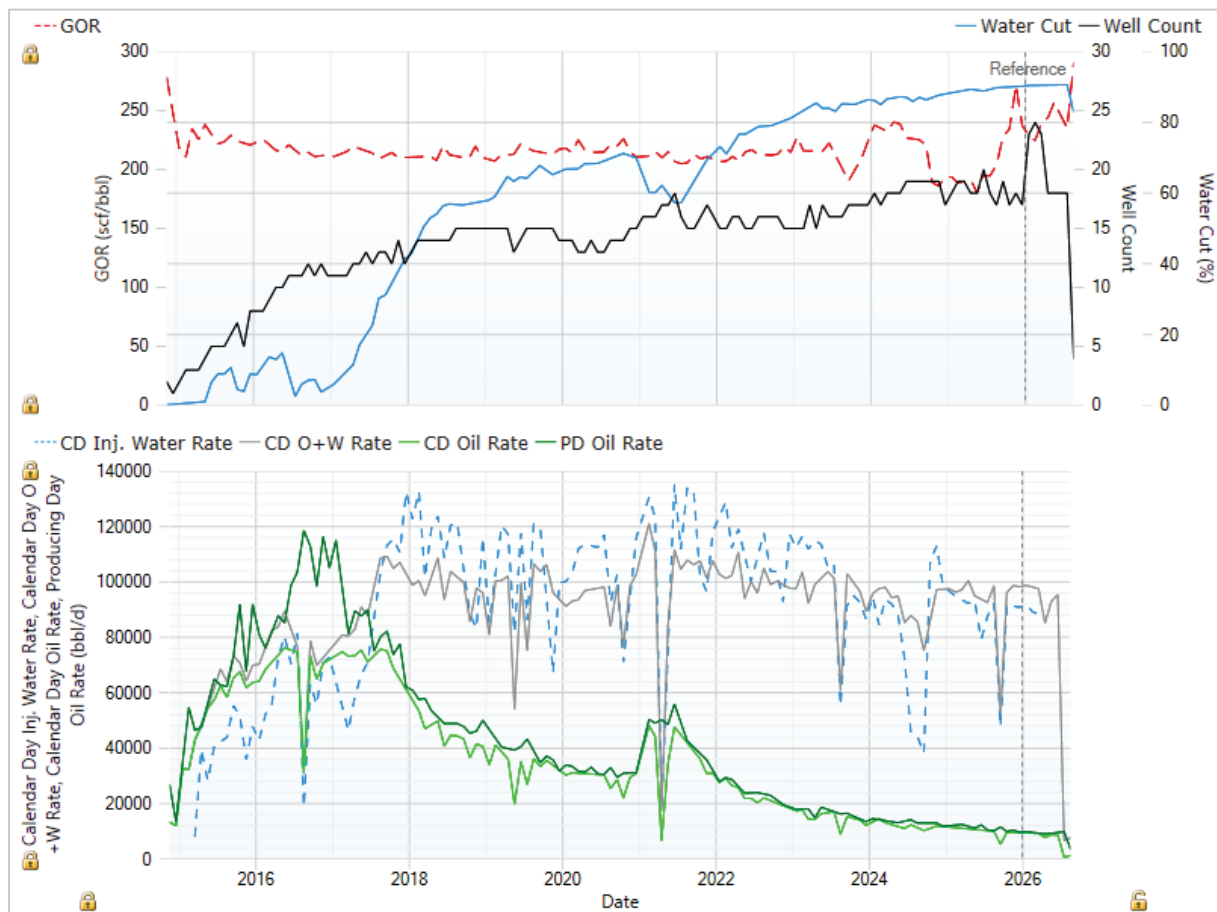


Figure 5.3: GEAD Fields production and injection history

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.

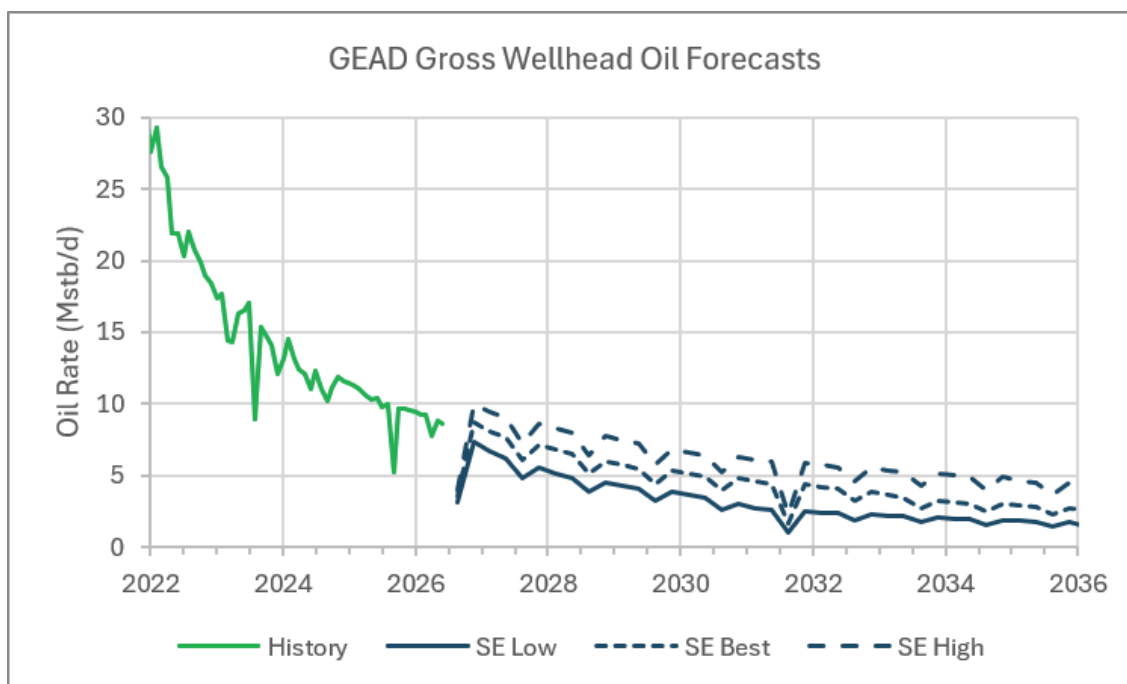


Figure 5.4: GEAD gross wellhead oil production forecasts

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 (Dvpd+Undvpd)	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).

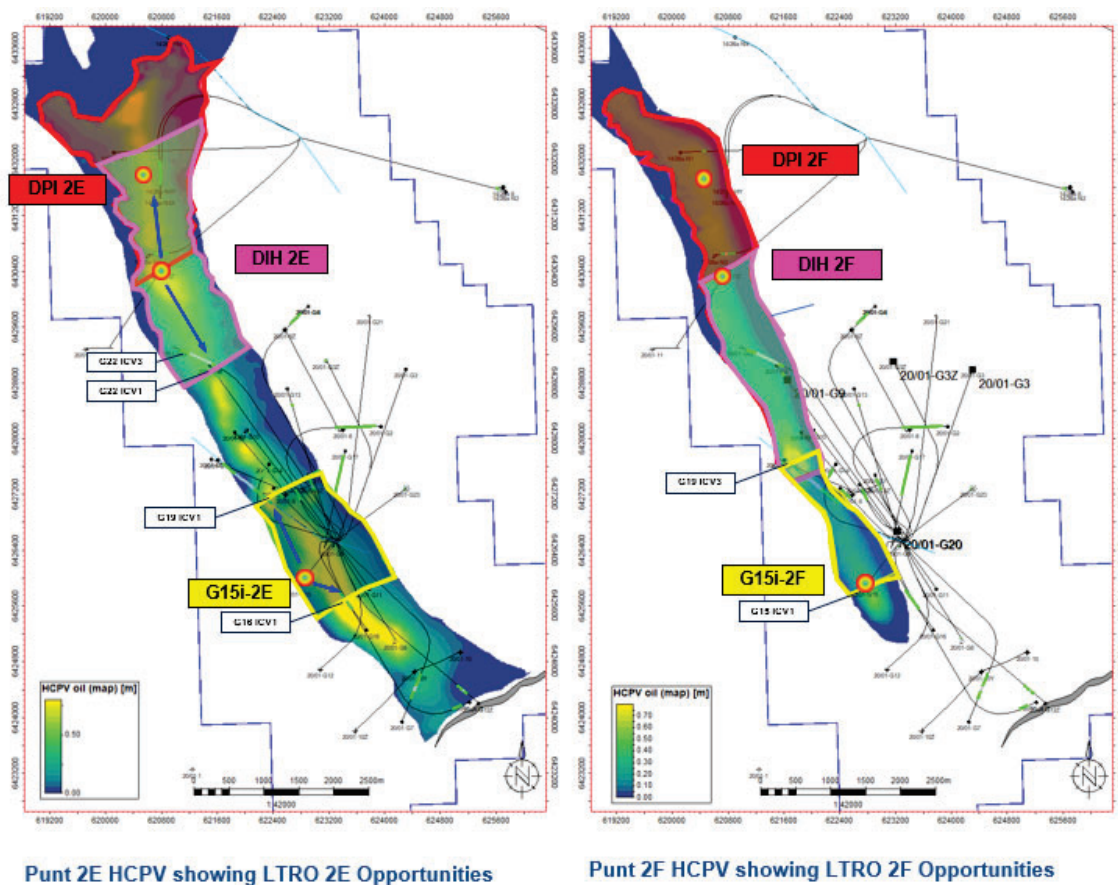


Figure 5.5: Locations of opportunities in Punt 2E and 2F reservoirs

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.

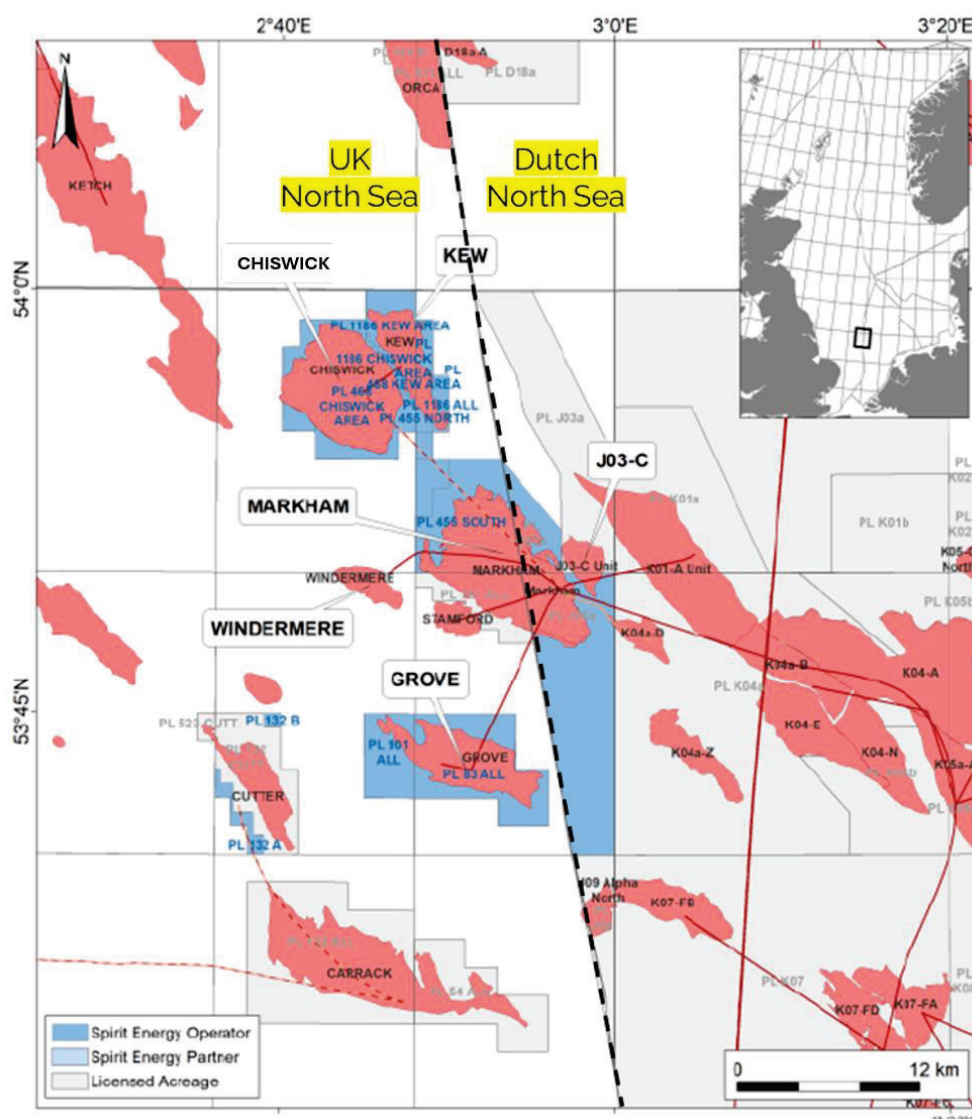


Figure 6.1: Overview of licensed blocks, Greater Markham Area

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.

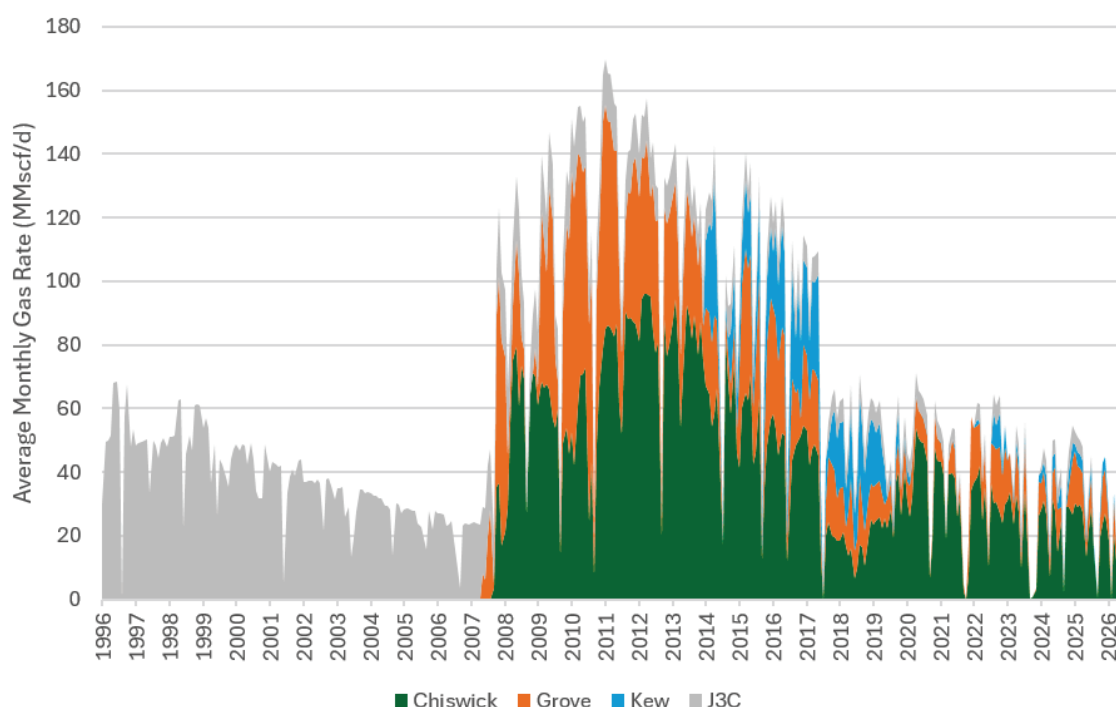


Figure 6.2: GMA gas production history, by field

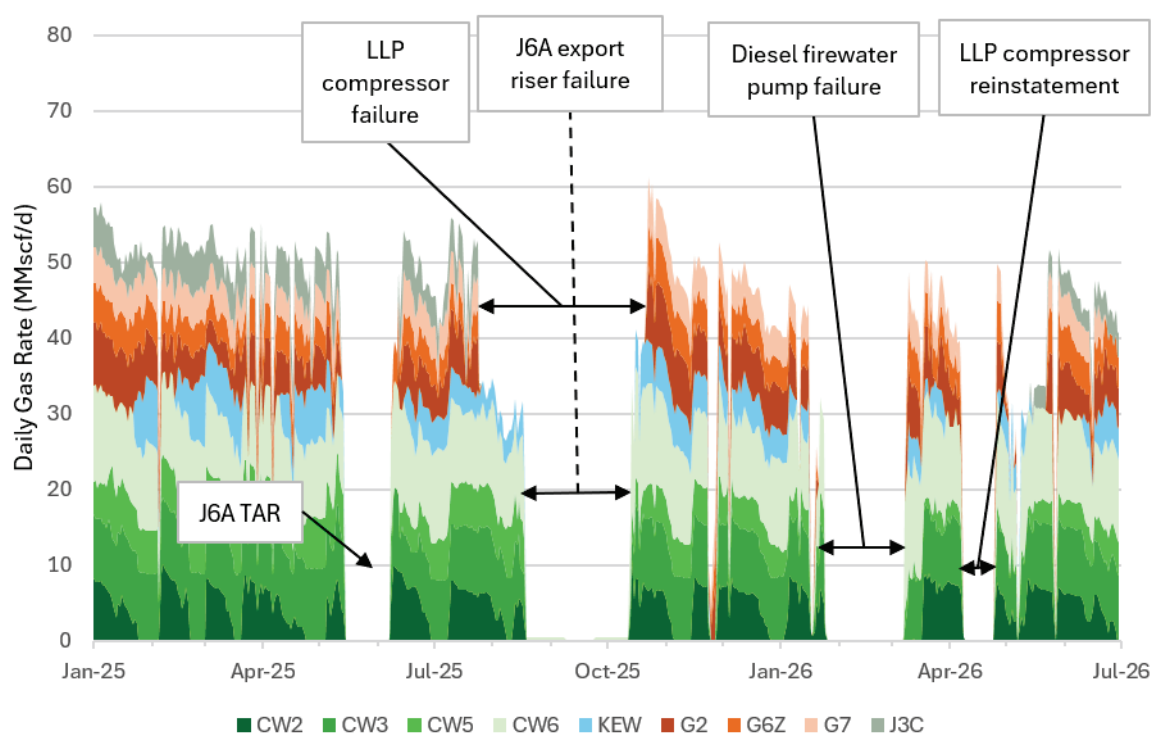


Figure 6.3: GMA daily gas production history, by well (2025 to 30 June 2026)

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.

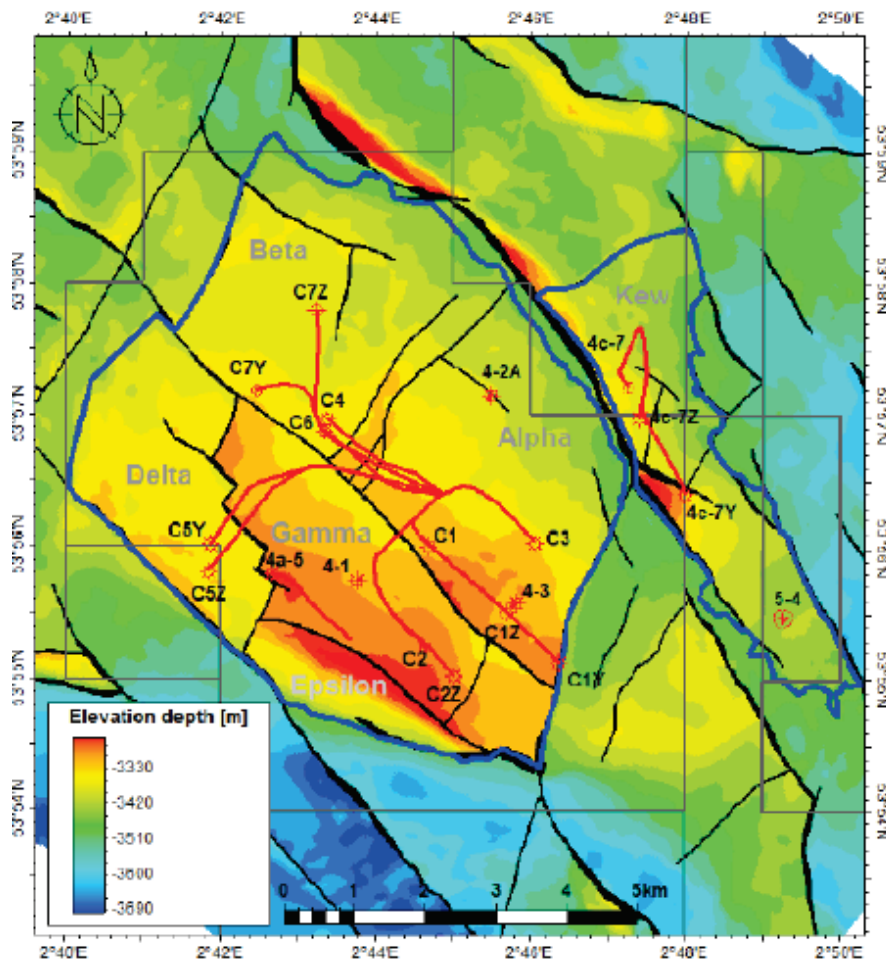


Figure 6.4: Chiswick field top structure map

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).

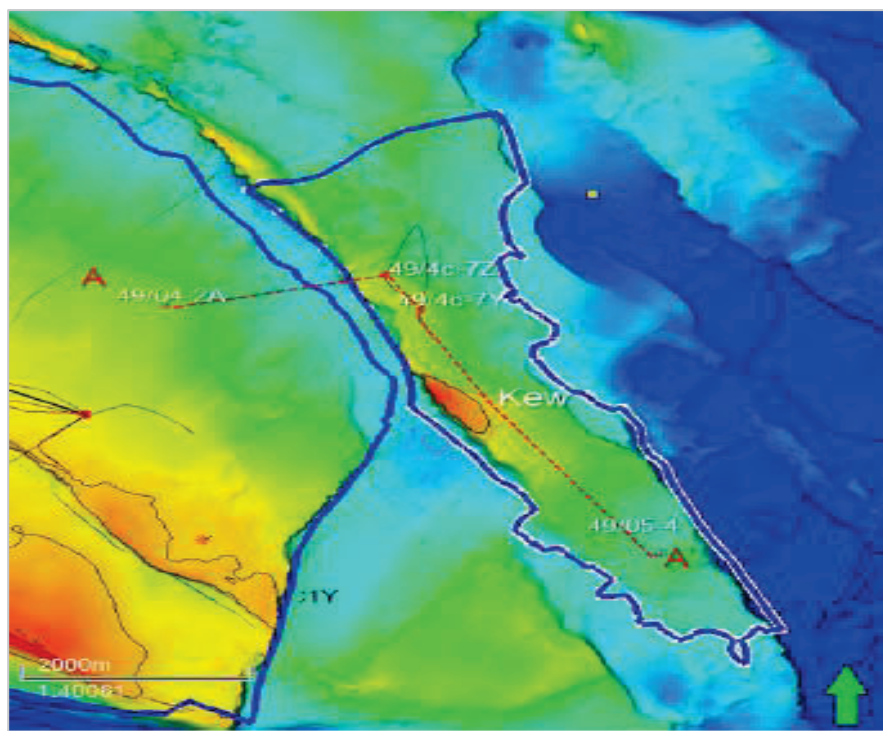


Figure 6.5: Kew field top structure map

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.

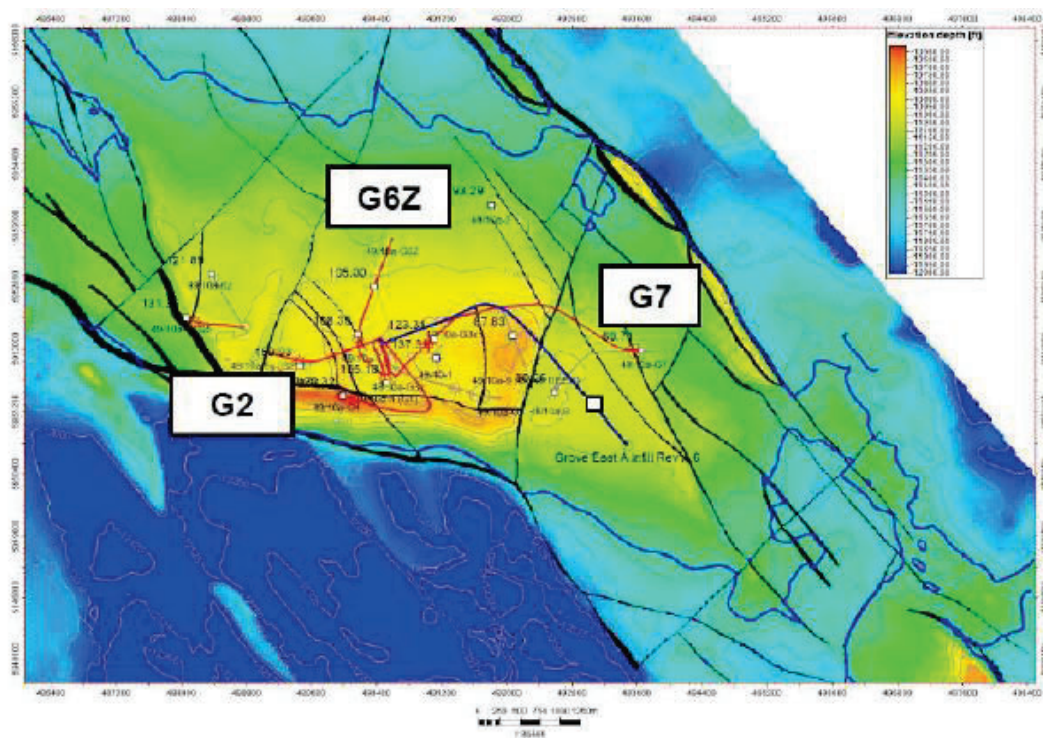


Figure 6.6: Grove field top structure map

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.

A total of seven wells have been drilled, including exploration and appraisal wells, in the different fault blocks. In June 2026, three wells were online and produced an average of 12 MMscf/d of gas, with 107 bbl/d of condensate; cumulative production, as at 30 June 2026, was 154 Bscf of gas and 1.5 MMstb of condensate.

J3C Field

The J3C Field was discovered in 1995 by Well J6-A5, which encountered gas-bearing Lower Slochteren reservoir. In this area of the North Sea, the prolific Leman Sandstone reservoir thins out towards the centre of the Silver Pit Basin. Similar to the Markham Field, the J3C Field lies within outliers of good quality Leman Sandstone. The majority of net reservoir lies in the lower three zones, dominated by high-quality aeolian sandstones.

The field was developed by recompleting the discovery well, Well J6-A5. The well was shut-in from late August 2025 to end of April 2026 due to the LLP failure on the K6A platform. In June 2026, the well produced an average of 3 MMscf/d of gas, with 13 bbl/d of condensate; cumulative production, as at 30 June 2026, was 211 Bscf of gas and 0.9 MMstb of condensate.

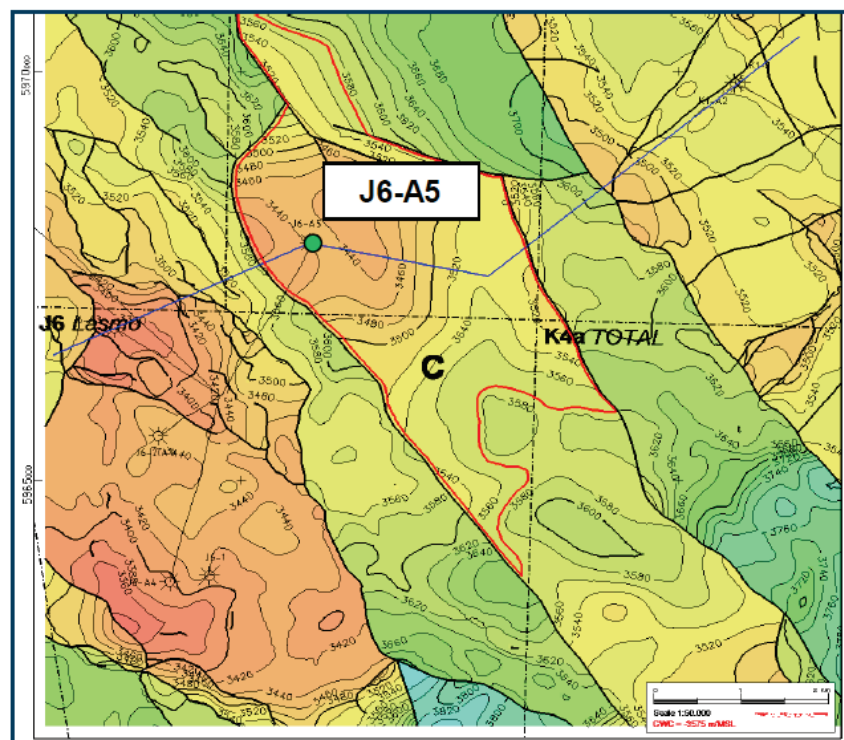


Figure 6.7: J3-C Field top structure map

Source: Operator

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.

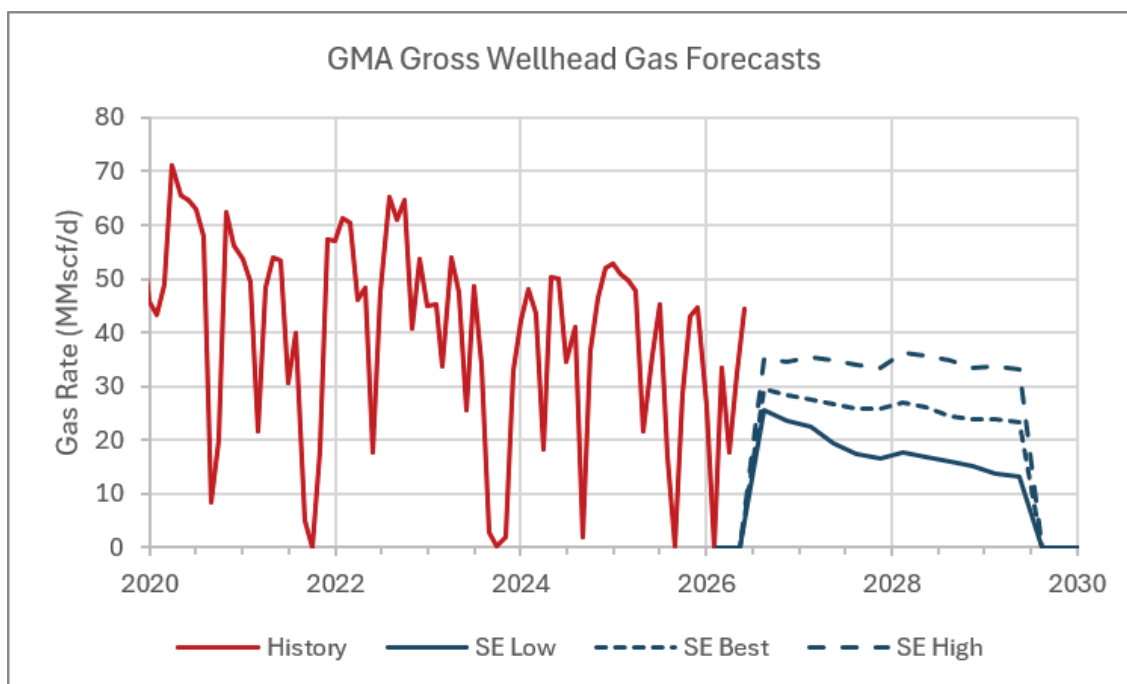


Figure 6.8: GMA gross wellhead gas production forecasts

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 (Dvpd+Undvpd)	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 (Dvpd+Undvpd)	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 (Dvpd+Undvpd)	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 (Dvpd+Undvpd)	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.

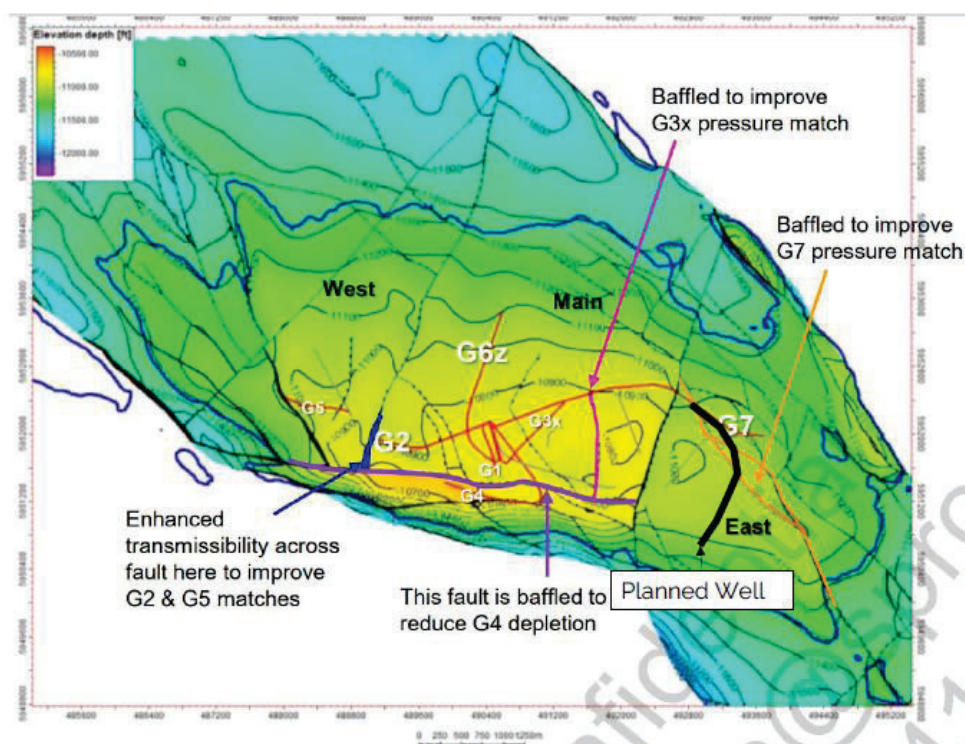


Figure 6.9: Grove East Area and planned well location

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.

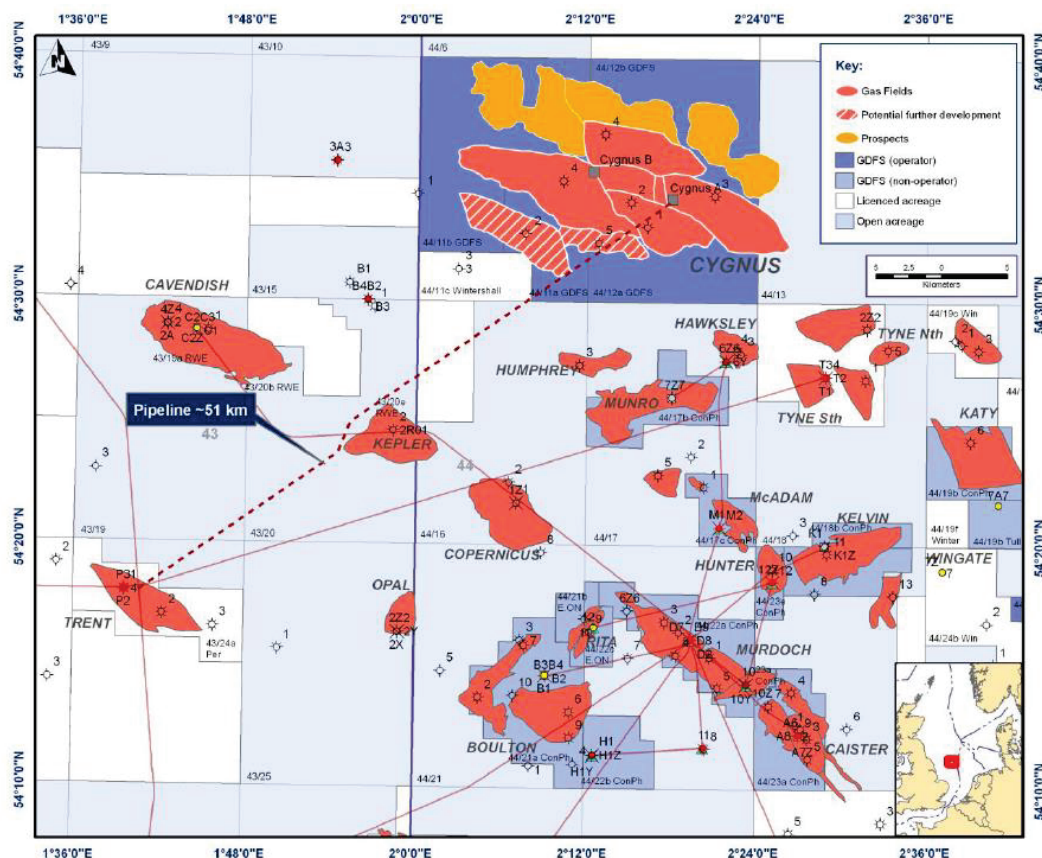


Figure 7.1: Cygnus Field location map

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.

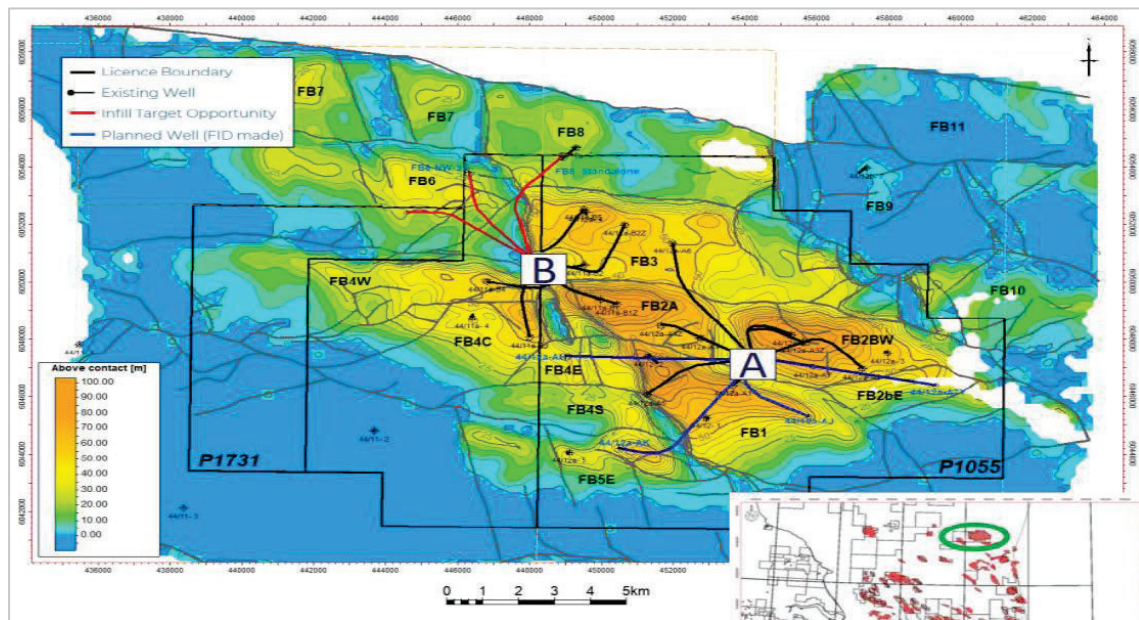


Figure 7.2: Cygnus top Leman depth structure map

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.

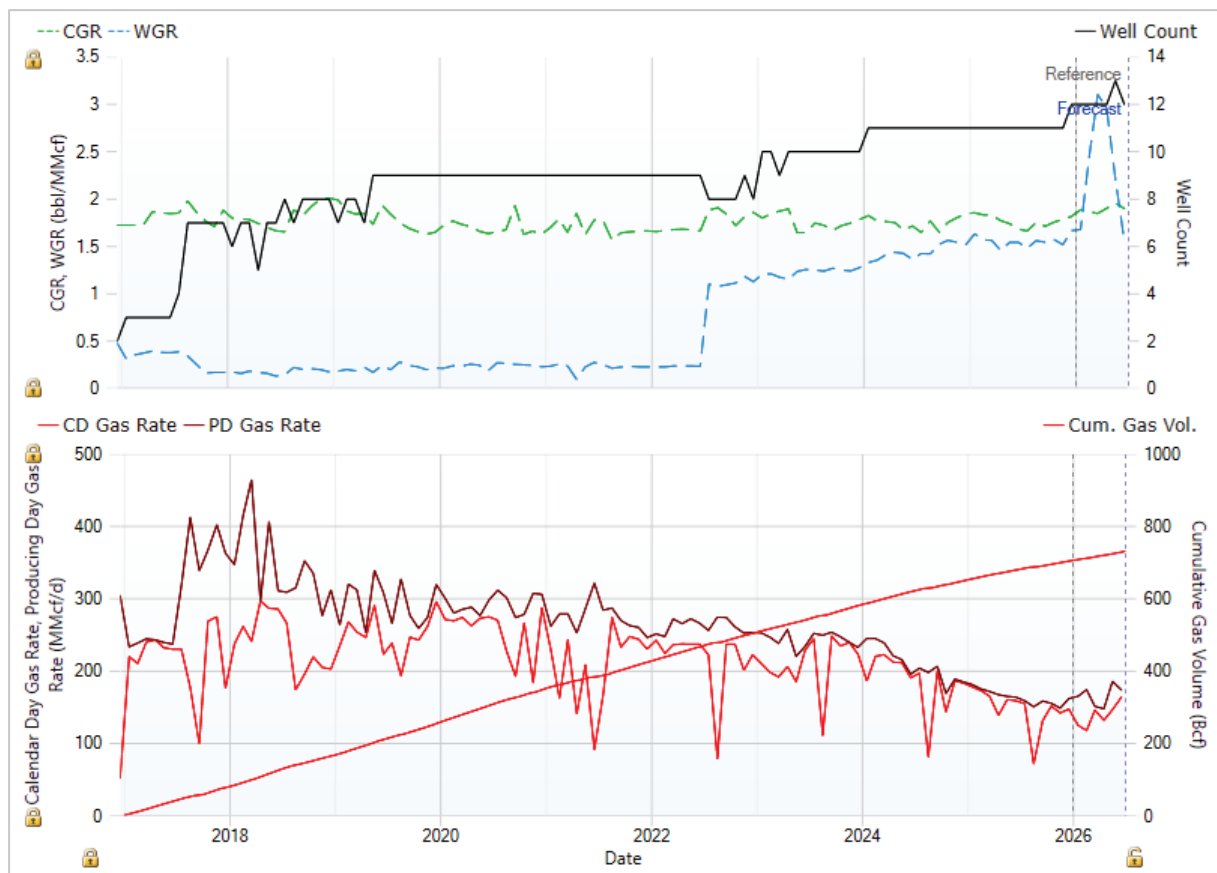


Figure 7.3: Cygnus Field production history

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.

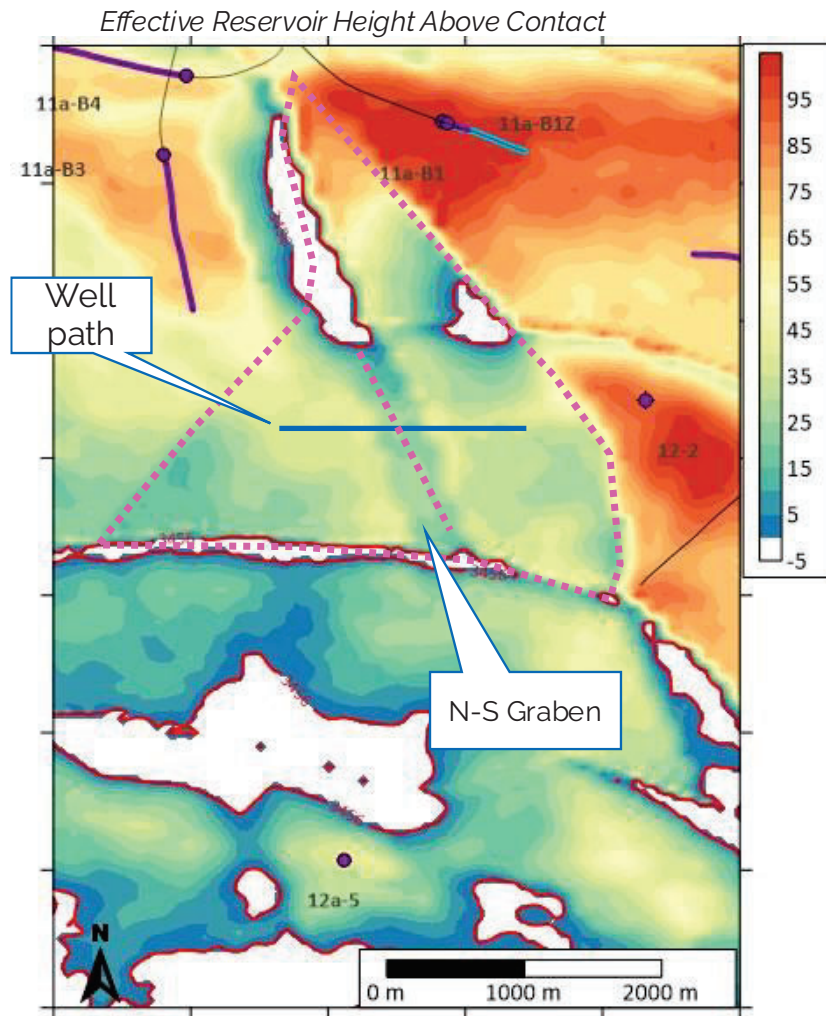


Figure 7.4: Approximate location of infill Well FB4 (14th Well)

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.

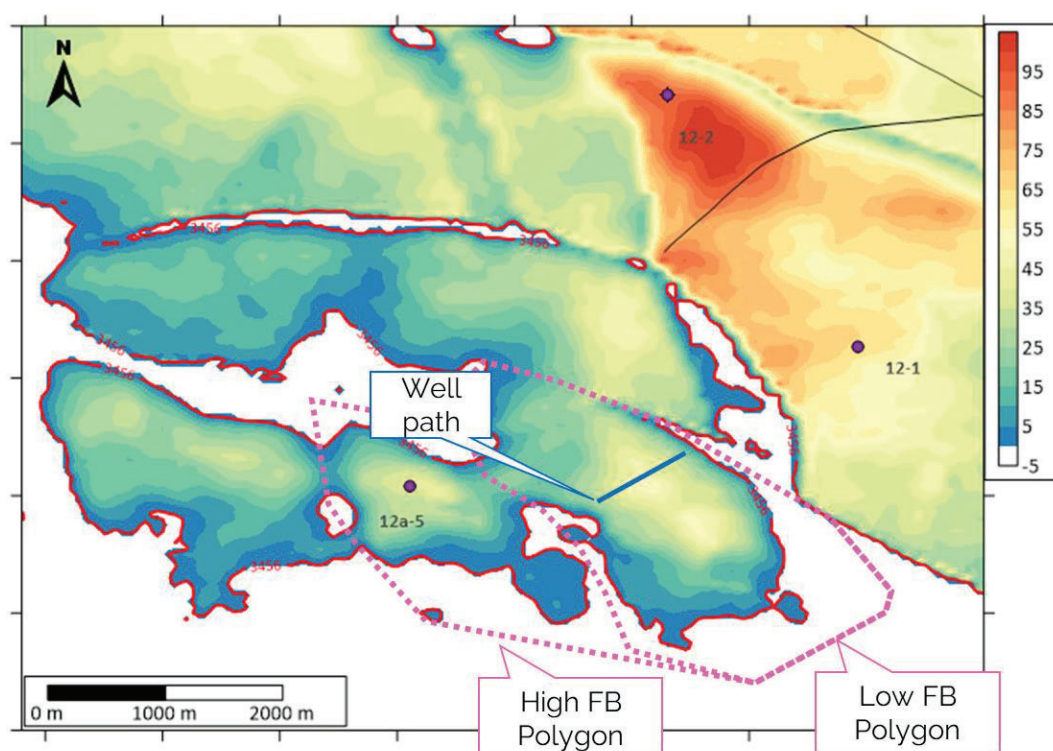


Figure 7.5: Approximate location of infill Well FB5 (15th Well)

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.

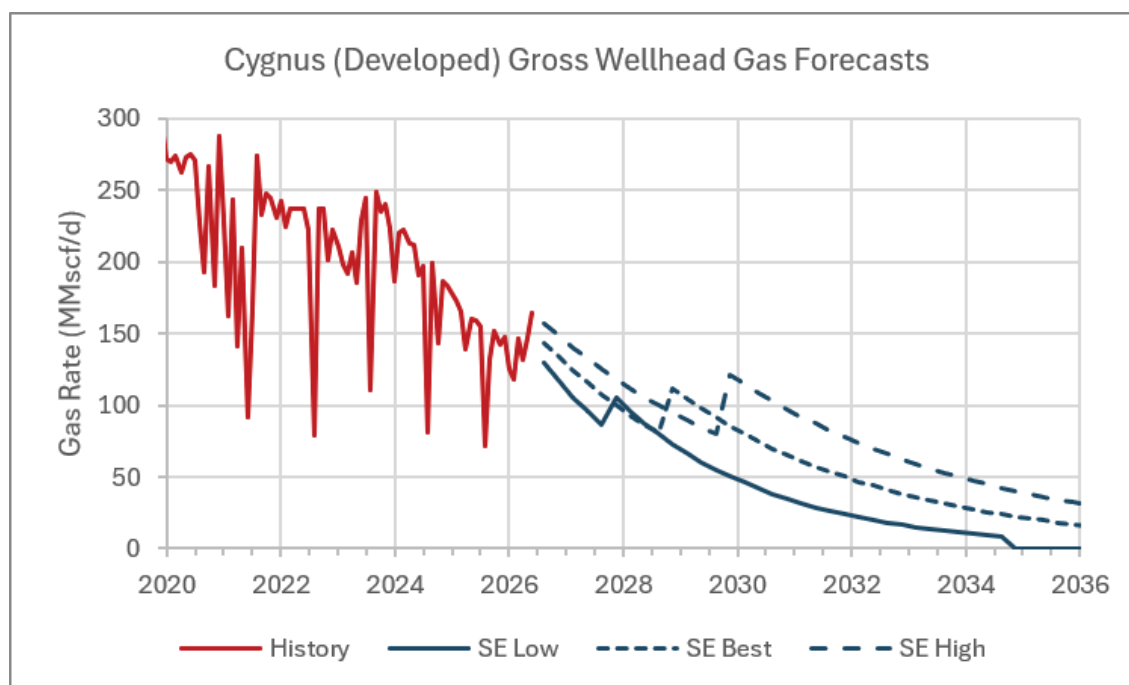


Figure 7.6: Cygnus developed gross wellhead gas production forecasts

SE = Sproule ERCE

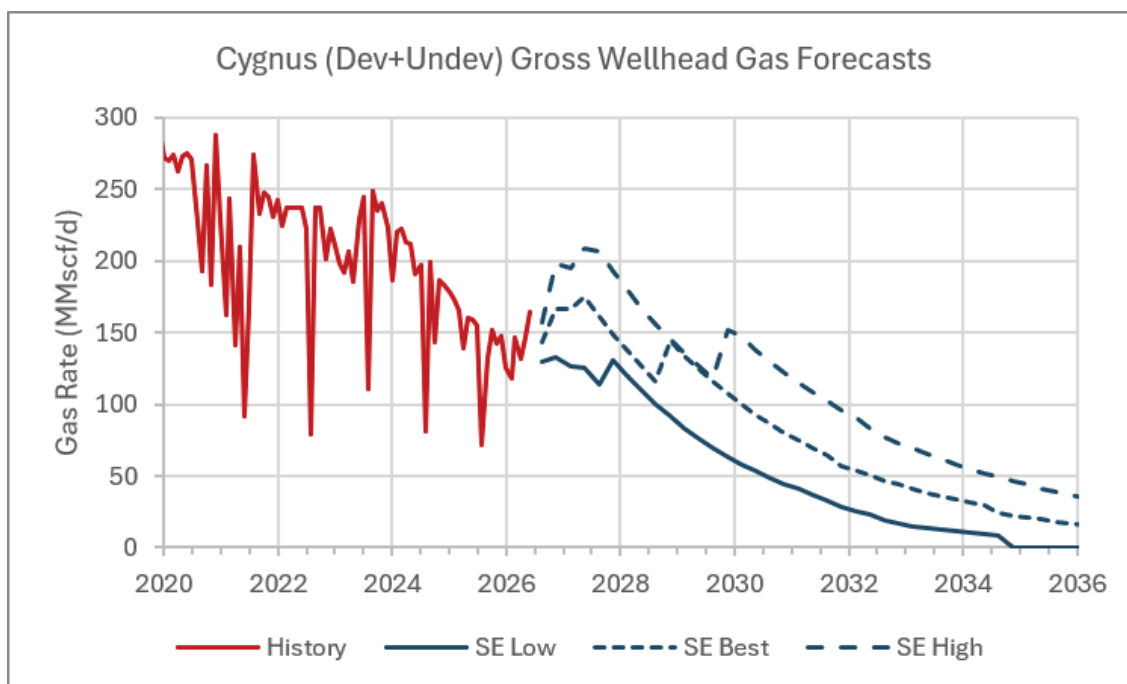


Figure 7.7: Cygnus developed plus undeveloped gross wellhead gas production forecasts

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.

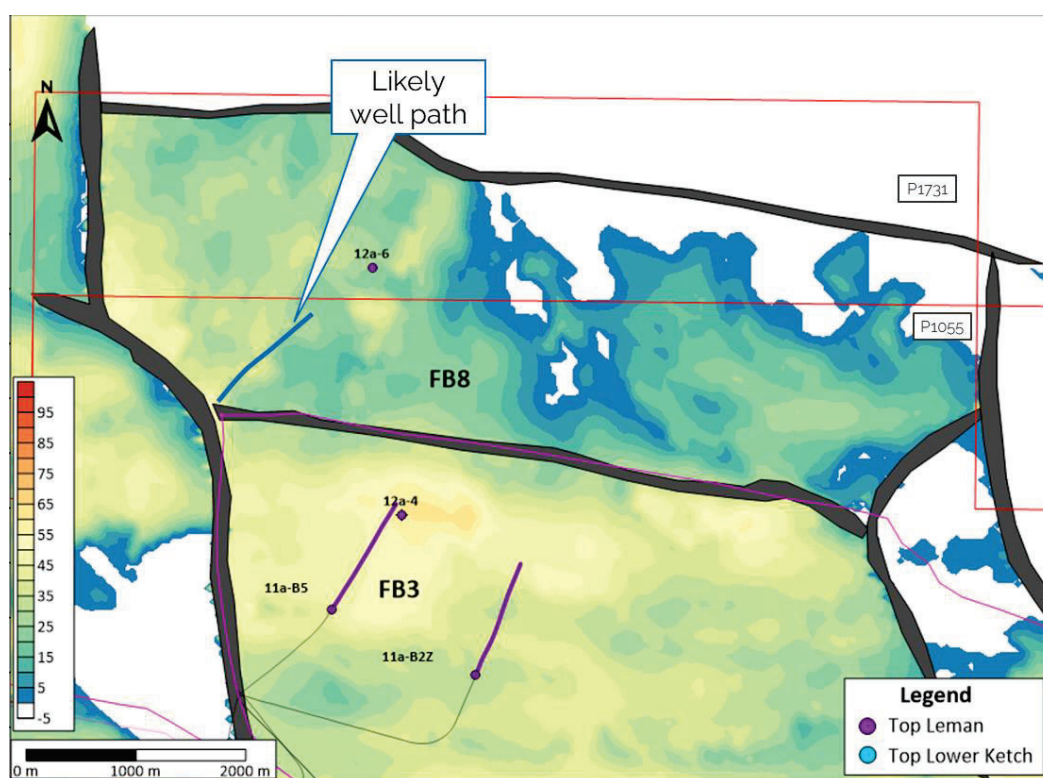


Figure 7.8: Approximate location of infill Well FB8 (16th Well)

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.

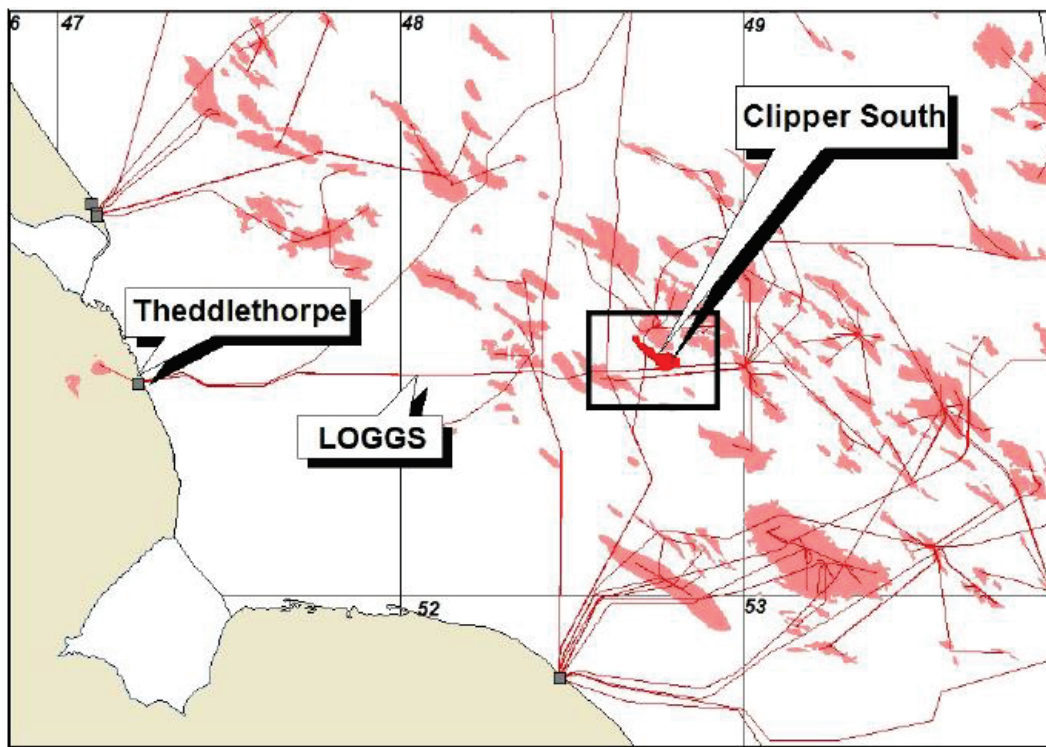


Figure 8.1: Location map of Clipper South gas Field

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).

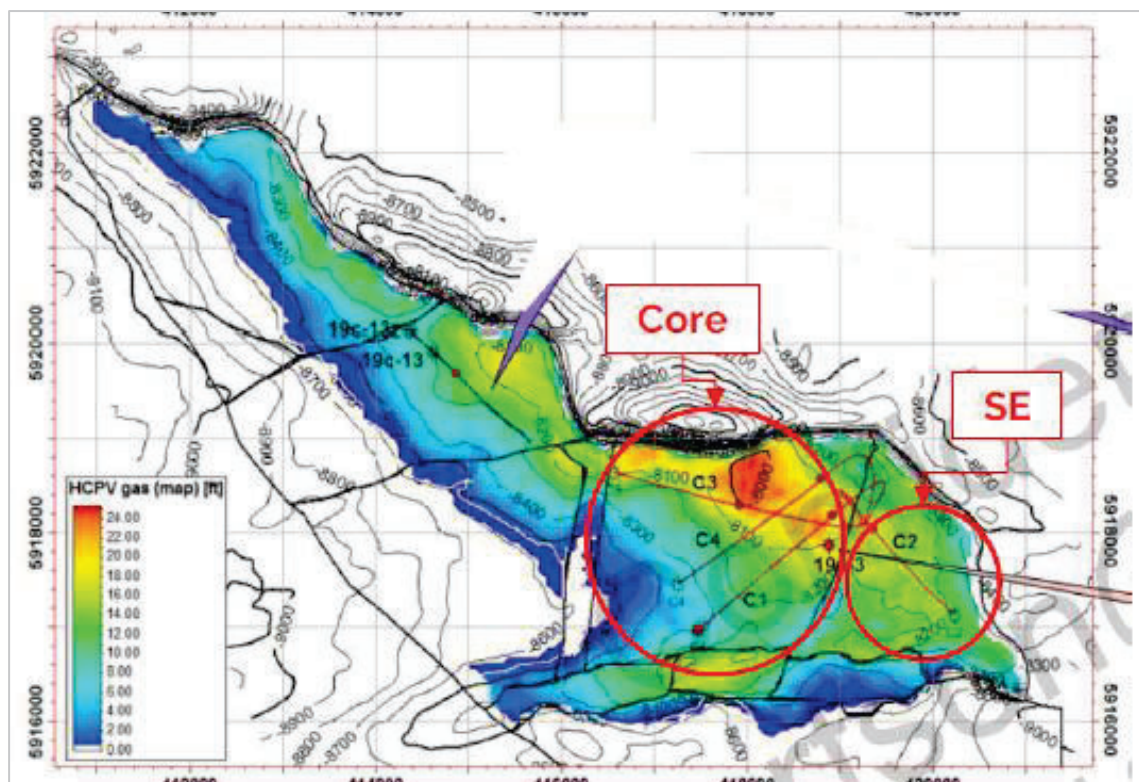


Figure 8.2: Clipper South top structure map

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.

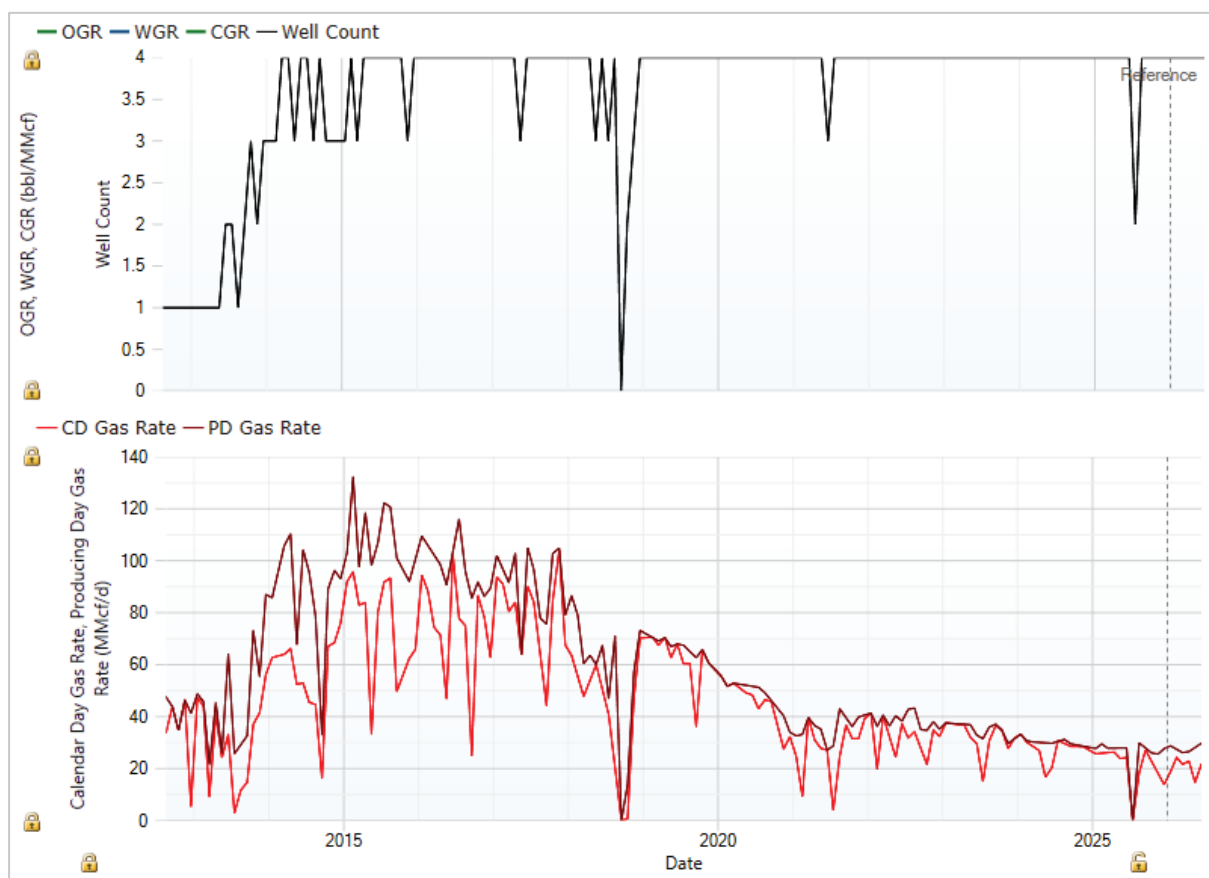


Figure 8.3: Clipper South field production history

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.

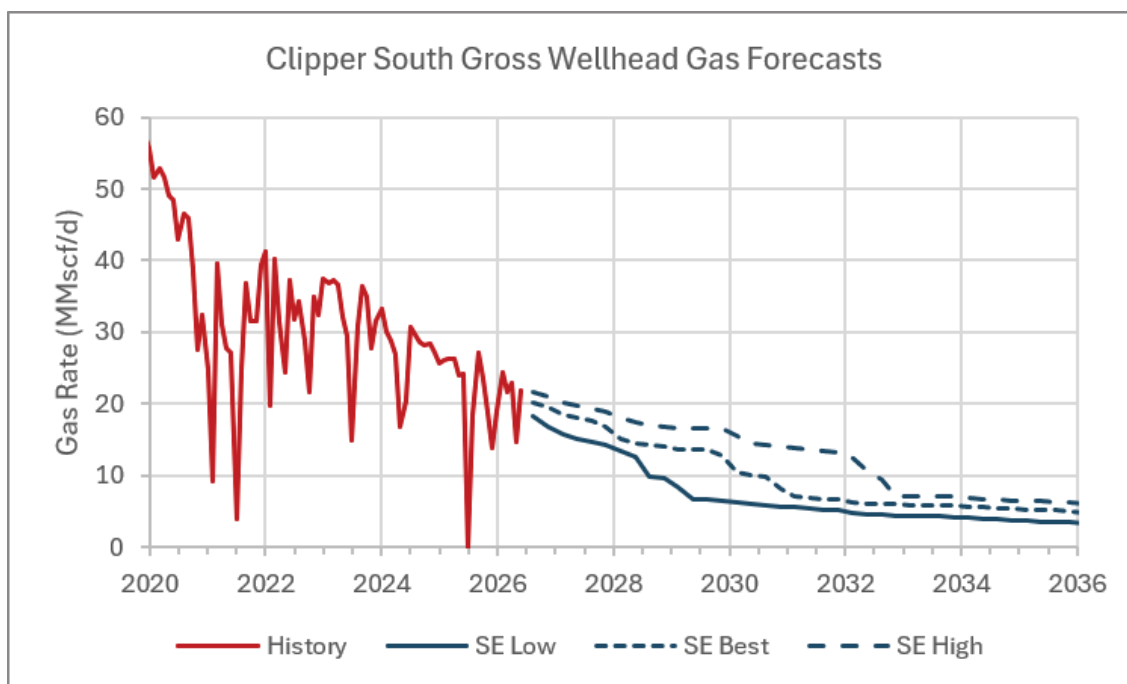


Figure 8.4: Clipper South gross wellhead gas production forecasts

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 (Dvdp+Undvdp)	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.

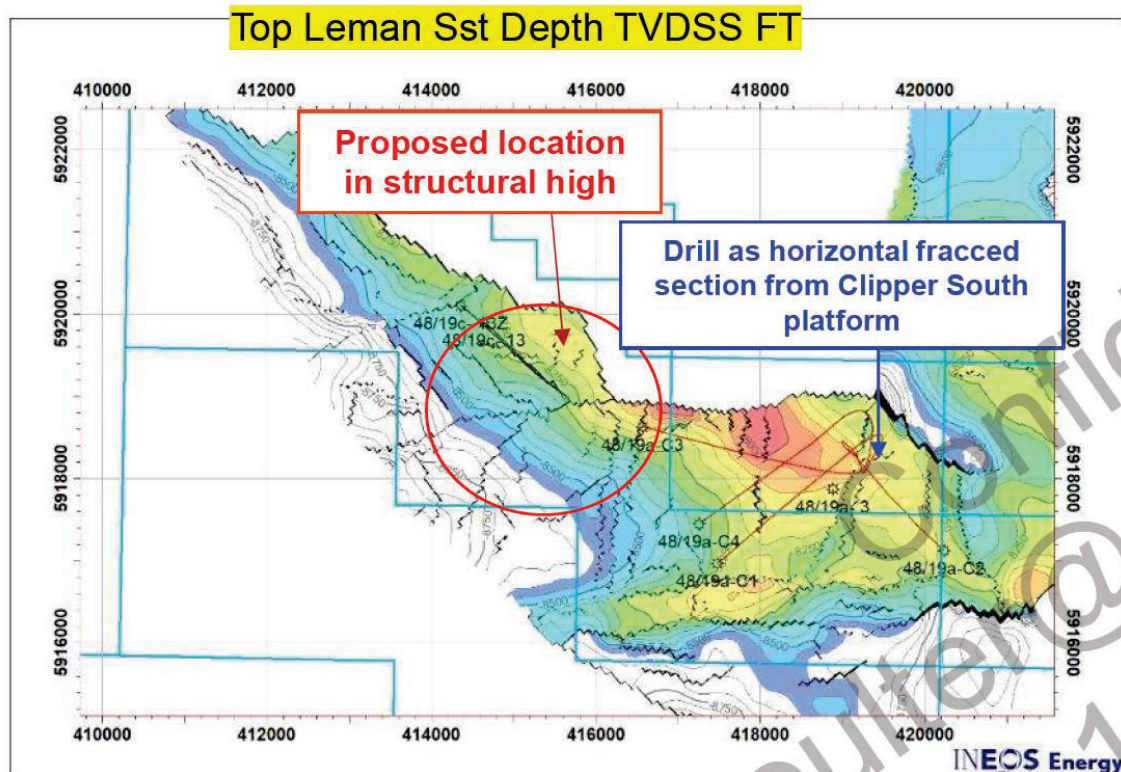


Figure 8.5: NW Clipper South area and proposed 5th well region

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.

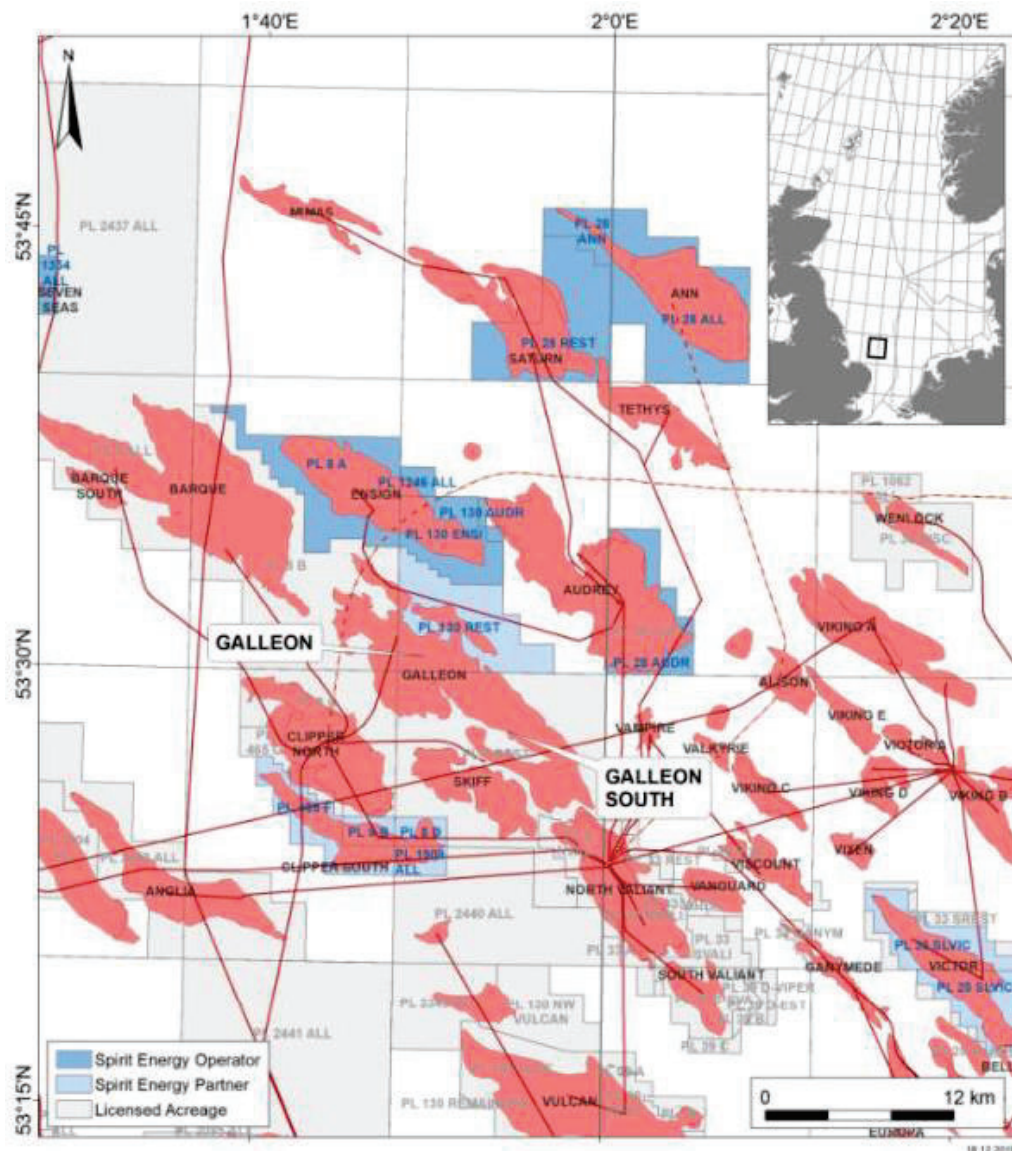


Figure 9.1: Galleon field location map

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.

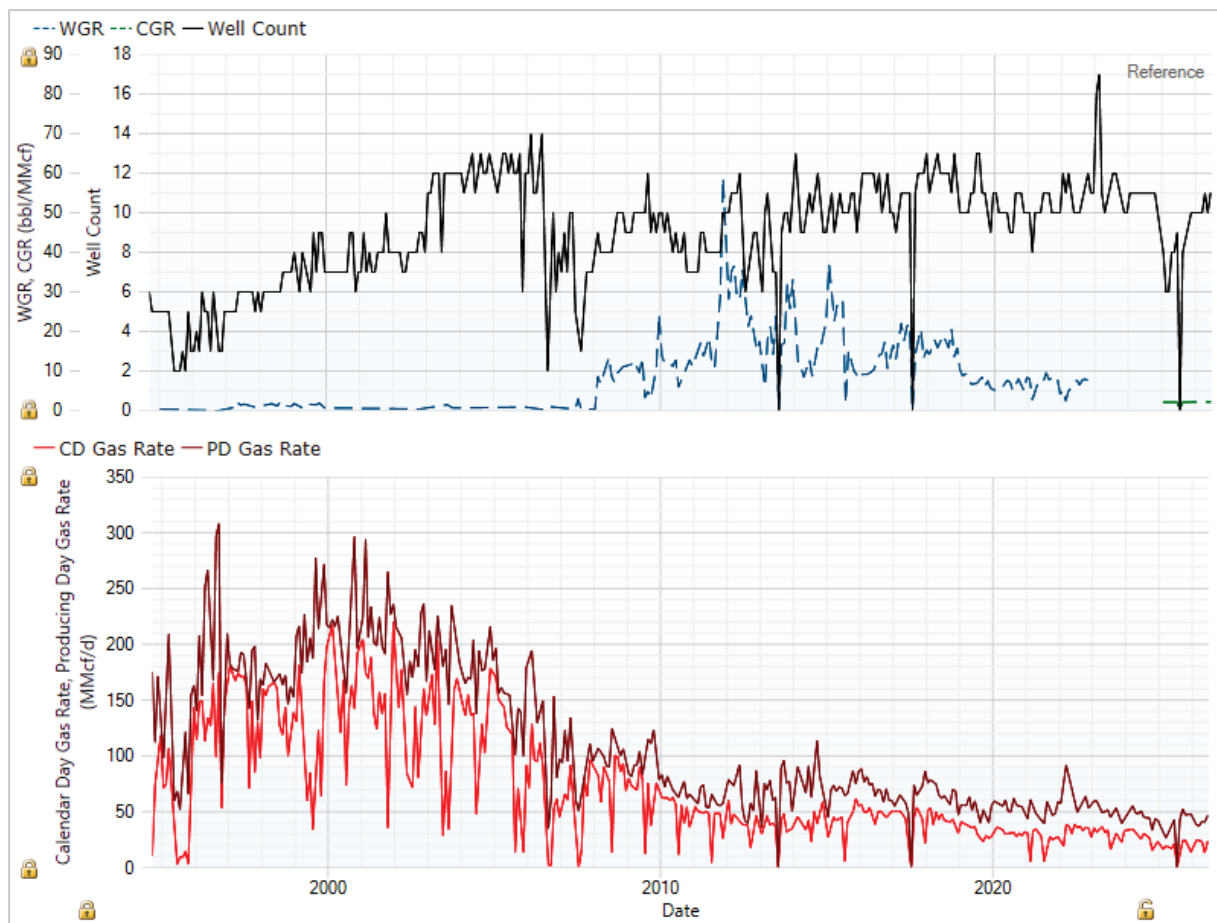


Figure 9.2: Galleon Field gas production history

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.

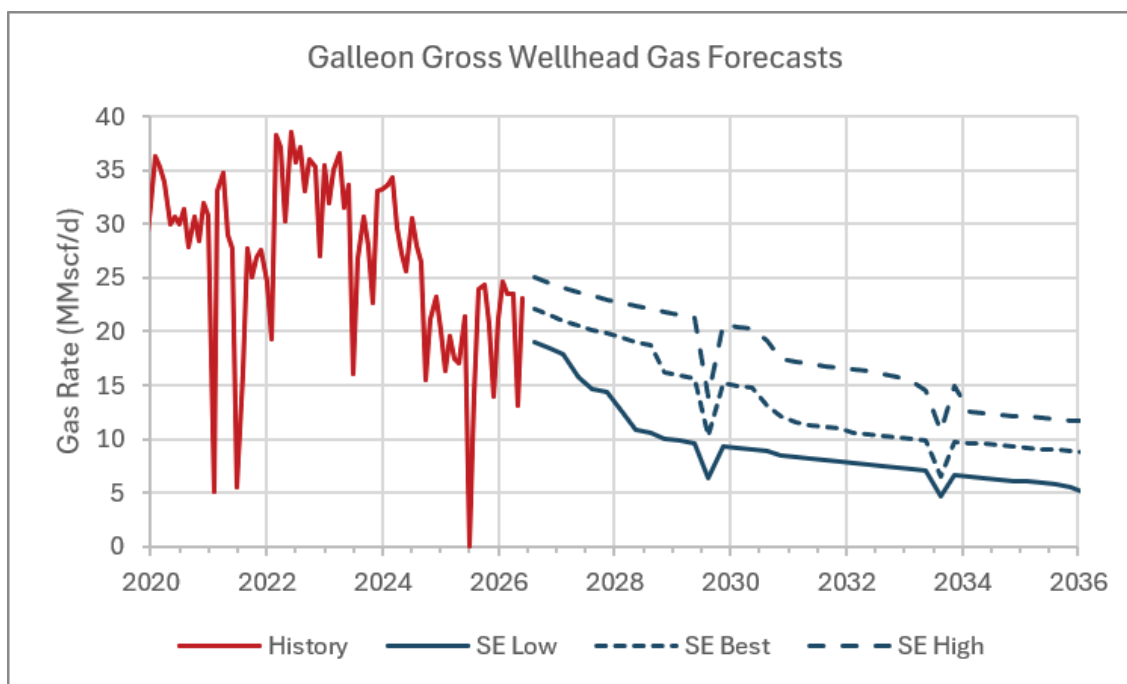


Figure 9.3: Galleon gross wellhead gas production forecasts

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.

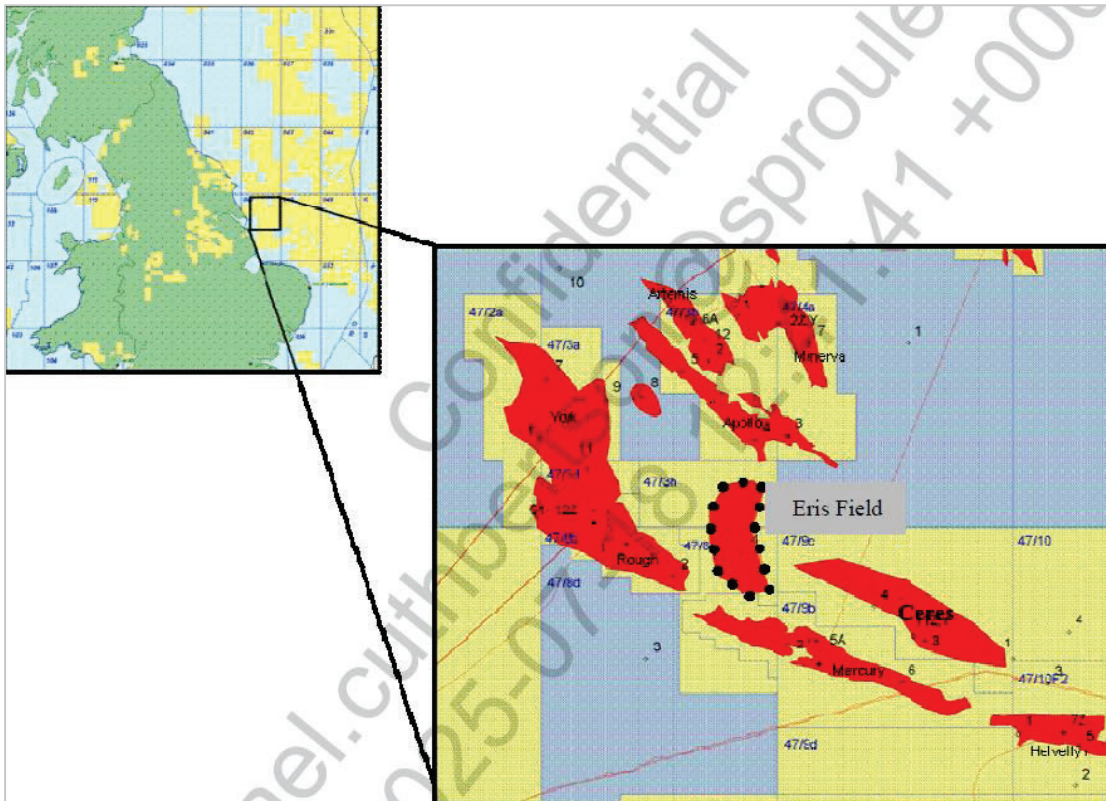


Figure 10.1: Eris field location map

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.

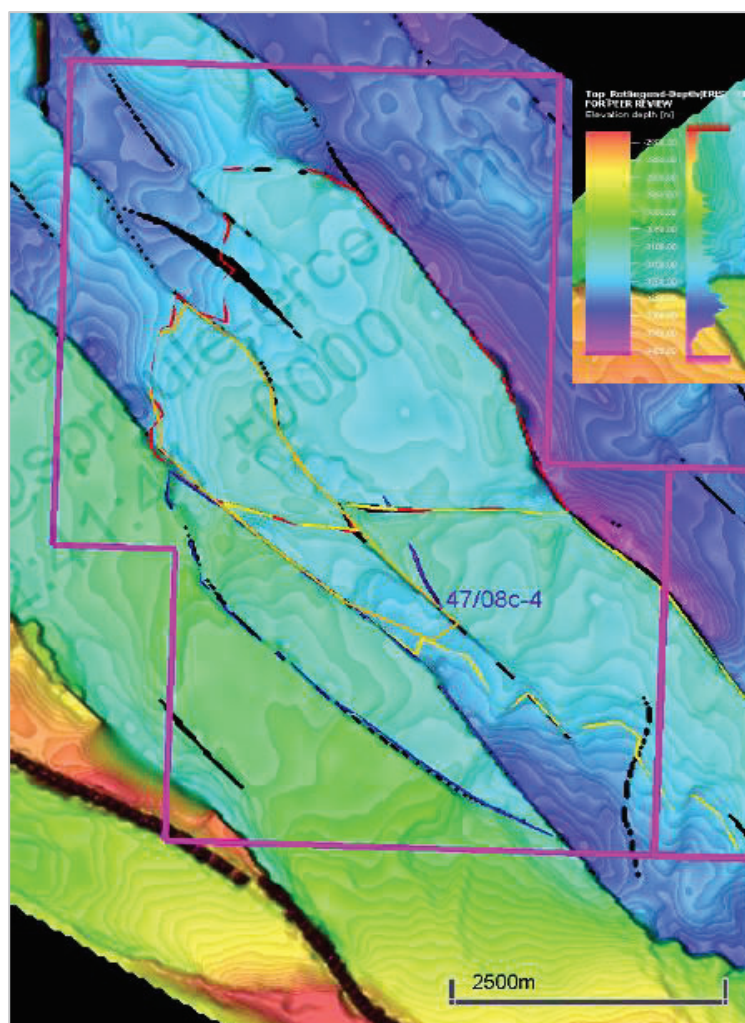


Figure 10.2: Eris Field top structure map

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.

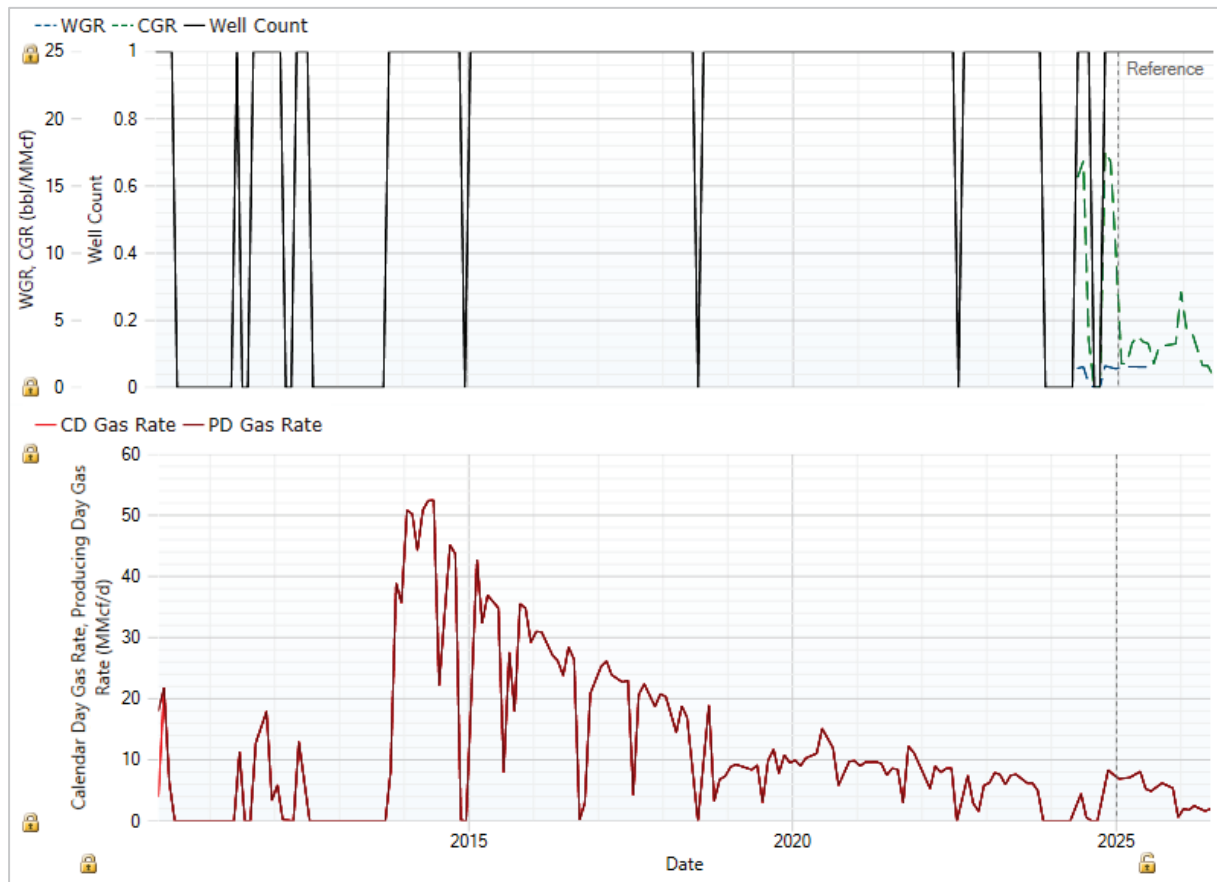


Figure 10.3: Eris Field production history

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.

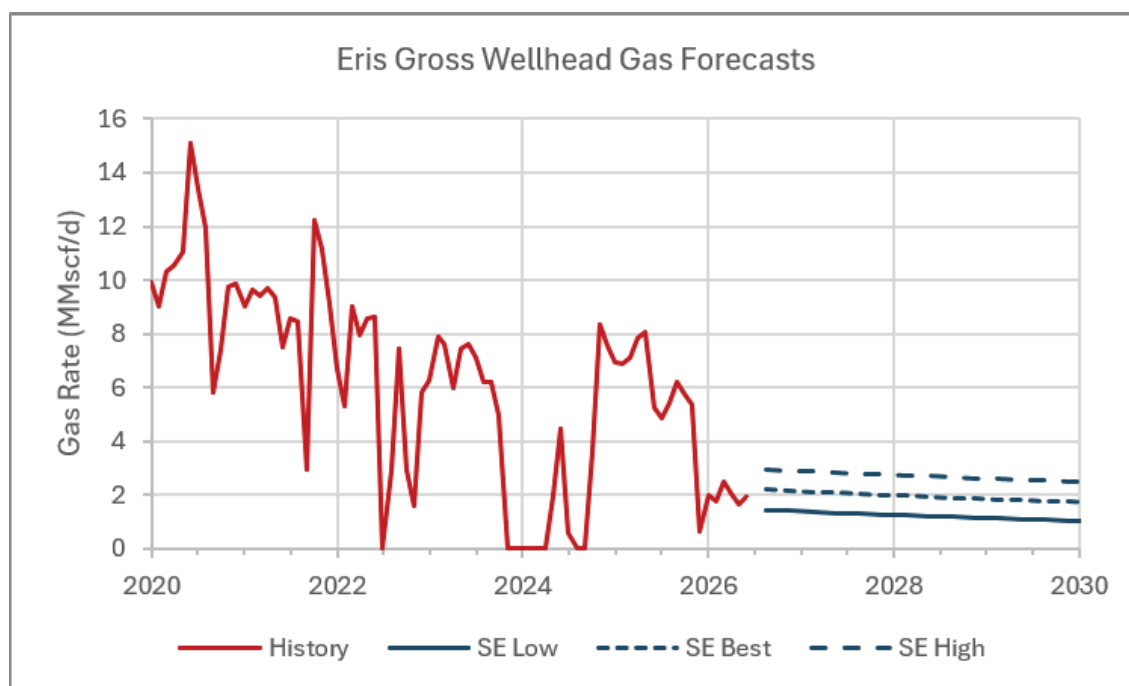


Figure 10.4: Eris gross wellhead gas production forecasts

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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
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)	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	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)	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	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)	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	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.04	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.05	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.06	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.02	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.4	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.4	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.4	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)	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	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	-	16.0	-	-	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.04	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.04	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)	OPEX (Real)	Dynamic ABEX Year	ABEX (Real)
	Oil	Gas	NGL				
	Mstb/d	MMscf/d	Mbbl/d	MM GBP	MM GBP		MM GBP
2026 H2	0.05	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

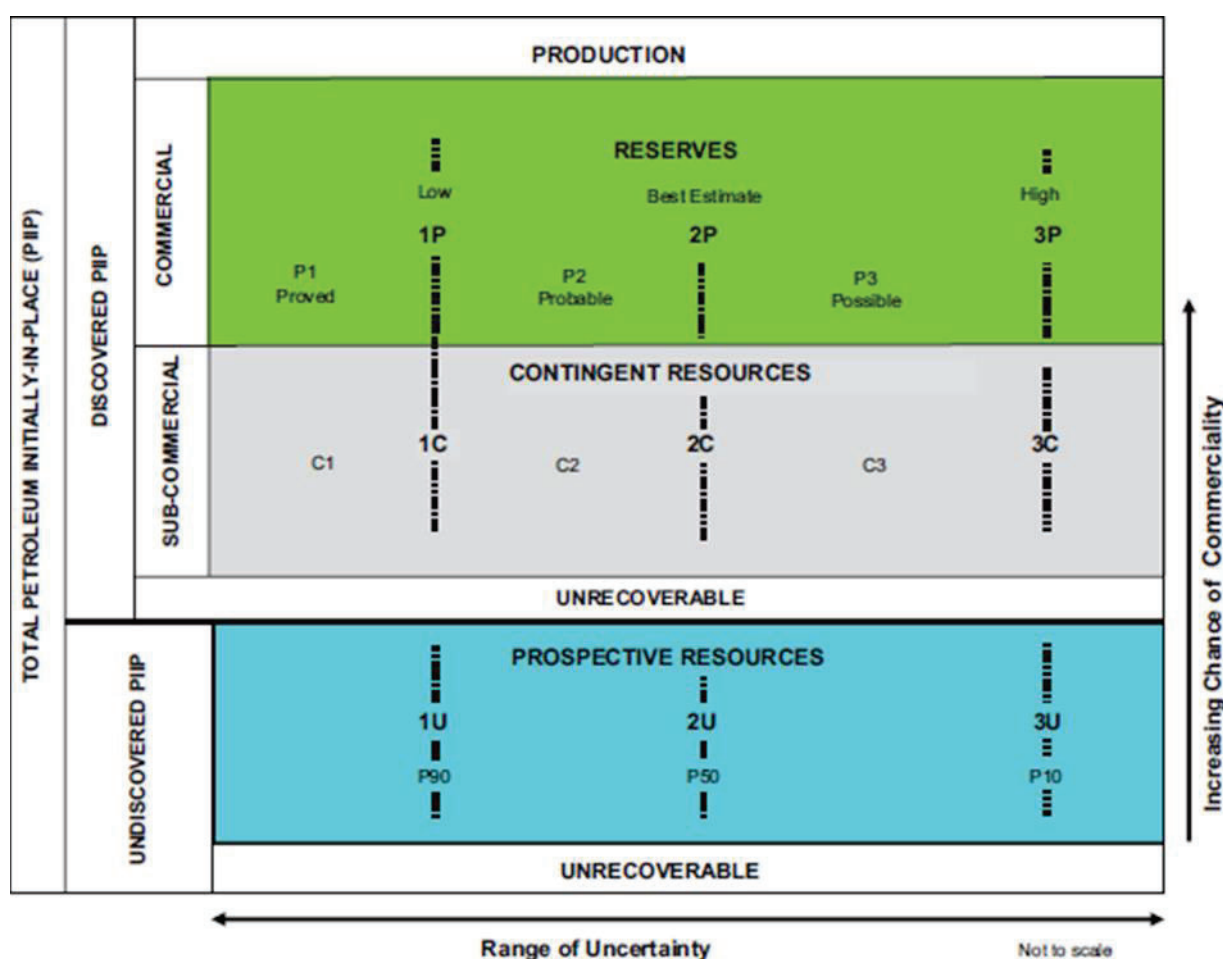
The table below identifies the categories that form the basis of our classification of reserves, resources and values presented in this report. The definitions used in this report are those set out in the Petroleum Resources Management System (SPE-PRMS) as sponsored by Society of Petroleum Engineers (“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.

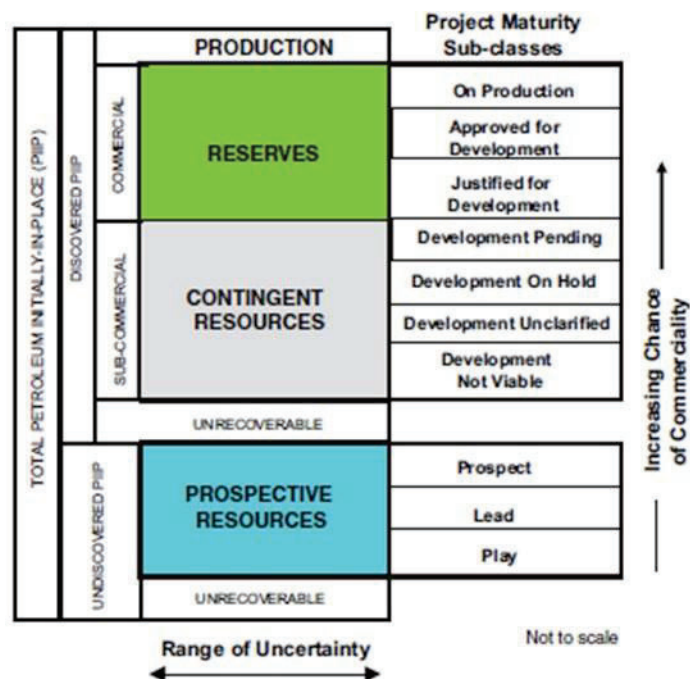
17. **Chance of Commerciality** is the product of the chance of geologic discovery and the chance of development and is used to estimate risk resources by multiplying with the resource volumes. The chance of geologic discovery for Contingent Resources is 100 percent, thus the Chance of Commerciality 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 or 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	STOIIP	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		

