This document comprises a simplified prospectus under Article 14 of the UK version of Regulation (EU) 2017/1129 which forms part of UK law by virtue of the European Union (Withdrawal) Act 2018 as amended (the "**UK Prospectus Regulation**") relating to Diversified Energy Company PLC (the "**Company**") prepared in accordance with the UK Prospectus Regulation Rules of the Financial Conduct Authority (the "**FCA**") made under section 73A of the Financial Services and Market Act 2000, as amended ("**FSMA**"). This document has been drawn up as a simplified prospectus in accordance with Article 14 of the UK Prospectus Regulation and has been approved by the FCA (as competent authority under the UK Prospectus Regulation). The FCA only approves this document as meeting the standards of completeness, comprehensibility and consistency imposed by the UK Prospectus Regulation. 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. Investors should make their own assessment as to the suitability of investing in the ordinary shares of £0.20 each in the capital of the Company (the "**Ordinary Shares**"). This document has been filed with the FCA in accordance with the Prospectus Regulation Rules and will be made available to the public in accordance with UK Prospectus Regulation Rule 3.2.1 by the same being made available, free of charge, at https://ir.div.energy/.

The Company has issued 8,500,000 new Ordinary Shares in connection with a capital raise (the "**Equity Raise Shares**") and, subject to certain conditions, may issue up to a further 850,000 new Ordinary Shares in connection the over-allotment option granted by the Company (the "**Over-Allotment Shares**" and together with the Equity Raise Shares, the "**Capital Raise Shares**"). The Company is also proposing, subject to certain conditions, to issue up to 33,954,491 new Ordinary Shares (the "**Consideration Shares**", and together with the Capital Raise Shares, the "**New Shares**") in connection with the acquisition of Maverick Natural Resources, LLC (the "**Acquisition**", and together with the Capital Raise, the "**Transactions**").

Applications will be made to the Financial Conduct Authority for admission of the New Shares to the equity shares (commercial companies) category of the Official List and to the London Stock Exchange plc for all the New Shares for admission to trading on the London Stock Exchange's Main Market for listed securities.

This prospectus 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 Ordinary Shares.

The Company and the Directors, whose names appear on page 46 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.

DIVERSIFIED
energy

DIVERSIFIED ENERGY COMPANY PLC

(Incorporated in England and Wales under the Companies Act 2006 with registered no. 09156132)

Admission of up to 43,468,171 New Shares to the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange's Main Market for listed securities

Sponsor

Stifel Nicolaus Europe Limited

The Ordinary Shares are admitted to listing on the equity shares (commercial companies) category of the Official List and to trading on the Main Market of the London Stock Exchange. Applications will be made for the New Shares to be admitted to listing on the equity shares (commercial companies) category of the Official List and to trading on the Main Market of the London Stock Exchange (the "**LSE**"). The Ordinary Shares are also listed and traded on the New York Stock Exchange ("**NYSE**") and it is expected that the New Shares will also be listed on the NYSE.

It is anticipated that (i) the Equity Raise Shares will be listed on the NYSE at approximately 2:30 p.m. (London time) on 21 February 2025 and admission of the Equity Raise Shares will become effective and that dealings in the Equity Raise Shares will commence on the LSE at approximately 8.00 a.m. (London time) on or around 24 February 2025 ("**Equity Raise Shares Admission**"), and (ii) the Over-Allotment Shares (if allotted and issued) will be listed on the NYSE and admission of the Over-Allotment Shares will become effective as soon as possible, and no later than within one month, after allotment of the Over-Allotment Shares (if any) ("**Over-Allotment Shares Admission**"), and (iii) the Consideration Shares will be listed on the NYSE, and admission of the Consideration Shares will become effective and dealings in the Consideration Shares will commence on the LSE ("**Consideration Shares Admission**", and together with the Equity Raise Shares Admission and the Over-Allotment Shares Admission, the "**New Shares Admission**") immediately following Completion, expected to be in H1 2025. No application has been made or is currently intended to be made for the New Shares to be admitted to listing or dealt on any other exchanges. The New Shares will, when issued, rank *pari passu* with each other and with all Ordinary Shares and will rank in full for all dividends and other distributions thereafter declared, made or paid in respect of the Ordinary Shares.

The whole of the text of this document should be read in its entirety. Your attention is also drawn, in particular, to the section headed "*Risk Factors*" at the beginning of this document which sets out certain risks and other factors that should be taken into account by investors. YOU SHOULD NOT RELY SOLELY ON INFORMATION SUMMARISED IN THE SECTION OF THIS DOCUMENT ENTITLED "SUMMARY".

Notice to US Shareholders

In connection with the Capital Raise, the Company has filed relevant materials with the US Securities and Exchange Commission (the "**SEC**"), including a shelf registration statement on Form F-3, which was filed on 11 February 2025 and became effective upon filing, and a prospectus supplement, which was filed on 20 February 2025 (together, the "**Registration Statement**") for the registration of the offer and sale of the Capital Raise Shares under the Securities Act of 1933, as amended (the "**US Securities Act**") by a foreign private issuer (as defined under the U.S. Securities Exchange Act of 1934, as amended) in the United States. For more information on the Capital Raise, investors should read the Registration Statement, together with all other relevant documents filed with the SEC. Shareholders may obtain the Registration Statement free of charge at the SEC's website, https://www.sec.gov, or for free from the Company at https://ir.div.energy/. Following completion of the Acquisition, the Company will file a Registration Statement on Form F-3 with the SEC to cover future sales by holders of the Consideration Shares.

Non-solicitation

This prospectus shall not constitute an offer to sell or the solicitation of an offer to buy any securities under the US federal securities laws, nor shall there be any sale of securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction. No offering of securities shall be made except by means of a prospectus meeting the requirements of section 10 of the US Securities Act.

General Notice

Stifel Nicolaus Europe Limited ("**Stifel**"), which is authorised and regulated in the United Kingdom by the FCA, is acting as sponsor exclusively for the Company and no one else in connection with the New Shares Admission and it will not regard any other person (whether or not a recipient of this document) as a client in relation to the New Shares Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice as sponsor in relation to the New Shares Admission or any other transaction, matter, or arrangement referred to in this document.

Apart from the responsibilities and liabilities, if any, which may be imposed on Stifel by FSMA or the regulatory regime established thereunder or under the regulatory regime of any other applicable jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, neither Stifel nor any of its affiliates accepts any responsibility whatsoever for the contents of this document including its accuracy, completeness and verification or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company or its Group, the Ordinary Shares or the New Shares Admission. Stifel and its affiliates accordingly disclaim, to the fullest extent permitted by applicable law, all and any liability whether arising in tort, contract or otherwise (save as referred to above) which they might otherwise be found to have in respect of this document or any such statement. No representation or warranty, express or implied, is made by Stifel or any of its affiliates as to the accuracy, completeness, verification or sufficiency of the information set out in this document, and nothing in this document will be relied upon as a promise or representation in this respect, whether or not to the past or future.

Stifel or its affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for the Company, for which they would have received customary fees. Stifel or its affiliates may provide such services to the Company and any of its affiliates in the future.

The distribution of this document in certain jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restrictions in relation to the Ordinary Shares or this document, including those in the paragraphs that follow. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. Except in the United Kingdom, no action has been taken or will be taken in any jurisdiction that would permit possession or distribution of this document in any country or jurisdiction where action for that purpose is required. Accordingly, this document may not be distributed or published in any jurisdiction where to do so would breach any securities laws or regulations of any such jurisdiction or give rise to an obligation to obtain any consent, approval or permission, or to make any application, filing or registration. Failure to comply with these restrictions may constitute a violation of the securities laws or regulations of such jurisdictions.

The contents of this document must not to be construed as legal, business or tax advice. Each prospective investor should consult his or her own lawyer, independent financial adviser or tax adviser for legal, financial or tax advice in relation to any dealing or proposed dealing in Ordinary Shares. Investors must inform themselves as to: (i) the legal requirements within their own countries for the purchase, holding, transfer, redemption or other disposal of Ordinary Shares; (ii) any foreign exchange restrictions applicable to the purchase, holding, transfer or other disposal of Ordinary Shares which they might encounter; and (iii) the income and other tax consequences which may apply in their own countries as a result of the purchase, holding, transfer or other disposal of Ordinary Shares. Investors must rely on their own representatives, including their own legal advisers, financial advisers, tax advisers and accountants, as to legal, financial, business, investment, tax, or any other related matters concerning the Company and an investment therein. None of the Company and/or Stifel nor any of their respective representatives is making any representation to any purchaser of Ordinary Shares regarding the legality of an investment in the Ordinary Shares by such purchaser under the laws applicable to such offeree or purchaser.

Subject to the FSMA, the Listing Rules, the UK Prospectus Regulation Rules, and the DTRs, the delivery of this document shall not, 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 as at any time after this date.

The Company will publish a supplement to this prospectus if a significant new factor, material mistake or material inaccuracy relating to the information in this document that may affect the assessment of the securities and which arises or is noted between the time when the document was approved and the date that is the latest of the Equity Raise Shares Admission, the Over-Allotment Shares Admission and Consideration Shares Admission. This document and any supplement will be made public in accordance with the UK Prospectus Regulation by publication on the Company's website at https://ir.div.energy/.

Unless expressly stated otherwise, references to an EU regulation shall be to that regulation as it forms part of the law of England and Wales by virtue of the European Union (Withdrawal) Act 2018 (as amended) and as the law of England and Wales is amended or re-enacted as at the date of this document.

Without limitation, the contents of the Group's websites (other than the information as set out in Part 8 ("*Documents Incorporated by Reference*")), or of any website accessible via hyperlinks from the Group's websites, do not form part of this document.

This document is dated 20 February 2025.

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SUMMARY

Part 1
INTRODUCTION

This summary should be read as an introduction to this document. Any decision to invest in the securities of the Company 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 including any translation thereof, 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.

The legal name of the Company is Diversified Energy Company PLC. The Company's registered office is at 4th Floor Phoenix House, 1 Station Hill, Reading, Berkshire, United Kingdom, RG1 1NB and its LEI is 213800YR9TFRVHPGOS67.

The Ordinary Shares are registered with International Securities Identification Number ("**ISIN**") GB00BQHP5P93 and trade under the symbol "DEC".

This document has been approved in accordance with the Prospectus Regulation on 20 February 2025 by the UK Financial Conduct Authority (the "**FCA**"), as competent authority, having its head office at 12 Endeavour Square, London, E20 1JN and telephone number +44 (0)20 7066 1000.

Part 2
KEY INFORMATION ON THE ISSUER

Who is the issuer of the securities?

The Company is the issuer of the Ordinary Shares. The Company is a public limited company incorporated in England operating under the Companies Act 2006, as amended and subordinate legislation thereunder (the "**Companies Act 2006**"). The Company's LEI is 213800YR9TFRVHPGOS67.

The Company is a leading independent energy company focused on natural gas and liquids production, transportation, marketing and well retirement, primarily located within the Appalachian and Central regions of the United States. The Appalachian Basin spans Pennsylvania, Virginia, West Virginia, Kentucky, Tennessee and Ohio and consists of multiple productive, shallow conventional formations and two productive, deeper unconventional shale formations, the Marcellus Shale and the slightly deeper Utica Shale. The Company also operates in the Bossier and Haynesville shale formations and the Cotton Valley sandstones in East Texas and West Louisiana, the Barnett Shale in North Texas and the Mid-Continent producing areas across Oklahoma and Texas.

The Company was incorporated in 2014 in the United Kingdom, and the Group's predecessor business was co-founded in 2001 by the Chief Executive Officer, Robert Russell "Rusty" Hutson, Jr., with an initial focus primarily on natural gas and oil production in West Virginia. In recent years, the Group has grown rapidly by capitalising on opportunities to acquire and enhance producing assets and by leveraging the operating efficiencies that result from economies of scale and vertical integration. As of 30 June 2024, the Group had completed 25 acquisitions since 2017 for a combined purchase price of approximately $3 billion.

There is no offer of the Company's securities.

Major interests in Ordinary Shares

As at the Latest Practicable Date, insofar as is known to the Company, the following persons are interested in 3 per cent. or more of the Company's voting rights:

Shareholder	Ordinary Shares held at the Latest Practicable Date	Percentage of Ordinary Share capital at the Latest Practicable Date(%)
BlackRock	4,936,644	9.62
Columbia Management Investment Advisers	3,654,367	7.12
Jupiter Asset Management	2,792,978	5.44
Maverick Natural Resources	2,342,445	4.57
Hargreaves Lansdown, stockbrokers (EO)	2,126,842	4.15
Interactive Investor (EO)	2,077,014	4.05
M&G Investments	1,754,311	3.42
Vanguard Group	1,593,364	3.11

Directors

The directors of the Company are: David Edward Johnson (*Independent Non-executive Chair*) Robert Russell "Rusty" Hutson, Jr. (*Chief Executive Officer*), Martin Keith Thomas (*Independent Non-executive Director*), David Jackson Turner, Jr. (*Independent Non-executive Director*), Sandra (Sandy) Mary Stash (*Independent Non-executive Director and Senior Independent Director*) and Kathryn Z. Klaber (*Independent Non-executive Director*).

Statutory Auditors

The Company's statutory auditor for the year ended 31 December 2023 was PricewaterhouseCoopers LLP, 1 Embankment Place, London, WC2N 6RH, United Kingdom. PricewaterhouseCoopers LLP is a member firm of the Institute of Chartered Accountants in England and Wales and has no material interest in the Company.

What is the key financial information regarding the issuer?

Group

The tables below set out selected key financial information for the Group. 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 2023 and the unaudited interim condensed consolidated financial statements of the Group as at and for the six-month period ended 30 June 2024 (the "**Group Financial Statements**").

Selected Consolidated Income Statement Data

	Six months ended 30 June		Year ended 31 December	
	2024	2023	2023	2022
	(unaudited)	(unaudited)		
	In US$ '000 (except earnings per ordinary share)			
Revenue	368,674	487,305	868,263	1,919,349
Gross profit	53,342	144,970	203,155	1,251,199
Net income/(loss) after tax	15,745	630,932	759,701	(620,598)
Period on period growth in revenue	(24%)		(55%)	
Earnings per ordinary share (basic) ($)	0.32	13.60	16.07	(14.82)
Earnings per ordinary share (diluted) ($)	0.32	13.43	15.95	(14.82)

Selected Consolidated Balance Sheet Data

	As at 30 June	As at 31 December	
	2024	2023	2022
	(unaudited)		
		In US$ '000	
Total assets	3,816,463	3,474,022	3,830,928
Total equity	548,298	598,410	(137,724)
Total liabilities	3,268,165	2,875,612	3,968,652

Selected Consolidated Cash Flow Data

	Six months ended 30 June		Year ended 31 December	
	2024	**2023**	**2023**	**2022**
	(unaudited)	**(unaudited)**		
	In US$ '000			
Net cash provided by operating activities	160,810	172,566	410,132	387,764
Net cash used in investing activities	(183,648)	(250,017)	(239,369)	(386,457)
Net cash provided by financing activities	22,568	74,330	(174,339)	(6,536)

There are no qualifications to the independent auditor's report included in the Group's annual report for the financial year ended 31 December 2023 or the independent review report for the six-month period ended 30 June 2024.

Maverick Group

The tables below set out selected key financial information for the Maverick Group. The financial information has been extracted without material adjustment from the audited consolidated financial statements of the Maverick Group as at and for the year ended 31 December 2023 and the unaudited interim condensed consolidated financial statements of the Maverick Group as at and for the nine-month period ended 30 September 2024.

Selected Consolidated Statement of Operations Data

	Nine months ended 30 September		Year ended 31 December	
	2024	**2023**	**2023**	**2022**
	(unaudited)	**(unaudited)**		
	In US$ '000			
Total revenues and other income items	635,480	707,744	1,123,324	1,181,003
Operating income (loss)	(11,931)	97,428	317,931	276,556
Income (loss) before taxes	(72,809)	56,460	256,885	251,677

Selected Consolidated Balance Sheet Data

	As at 30 September	As at 31 December	
	2024	**2023**	**2022**
	(unaudited)		
	In US$ '000		
Total assets	1,880,626	2,065,137	1,900,525
Members' equity	571,611	671,899	755,148
Total liabilities	1,309,015	1,393,238	1,145,376

Selected Consolidated Cash Flow Data

	Nine months ended 30 September		Year ended 31 December	
	2024	**2023**	**2023**	**2022**
	(unaudited)	**(unaudited)**		
	In US$ '000			
Net cash provided by operating activities	180,492	227,798	308,261	429,943
Net cash used in investing activities	(117,300)	(229,038)	(288,874)	(775,616)
Net cash provided by (used in) financing activities	(71,518)	(12,324)	49,006	266,664

Key Pro Forma Financial Information

The Pro Forma Financial Information only includes the impact of the Oaktree Transaction and the Acquisition. The Pro Forma Financial Information does not include other acquisitions, the Capital Raise, or any repayment of debt by the Company during the periods presented.

Unaudited Pro Forma Condensed Combined Statement of Financial Position as of 30 June 2024.

	DEC Historical	Maverick As Adjusted	Acquisition Adjustments	Pro Forma Combined
	(In US$ '000)			

Total assets	3,816,463	1,961,509	(129,420)	5,648,552
Total equity	548,298	588,425	(286,791)	849,932
Total liabilities	3,268,165	1,373,084	157,371	4,798,620

Unaudited Pro Forma Condensed Combined Statement of Operations for the six months ended 30 June 2024.

	DEC Historical	Oaktree Historical	Maverick As Adjusted	Oaktree Transaction Adjustments	Acquisition Adjustments	Pro Forma Combined
				(In US$ '000)		
Revenue	368,674	35,398	435,980	20,891	—	860,943
Gross profit	53,342	16,054	113,981	(2,548)	22,718	203,547
Operating profit (loss)	2,391	16,054	(37,139)	(2,548)	22,718	1,476
Net income (loss)	15,745	16,054	(84,253)	(14,483)	16,313	(50,624)

Unaudited Pro Forma Condensed Combined Statement of Operations for the year ended 31 December 2023

	DEC Historical	Oaktree Historical	Maverick As Adjusted	Oaktree Transaction Adjustments	Acquisition Adjustments	Pro Forma Combined
				(In US$ '000)		
Revenue	868,263	152,521	977,390	—	—	1,998,174
Gross profit	203,155	65,311	337,307	(38,720)	24,733	591,786
Operating profit (loss)	1,161,051	65,311	332,597	(38,720)	(25,212)	1,495,027
Net income (loss)	759,701	65,311	256,281	(68,974)	(53,057)	959,262

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

The key risks specific to the issuer are as follows:

(1) Volatility and future decreases in natural gas, NGLs and oil prices could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.
(2) The Group conducts its business in a highly competitive industry.
(3) The Group may experience delays in production, marketing and transportation.
(4) The Group faces production risks and hazards, including severe weather events, that may affect the Group's ability to produce natural gas, NGLs and oil at expected levels, quality and costs that may result in additional liabilities to the Group.
(5) The levels of the Group's natural gas and oil reserves and resources, their quality and production volumes may be lower than estimated or expected.
(6) The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations such as plugging.
(7) The Group may not be able to keep pace with technological developments in its industry or be able to implement them effectively.
(8) A lowering or withdrawal of the ratings, outlook or watch assigned to the Group or its debt by rating agencies may increase the Group's future borrowing costs and reduce its access to capital.
(9) Deterioration in the economic conditions in any of the industries in which the Group's customers operate, a domestic or worldwide financial downturn, or negative credit market conditions could have a material adverse effect on the Group's liquidity, results of operations, business and financial condition that it cannot predict.
(10) The Group's operations are subject to a series of risks relating to climate change.

Part 3
KEY INFORMATION ON THE SECURITIES

What are the main features of the securities?

The New Shares are ordinary shares of the Company of £0.20 each. The Ordinary Shares are admitted to trading on the Main Market for listed securities of the London Stock Exchange, registered with ISIN GB00BQHP5P93, Stock Exchange Daily Official List ("**SEDOL**") number BQHP5P9 and traded under the symbol "DEC" on the London Stock Exchange. The Ordinary Shares are listed and traded on the New York Stock Exchange ("**NYSE**") as well.

The rights attaching to the New Shares will be uniform in all respects with the Ordinary Shares, including with respect to the right to vote and the right to receive all dividends and other distributions declared, made or paid in respect of the Company's share capital after the Equity Raise Shares Admission, the Over-Allotment Shares Admission and Consideration Shares Admission, as applicable.

The Ordinary Shares are denominated in Pounds Sterling. The New Shares will be quoted and traded in Pounds Sterling on the London Stock Exchange and in US dollars on the NYSE.

As at the date of this document, the issued and outstanding share capital of the Company (excluding the Equity Raise Shares) is 51,295,942 Ordinary Shares of £0.20 each (all of which were fully paid). The Company has issued a further 8,500,000 new Ordinary Shares in connection with a capital raise (the "**Equity Raise Shares**") and, subject to certain conditions, may issue up to a further 850,000 new Ordinary Shares in connection the over-allotment option granted by the Company (the "**Over-Allotment Shares**" and together with the Equity Raise Shares, the "**Capital Raise Shares**") The Company is also proposing to issue up to 33,954,491 new Ordinary Shares of the Company (the "**Consideration Shares**", and together with the Capital Raise Shares, the "**New Shares**") in connection with the acquisition of Maverick Natural Resources, LLC (the "**Acquisition**", and together with the Capital Raise, the "**Transactions**").

Except as provided by the rights and restrictions attached to any class of shares, Shareholders will under general law be entitled to participate last in any surplus assets in a winding-up in proportion to the nominal value of their shareholdings.

Restrictions on free transferability of Ordinary Shares

There are no restrictions on the free transferability of the Ordinary Shares, other than certain transfer restrictions under: (i) the Companies Act 2006 for persons failing to respond to statutory notices issued by the Company requesting for information on interest in a particular holding of shares; (ii) the Articles, under which the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share in certain circumstances; and (iii) the relevant securities laws of the United States and certain other jurisdictions, as may be applicable to the transferor or the transferee.

Under the Articles, the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share which is not fully paid up but, in the case of a class of shares which has been admitted to the Official List of the FCA, not so as to prevent dealings in those shares from taking place on an open and proper basis or on which the Company has a lien. The Board may also refuse to register any instrument of transfer of a certificated share unless it is left (duly stamped) at the registered office, or such other place as the Board may decide, for registration, accompanied by the certificate for the shares to be transferred and such other evidence (if any) as the Board may reasonably require to prove title of the intending transferor or their right to transfer the shares; and it is in respect of only one class of shares and not in favour of more than four transferees.

Dividend policy

The Company has consistently declared dividends on the ordinary shares since its listing on the AIM Market of the LSE in 2017. The Board currently expects to declare a dividend of \$0.29 per share each quarter which equates to \$1.16 per year. This quarterly dividend payment, on an annualised basis, currently delivers a yield in the top quartile of the FTSE 250 share index and the top decile among the Russell 2000 Index. While the Board cannot provide assurance that the Company will be able to pay cash dividends on the Ordinary Shares in future periods, subject to certain restrictions, including those related to English law, and the terms of the Group's Credit Facility, for the financial year ended 31 December 2023, the Company paid a dividend of \$3.50 per Ordinary Share and for the nine months ended 30 September 2024, the Company has paid dividends of an aggregate of approximately \$69 million.

Under English law, among other things, the Company may only pay dividends if it has sufficient distributable reserves, which are the Company's accumulated realised profits that have not been previously distributed or capitalised less the Company's accumulated realised losses, so far as such losses have not been previously written off in a reduction or reorganisation of capital. In addition, the Company's ability to pay dividends is limited by restrictions under the terms of certain of its credit facilities. For example, the Group's Credit Facility contains a restricted payment covenant that limits the Group's subsidiaries' ability to make certain payments, based on the pro forma effect thereof on certain financial ratios.

The Board has not adopted, and does not currently intend to adopt, a formal written Company shareholder dividend policy and the Directors may revise the Group's dividend strategy from time to time in line with the actual results and financial position of the Group.

Where will the securities be traded?

Applications will be made to the London Stock Exchange for all of the New Shares to be admitted to trading on the London Stock Exchange's Main Market for listed securities. Application will be made for the New Shares to be approved for listing on the NYSE. No application has been made or is currently intended to be made for the New Shares to be admitted to listing or trading on any other exchanges.

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

The key risks specific to the securities are as follows:

(1) The price of Ordinary Shares may be volatile and purchasers of the Ordinary Shares could incur substantial losses.
(2) Shareholders may be subject to US withholding or income tax depending on their country of residence and their ownership percentages.
(3) The Group incurs increased costs as a result of operating as a public company in the United States, and the Group's management devote substantial time to new compliance initiatives and corporate governance practices following the NYSE listing.
(4) There is no guarantee that the Company will continue to pay dividends in the future.
(5) New Shares Admission may not occur when expected or an active trading market for the New Shares may not develop following New Shares Admission.

Part 4
KEY INFORMATION ON THE OFFER AND/OR THE ADMISSION TO TRADING ON A REGULATED MARKET

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

This Prospectus does not constitute an offer or invitation to any person to subscribe for or purchase any Ordinary Shares in the Company. It is currently expected that admission of the Equity Raise Shares to trading on the London Stock Exchange's Main Market for listed securities will become effective at 8.00 a.m. (London time) on or around 24 February 2025 and admission of the Over-Allotment Shares (if allotted and issued) will become effective as soon as possible, and no later than within one month, after allotment of the Over-Allotment Shares (if any) (together, the "**Capital Raise Shares Admission**") and admission of the Consideration Shares to trading on the London Stock Exchange's Main Market for listed securities will become effective (the "**Consideration Shares Admission**", and together with the Capital Raise Shares Admission, the "**New Shares Admission**") immediately following Completion, expected to be in H1 2025.

Who is the offeror and/or the person asking for admission to trading?

The Company will apply to the London Stock Exchange for all of the New Shares to be admitted to trading on the London Stock Exchange's Main Market for listed securities.

Why is this document being produced?

The Prospectus is being produced in connection with the New Shares Admission only. This Prospectus does not constitute an offer or invitation to any person to subscribe for or purchase any Ordinary Shares in the Company.

Reasons for the Capital Raise

The Company has issued 8,500,000 new Ordinary Shares in connection with the Capital Raise and, subject to certain conditions, may issue up to a further 850,000 new Ordinary Shares in connection the Over-Allotment Option granted by the Company. The Directors intend to use the net proceeds from the Capital Raise to repay a portion of the debt incurred by the Group in connection with the Acquisition. In the event that the Acquisition does not close, the Company intends to use the net proceeds from the Capital Raise for repayment of debt and general corporate purposes.

In connection with the Capital Raise in the United States, the Company has filed relevant materials with the U.S. Securities and Exchange Commission ("**SEC**"), including a shelf registration statement on Form F-3 under the US Securities Act, which was filed on 11 February 2025 and became effective upon filing, and a prospectus supplement, which was filed on 20 February 2025 (together, the "**Registration Statement**"), and has applied to list the New Shares on the NYSE. The Equity Raise Shares are expected to be listed on the NYSE on or around 21 February 2025.

The Acquisition

The Company is also proposing, subject to certain conditions, to issue up to 33,954,491 new Ordinary Shares of the Company in accordance Article 1(4) of the UK Prospectus Regulation in connection with the Acquisition. Following completion of the Acquisition, the Company will file a Registration Statement on Form F-3 with the SEC to cover future sales by holders of the Consideration Shares.

Material conflicts of interest

There are no conflicting interests which are material in connection with the Equity Raise Shares Admission, the Over-Allotment Shares Admission and/or the Consideration Shares Admission.

RISK FACTORS

Any investment in the Ordinary Shares is subject to a number of risks. Accordingly, Shareholders and prospective investors should carefully consider the factors and risks associated with any investment in the Ordinary Shares, the Group's business and the industry in which the Group operates, together with all other information contained in this document and all of the information incorporated by reference into this document, including, in particular, the risk factors described below, and their personal circumstances prior to making any investment decision.

The Group's business, results of operations, financial condition, cash flows or prospects could be materially and adversely affected by any of the risks described below. The risks relating to the Group, its industry and the Ordinary Shares summarised in the section of this document headed "Summary" are the risks that the Directors believe to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Ordinary Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in the section of this document headed "Summary" but also, among other things, the risks and uncertainties described below.

The risk factors described below are not an exhaustive list or explanation of all risks which investors may face when making an investment in the Ordinary Shares and should be used as guidance only. Additional risks and uncertainties relating to the Group that are not currently known to the Group, or that it currently deems immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. If any such risk, or any of the risks described below, should materialise, the price of the Ordinary Shares may decline and investors could lose all or part of their investment. 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.

Prospective investors should read this section in conjunction with this entire document (including the information incorporated into this document by reference).

RISKS RELATED TO THE GROUP'S BUSINESS AND INDUSTRY

Volatility and future decreases in natural gas, NGLs and oil prices could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

The Group's business, results of operations, financial condition, cash flows or prospects depend substantially upon prevailing natural gas, NGL and oil prices, which may be adversely impacted by unfavorable global, regional and national macroeconomic conditions, including but not limited to instability related to the military conflict in Ukraine. Natural gas, NGLs and oil 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 natural gas, NGLs and oil have fluctuated widely for many reasons, including:

- global and regional supply and demand, and expectations regarding future supply and demand, for gas and oil products;
- global and regional economic conditions;
- evolution of stocks of oil and related products;
- increased production due to new extraction developments and improved extraction and production methods;
- geopolitical uncertainty;
- threats or acts of terrorism, war or threat of war, which may affect supply, transportation or demand;
- weather conditions, natural disasters, climate change and environmental incidents;
- access to pipelines, storage platforms, shipping vessels and other means of transporting, storing and refining gas and oil, including without limitation, changes in availability of, and access to, pipeline ullage;

- prices and availability of alternative fuels;
- prices and availability of new technologies affecting energy consumption;
- increasing competition from alternative energy sources;
- the ability of OPEC and other oil-producing nations, to set and maintain specified levels of production and prices;
- political, economic and military developments in gas and oil producing regions generally;
- governmental regulations and actions, including the imposition of export restrictions and taxes and environmental requirements and restrictions as well as anti-hydrocarbon production policies;
- trading activities by market participants and others either seeking to secure access to natural gas, NGLs and oil or to hedge against commercial risks, or as part of an investment portfolio; and
- market uncertainty, including fluctuations in currency exchange rates, and speculative activities by those who buy and sell natural gas, NGLs and oil on the world markets.

It is impossible to accurately predict future gas, NGL and oil price movements. Historically, natural gas prices have been highly volatile and subject to large fluctuations in response to relatively minor changes in the demand for natural gas. According to the U.S. Energy Information Administration, the historical high and low Henry Hub natural gas spot prices for the following periods were as follows: in 2021, high of $23.86 and low of $2.43; in 2022, high of $9.85 and low of $3.46, and in 2023, high of $3.78 and low of $1.74 — highlighting the volatile nature of commodity prices.

The economics of producing from some wells and assets may also result in a reduction in the volumes of the Group's reserves which can be produced commercially, resulting in decreases to the Group's reported reserves. Additionally, further reductions in commodity prices may result in a reduction in the volumes of the Group's reserves. The Group might also elect not to continue production from certain wells at lower prices, or the Group's license partners may not want to continue production regardless of the Group's position.

Each of these factors could result in a material decrease in the value of the Group's reserves, which could lead to a reduction in the Group's natural gas, NGLs and oil development activities and acquisition of additional reserves. In addition, certain development projects or potential future acquisitions could become unprofitable as a result of a decline in price and could result in the Group postponing or canceling a planned project or potential acquisition, or if it is not possible to cancel, to carry out the project or acquisition with negative economic impacts. Further, a reduction in natural gas, NGL or oil prices may lead the Group's producing fields to be shut down and to be entered into the decommissioning phase earlier than estimated.

The Group's revenues, cash flows, operating results, profitability, dividends, future rate of growth and the carrying value of the Group's gas and oil properties depend heavily on the prices the Group receives for natural gas, NGLs and oil sales. Commodity prices also affect the Group's cash flows available for capital investments and other items, including the amount and value of the Group's gas and oil reserves. In addition, the Group may face gas and oil property impairments if prices fall significantly. In light of the continuing increase in supply coming from the Utica and Marcellus shale plays of the Appalachian Basin, no assurance can be given that commodity prices will remain at levels which enable the Group to do business profitably or at levels that make it economically viable to produce from certain wells and any material decline in such prices could result in a reduction of the Group's net production volumes and revenue and a decrease in the valuation of the Group's production properties, which could materially and adversely impact the Group's business, results of operations, financial condition, cash flows or prospects.

The Group conducts its business in a highly competitive industry.

The gas and oil industry is highly competitive. The key areas in which the Group faces competition include:

- engagement of third-party service providers whose capacity to provide key services may be limited;
- acquisition of other companies that may already own licenses or existing producing assets;
- acquisition of assets offered for sale by other companies;

- access to capital (debt and equity) for financing and operational purposes;
- purchasing, leasing, hiring, chartering or other procuring of equipment that may be scarce; and
- employment of qualified and experienced skilled management and gas and oil professionals and field operations personnel.

Competition in the Group's markets is intense and depends, among other things, on the number of competitors in the market, their financial resources, their degree of geological, geophysical, engineering and management expertise and capabilities, their degree of vertical integration and pricing policies, their ability to develop properties on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships with the relevant authorities. The cost to attract and retain qualified and experienced personnel has increased and may increase substantially in the future.

The Group's competitors also include those entities with greater technical, physical and financial resources than the Group. Finally, companies and certain private equity firms not previously investing in natural gas and oil may choose to acquire reserves to establish a firm supply or simply as an investment. Any such companies will also increase market competition which may directly affect the Group.

The effects of operating in a competitive industry may include:

- higher than anticipated prices for the acquisition of licenses or assets;
- the hiring by competitors of key management or other personnel; and
- restrictions on the availability of equipment or services.

If the Group is unsuccessful in competing against other companies, the Group's business, results of operations, financial condition, cash flows or prospects could be materially and adversely affected.

The Group may experience delays in production, transportation and marketing.

Various production, transportation and marketing conditions may cause delays in natural gas, NGLs and oil production and adversely affect the Group's business. For example, the gas gathering systems that the Group's owns connect to other pipelines or facilities which are owned and operated by third parties. These pipelines and other midstream facilities and others upon which the Group relies on may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage. In periods where NGL prices are high, the Group benefits greatly from the ability to process NGLs. The Group's largest processor of NGLs is the MarkWest Energy Partners, L.P., ("**MarkWest**") plant located in Langley, Kentucky. If the Group were to lose the ability to process NGLs at MarkWest's plant during a period of high pricing, the Group's revenues would be negatively impacted. As a short-term measure, the Group could divert the natural gas through other pipeline routes; however, certain pipeline operators would eventually decline to transport the gas due to its liquid content at a level that would exceed tariff specifications for those pipelines. The lack of available capacity on third-party systems and facilities could reduce the price offered for the Group's production or result in the shut-in of producing wells. Any significant changes affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay the Group's production, which could materially and adversely impact the Group's business, results of operations, financial condition, cash flows or prospects.

The Group faces production risks and hazards, including severe weather events, that may affect the Group's ability to produce natural gas, NGLs and oil at expected levels, quality and costs that may result in additional liabilities to the Group.

The Group's natural gas and oil production operations are subject to numerous risks common to its industry, including, but not limited to, premature decline of reservoirs, incorrect production estimates, invasion of water into producing formations, geological uncertainties such as unusual or unexpected rock formations and abnormal geological pressures, low permeability of reservoirs, contamination of natural gas and oil, blowouts, oil and other chemical spills, explosions, fires, equipment damage or failure, challenges relating to transportation, pipeline infrastructure, natural disasters, uncontrollable flows of oil, natural gas or well fluids, adverse and severe weather conditions, shortages of skilled labor, delays in obtaining regulatory approvals or consents, pollution and other environmental risks.

If any of the above events occur, environmental damage, including biodiversity loss or habitat destruction, injury to persons or property and other species and organisms, loss of life, failure to produce natural gas, NGLs and oil in commercial quantities or an inability to fully produce discovered reserves could result. These events could also cause substantial damage to the Group's property or the property of others and the Group's reputation and put at risk some or all of the Group's interests in licenses, which enable the Group to produce, and could result in the incurrence of 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 declines from normal field operating conditions and other adverse actions taken by third parties may result in revenue and cash flow levels being adversely affected.

Moreover, should any of these risks materialise, the Group could incur legal defense costs, remedial costs and substantial losses, including those due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, environmental damage, unplanned production outages, clean-up responsibilities, regulatory investigations and penalties, increased public interest in the Group's operational performance and suspension of operations, which could materially and adversely impact the Group's business, results of operations, financial condition, cash flows or prospects.

The levels of the Group's and the Maverick Group's natural gas and oil reserves and resources, their quality and production volumes may be lower than estimated or expected.

The reserves data contained in the 2023 Annual Report for the Group and the reserves data for the Maverick Group as set out in Part 5 (*Competent Persons Report for the Maverick Group*) have been audited by Netherland, Sewell & Associates, Inc. ("**NSAI**") unless stated otherwise. The standards utilised to prepare the reserves information that has been extracted in this document may be different from the standards of reporting adopted in other jurisdictions. Investors, therefore, should not assume that the data found in the reserves information set forth in the 2023 Annual Report and/or Part 5 (*Competent Persons Report for the Maverick Group*) is directly comparable to similar information that has been prepared in accordance with the reserve reporting standards of other jurisdictions.

In general, estimates of economically recoverable natural gas, NGLs and oil reserves are based on a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological, geophysical and engineering estimates (which have inherent uncertainties), historical production from the properties or analogous reserves, the assumed effects of regulation by governmental agencies and estimates of future commodity prices, operating costs, gathering and transportation costs and production related taxes, 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 economically recoverable natural gas and oil reserves, rates of production and, where applicable, the timing of development expenditures depend upon several variables and assumptions, including the following:

- production history compared with production from other comparable producing areas;
- quality and quantity of available data;
- interpretation of the available geological and geophysical data;
- effects of regulations adopted by governmental agencies;
- future percentages of sales;
- future natural gas, NGLs and oil prices;
- capital investments;
- effectiveness of the applied technologies and equipment;
- effectiveness of the Group's and/or the Maverick Group's field operations employees to extract the reserves;
- natural events or the negative impacts of natural disasters;

- future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs; and
- the judgment of the persons preparing the estimate.

As all reserve estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities and qualities that are ultimately recovered;
- the timing of the recovery of natural gas and oil reserves;
- the production and operating costs incurred;
- the amount and timing of development expenditures, to the extent applicable;
- future hydrocarbon sales prices; and
- decommissioning costs and changes to regulatory requirements for decommissioning.

Many of the factors in respect of which assumptions are made when estimating reserves are beyond the Group's and Maverick Group's control and therefore these estimates may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves evaluation depends on the quality of available information and natural gas, NGLs and oil engineering and geological interpretation. Furthermore, less historical well production data is available for unconventional wells because they have only become technologically viable in the past twenty years and the long-term production data is not always sufficient to determine terminal decline rates. In comparison, some conventional wells in the Group's and Maverick Group's portfolio have been productive for a much longer time. As a result, there is a risk that estimates of the Group's and Maverick Group's shale reserves are not as reliable as estimates of the conventional well reserves that have a longer historical profile to draw on.

Interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's and Maverick Group's reserves and resources data. Moreover, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves will vary from estimates and the variances may be material.

If the assumptions upon which the estimates of the Group's and/or Maverick Group's natural gas and oil reserves prove to be incorrect or if the actual reserves available to the Group and/or Maverick Group (or the operator of an asset in the Group and/or Maverick Group has an interest) 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 natural gas, NGLs or oil set out in this document and this may materially and adversely affect the Enlarged Group's business, results of operations, financial condition, cash flows or prospects.

The PV-10, will not necessarily be the same as the current market value of the Group's estimated natural gas, NGL and oil reserves. Investors should not assume that the present value of future net cash flows from the Group's and Maverick Group's reserves is the current market value of the Group's and Maverick Group's estimated natural gas, NGL and oil reserves. Actual future net cash flows from the Group's and Maverick Group's natural gas and oil properties will be affected by factors such as:

- actual prices it receives for natural gas, NGL and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- transportation and processing; and
- changes in governmental regulations or taxation.

The timing of both the Group's and Maverick Group's production and the Group's and Maverick Group's incurrence of expenses in connection with the development and production of the Group's and Maverick

Group's natural gas and oil properties will affect the timing and amount of actual future net cash flows from reserves, and thus their actual present value. In addition, the 10% discount factor the Group uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Group or the natural gas and oil industry in general. Actual future prices and costs may differ materially from those used in the present value estimate.

The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations such as plugging.

In the future, the Group may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which the Group uses for the processing of natural gas and oil reserves. With regards to plugging, the Group is a party to agreements with regulators in the states of Ohio, West Virginia, Kentucky and Pennsylvania, the Group's four largest wellbore states, setting forth plugging and abandonment schedules spanning a period ranging from 10 to 15 years. The Group will incur such decommissioning costs at the end of the operating life of some of the Group's properties. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, the shortage of plugging vendors, difficult terrain or weather conditions or experience at other production sites. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves, wells losing commercial viability sooner than forecasted or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The use of other funds to satisfy such decommissioning costs may impair the Group's ability to focus capital investment in other areas of the Group's business, which could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

The Group may not be able to keep pace with technological developments in its industry or be able to implement them effectively.

The natural gas and oil industry is characterised by rapid and significant technological advancements and introductions of new products and services using new technologies, such as emissions controls and processing technologies. Rapid technological advancements in information technology and operational technology domains require seamless integration. Failure to integrate these technologies efficiently may result in operational inefficiencies, security vulnerabilities, and increased costs.

During mergers and acquisitions, integrating technology assets from acquired companies can be complex. Poor integration may lead to data inconsistencies, security gaps and operational disruptions. Technology systems are also susceptible to cybersecurity threats, including malware, data breaches, and ransomware attacks. These threats may disrupt operations, compromise sensitive data and lead to significant financial losses. Further, inefficient data management practices may result in data breaches, data loss and missed opportunities for operational insights. The presence of legacy technology systems can also pose challenges, as they may lack modern security features, making them vulnerable to cyber threats and necessitating costly upgrades.

As others use or develop new technologies, the Group may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other natural gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, which may in the future allow them to implement new technologies before the Group can. Additionally, reliance on global supply chains for information technology hardware, software and operational technology equipment exposes the industry to supply chain disruptions, shortages and cybersecurity risks.

If one or more of the technologies used now or in the future were to become obsolete, the Group's business, results of operations, financial condition, cash flows or prospects could be materially and adversely affected if competitors gain a material competitive advantage.

A lowering or withdrawal of the ratings, outlook or watch assigned to the Group or its debt by rating agencies may increase the Group's future borrowing costs and reduce its access to capital.

The rating, outlook or watch assigned to the Group or its debt could be lowered or withdrawn entirely by a rating agency if, in that rating agency's judgment, current or future circumstances relating to the basis of the rating, outlook, or watch such as adverse changes to the Group's business, so warrant. The Group's credit ratings may also change as a result of the differing methodologies or changes in the methodologies used by the rating agencies. Any future lowering of the Group's debt's ratings, outlook or watch would likely make it more difficult or more expensive for the Group to obtain additional debt financing.

It is also possible that such ratings may be lowered in connection with the Group's dual listing or in connection with future events, such as future acquisitions. Holders of the Ordinary Shares will have no recourse against the Group or any other parties in the event of a change in or suspension or withdrawal of such ratings. Any lowering, suspension or withdrawal of such ratings could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

Deterioration in the economic conditions in any of the industries in which the Group's customers operate, a domestic or worldwide financial downturn, or negative credit market conditions could have a material adverse effect on the Group's liquidity, results of operations, business and financial condition that it cannot predict.

Economic conditions in a number of industries in which the Group's customers operate have experienced substantial deterioration in the past, resulting in reduced demand for natural gas and oil. Renewed or continued weakness in the economic conditions of any of the industries the Group serves or that are served by the Group's customers, or the increased focus by markets on carbon-neutrality, could adversely affect the Group's business, financial condition, results of operation and liquidity in a number of ways. For example:

- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of the Group's natural gas business;
- a decrease in international demand for natural gas or NGLs produced in the United States could adversely affect the pricing for such products, which could adversely affect the Group's results of operations and liquidity;
- the tightening of credit or lack of credit availability to the Group's customers could adversely affect the Group's liquidity, as the Group's ability to receive payment for its products sold and delivered depends on the continued creditworthiness of the Group's customers;
- the Group's ability to refinance its credit facility may be limited and the terms on which the Group is able to do so may be less favorable to the Group depending on the strength of the capital markets or the Group's credit ratings;
- the Group's ability to access the capital markets may be restricted at a time when it would like, or need, to raise capital for the Group's business including for exploration and/or development of the Group's natural gas reserves;
- increased capital markets scrutiny of oil and gas companies may lead to increased costs of capital or lack of credit availability; and
- a decline in the Group's creditworthiness may require it to post letters of credit, cash collateral, or surety bonds to secure certain obligations, all of which would have an adverse effect on the Group's liquidity.

The Group's operations are subject to a series of risks relating to climate change.

Continued public concern regarding climate change and potential mitigation through regulation could have a material impact on the Group's business. International agreements, national, regional, state and local legislation, and regulatory measures to limit GHG emissions are currently in place or in various stages of discussion or implementation. For example, the Inflation Reduction Act, which was signed into law in August 2022, includes a "methane fee" that is expected to be imposed beginning with emissions reported for calendar year 2024. In addition, the current U.S. administration has proposed more stringent methane pollution limits for new and existing gas and oil operations. Given that some of the Group's operations are associated with emissions of GHGs, these and other GHG emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted by particular countries, states, provinces and municipalities.

Additionally, regulatory, market and other changes to respond to climate change may adversely impact the Group's business, financial condition or results of operations. Reporting expectations are also increasing, with a variety of customers, capital providers and regulators seeking increased information on climate-related risks. For example, the SEC has adopted climate-related disclosures rules that may require the Group to incur significant costs to assess and disclose on a range of climate-related data and risks.

Internationally, the United Nations-sponsored "Paris Agreement" requires member nations to individually determine and submit non-binding emissions reduction targets every five years after 2020. In November 2021, the international community gathered in Glasgow at the 26th Conference of the Parties to the UN Framework Convention on Climate Change, during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. In January 2024, President Trump signed an executive order directing the United States to withdraw from the Paris Agreement and it is expected that President Trump and the Republican-led Congress will diverge from the previous administration's positions and GHG commitments. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. Such commitments were re-affirmed at the 27th Conference of the Parties in Sharm El Sheikh but it is expected that President Trump and the Republican-led Congress will not support the same. Following such directed and future withdrawals and rolling back of GHG commitments by the U.S. government, emission reduction targets and other provisions of legislative or regulatory initiatives and policies enacted in the future by the United States may still be possible or, in the absence of federal action, states in which the Group operates may become more active and focused on taking legislative or regulatory actions aimed at climate change and minimizing GHG emissions. This could adversely impact the Group's business by imposing increased costs in the form of higher taxes or increases in the prices of emission allowances, limiting the Group's ability to develop new gas and oil reserves, transport hydrocarbons through pipelines or other methods to market, decreasing the value of the Group's assets, or reducing the demand for hydrocarbons and refined petroleum products. With increased pressure to reduce GHG emissions by replacing fossil fuel energy generation with alternative energy generation, it is possible that peak demand for gas and oil will be reached, and gas and oil prices will be adversely impacted as and when this happens. Further, 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 adverse investor and stakeholder sentiment towards the hydrocarbon industry and negatively impact the ability to invest in the sector. Similarly, longer term reduction in the demand for hydrocarbon products due to the pace of commercial deployment of alternative energy technologies or due to shifts in consumer preference for lower GHG emissions products could reduce the demand for the hydrocarbons that the Group produces.

Additionally, the SEC's proposed climate change rule was published in March 2022, which, if it goes into effect, would require disclosure of a range of climate related risks. While the proposed climate rule is currently stayed pending various legal challenges in the U.S., the Group is currently assessing this rule, and at this time the Directors cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. To the extent this rule is finalised as proposed, the Group or its customers could incur increased costs related to the assessment and disclosure of climate-related risks. Additionally, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors.

Further, in response to concerns related to climate change, companies in the fossil fuel sector may be exposed to increasing financial risks. Financial institutions, including investment advisors and certain sovereign wealth, pension and endowment funds, may elect in the future to shift some or all of their investment into non-fossil fuel related sectors. Institutional lenders who provide financing to fossil-fuel energy companies have also become more attentive to sustainable lending practices, and some of them may elect in the future not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In 2021, President Biden signed an executive order calling for the development of a "climate finance plan," and, separately, the Federal Reserve announced in 2020 that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. A material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, and transportation activities, which could in turn materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

The Company may also be subject to activism from environmental non-governmental organisations ("**NGOs**") campaigning against fossil fuel extraction or negative publicity from media alleging inadequate remedial actions to retire non-producing wells effectively, which could affect the Group's reputation, disrupt its programs, require the Group to incur significant, unplanned expense to respond or react to intentionally disruptive campaigns or media reports, create blockades to interfere with operations or otherwise materially and adversely impact the Group's business, results of operations, financial condition, cash flows or prospects. Litigation risks are also increasing as a number of entities have sought to bring suit against various oil and natural gas companies in state or federal court, alleging among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts.

Finally, the Group's operations are subject to disruption from the physical effects that may be caused or aggravated by climate change. These include risks from extreme weather events, such as hurricanes, severe storms, floods, heat waves, and ambient temperature increases, as well as wildfires, each of which may become more frequent or more severe as a result of climate change.

The Group relies on third-party infrastructure that it does not control and/or, in each case, is subject to tariff charges that it does not control.

A significant portion of the Group's production passes through third-party owned and controlled infrastructure. If these third-party pipelines or liquids processing facilities experience any event that causes an interruption in operations or a shut-down such as mechanical problems, an explosion, adverse weather conditions, a terrorist attack or labor dispute, the Group's ability to produce or transport natural gas could be severely affected. For example, the Group has an agreement with a third party where approximately 49% of the NGLs sold by the Group during the year ending 31 December 2023 were processed at the third party's facility in Kentucky. Any material decrease in the Group's ability to process or transport its natural gas through third-party infrastructure could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The Group's use of third-party infrastructure may be subject to tariff charges. Although the Group seeks to manage its flow via its midstream infrastructure, the Group may not always be able to avoid higher tariffs or basis blowouts due to the lack of interconnections. In such instances, the tariff charges can be substantial and the cost is not subject to the Group's direct control, although the Group may have certain contractual or governmental protections and rights. Generally, the operator of the gathering or transmission pipelines sets these tariffs and expenses on a cost sharing basis according to the Group's proportionate hydrocarbon through-put of that facility. A provisional tariff rate is applied during the relevant year and then finalised the following year based on the actual final costs and final through-put volumes. Such tariffs are dependent on continued production from assets owned by third parties and, may be priced at such a level as to lead to production from the Group's assets ceasing to be economic and thus may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

Furthermore, the Group's use of third-party infrastructure exposes it to the possibility that such infrastructure will cease to be operational or be decommissioned and therefore require the Group to source alternative export routes and/or prevent economic production from the Group's assets. This could also have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

Failure by the Group, its contractors or its primary offtakers to obtain access to necessary equipment and transportation systems could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

The Group relies on its natural gas and oil field suppliers and contractors to provide materials and services that facilitate the Group's production activities, including plugging and abandonment contractors. Any competitive pressures on the oil field suppliers and contractors could result in a material increase of costs for the materials and services required to conduct the Group's business and operations. For example, the Group is dependent on the availability of plugging vendors to help it satisfy abandonment schedules that the Group has agreed to with the states of Ohio, West Virginia, Kentucky and Pennsylvania. Such personnel and services can be scarce and may not be readily available at the times and places required. Future cost increases could have a material adverse effect on the Group's asset retirement liability, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Group's properties, the Group's planned level of spending for development and the level of the Group's reserves. Prices for the materials and services the Group depends on to conduct its business may not be sustained at levels that enable the Group to operate profitably.

The Group and its offtakers rely, and any future offtakers will rely, upon the availability of pipeline and storage capacity systems, including such infrastructure systems that are owned and operated by third parties. As a result, the Group may be unable to access or source alternatives for the infrastructure and systems which it currently uses or plans to use, or otherwise be subject to interruptions or delays in the availability of infrastructure and systems necessary for the delivery of its natural gas, NGLs and oil to commercial markets. In addition, such infrastructure may be close to its design life and decisions may be taken to decommission such infrastructure or perform life extension work to maintain continued operations. Any of these events could result in disruptions to the Group's projects and thereby impact the Group's ability to deliver natural gas, NGLs and oil to commercial markets and/or may increase the Group's costs associated with the production of natural gas, NGLs and oil reliant upon such infrastructure and systems. Further, the Group's offtakers could become subject to increased tariffs imposed by government regulators or the third-party operators or owners of the transportation systems available for the transport of the Group's natural gas, NGLs and oil, which could result in decreased offtaker demand and downward pricing pressure.

If the Group is unable to access infrastructure systems facilitating the delivery of its natural gas, NGLs and oil to commercial markets due to the Group's contractors or primary offtakers being unable to access the necessary equipment or transportation systems, the Group's operations will be adversely affected. If the Group is unable to source the most efficient and expedient infrastructure systems for its assets then delivery of its natural gas, NGLs and oil to the commercial markets may be negatively impacted, as may its costs associated with the production of natural gas, NGLs and oil reliant upon such infrastructure and systems.

A proportion of the Group's equipment has substantial prior use and significant expenditure may be required to maintain operability and operations integrity.

A part of the Group's business strategy is to optimise or refurbish producing assets where possible to maximise the efficiency of the Group's operations while avoiding significant expenses associated with purchasing new equipment. The Group's producing assets and midstream infrastructure require ongoing maintenance to ensure continued operational integrity. For example, some older wells may struggle to produce suitable line pressure and will require the addition of compression to push natural gas. Despite the Group's planned operating and capital expenditures, there can be no guarantee that the Group's assets or the assets it uses will continue to operate without fault and not suffer material damage in this period through, for example, wear and tear, severe weather conditions, natural disasters or industrial accidents. If the Group's assets, or the assets it uses, do not operate at or above expected efficiencies, the Group's may be required to make substantial expenditures beyond the amounts budgeted. Any material damage to these assets or significant capital expenditure on these assets for improvement or maintenance may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. In addition, as with planned operating and capital expenditure, there is no guarantee that the amounts expended will ensure continued operation without fault or address the effects of wear and tear, severe weather conditions, natural disasters or industrial accidents. The Group cannot guarantee that such optimisation or refurbishment will be commercially feasible to undertake in the future and the Group cannot provide assurance that it will not face unexpected costs during the optimisation or refurbishment process.

The Group depends on its directors, key members of management, independent experts, technical and operational service providers and on the Group's ability to retain and hire such persons to effectively manage its growing business.

The Group's future operating results depend in significant part upon the continued contribution of its directors, key senior management and technical, financial and operations personnel. Management of the Group's growth will require, among other things, stringent control of financial systems and operations, the continued development of the Group's control environment, 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.

In addition, the personal connections and relationships of the Group's directors and key management are important to the conduct of its business. If the Group were to unexpectedly lose a member of its key management or fail to maintain one of the strategic relationships of its key management team, the Group's business, results of operations, financial condition, cash flows or prospects could be materially and adversely affected. In particular, the Group is highly dependent on its Chief Executive Officer, Robert Russell "Rusty" Hutson, Jr. Acquisitions are a key part of the Group's strategy, and Mr. Hutson has been instrumental in sourcing them and securing their financing. Furthermore, as the Group's founder, Mr. Hutson is strongly associated with its success, and if he were to cease being the Chief Executive Officer, perception of the Group's future prospects may be diminished. The Group maintains a "key person" life insurance policy on Mr. Hutson, but not any other of its employees. As a result, the Group is insured against certain losses resulting from the death of Mr. Hutson, but not any of its other employees.

Attracting and retaining additional skilled personnel will be fundamental to the continued growth and operation of the Group's business. The Group requires skilled personnel in the areas of development, operations, engineering, business development, natural gas, NGLs and oil marketing, finance and accounting relating to its projects. Personnel costs, including salaries, are increasing as industry wide demand for suitably qualified personnel increases. The Group may not successfully attract new personnel and retain existing personnel required to continue to expand its business and to successfully execute and implement its business strategy.

The Group may face unanticipated water and other waste disposal costs.

The Group may be subject to regulation that restricts its ability to discharge water produced as part of its natural gas, oil and NGL production operations. Productive zones frequently contain water that must be removed for the natural gas, oil and NGL to produce, and the Group's ability to remove and dispose of sufficient quantities of water from the various zones will determine whether it can produce natural gas, oil and NGL in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from the Group's wells may affect its ability to produce its wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce the Group's profitability. The Group has entered into various water management services agreements in the Appalachian Basin which provide for the disposal of its produced water by established counterparties with large integrated pipeline networks. If these counterparties fail to perform, the Group may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase for a number of reasons, including if new laws and regulations require water to be disposed in a different manner.

In 2016, the EPA adopted effluent limitations for the treatment and discharge of wastewater resulting from onshore unconventional natural gas, oil and NGL extraction facilities to publicly owned treatment works. In addition, the injection of fluids gathered from natural gas, oil and NGL producing operations in underground disposal wells has been identified by some groups and regulators as a potential cause of increased seismic events in certain areas of the country, including the states of West Virginia, Ohio and Kentucky in the Appalachian Basin as well as Oklahoma, Texas and Louisiana in the Group's Central Region. Certain states, including those located in the Appalachian Basin have adopted, or are considering adopting, laws and regulations that may restrict or prohibit oilfield fluid disposal in certain areas or underground disposal wells, and state agencies implementing those requirements may issue orders directing certain wells in areas where seismic events have occurred to restrict or suspend disposal well permits or operations or impose certain conditions related to disposal well construction, monitoring, or operations. Any of these developments could increase the Group's cost to dispose of its produced water.

The Group may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to the authority under the Natural Gas Pipeline Safety Act of 1968 ("**NGPSA**") and Hazardous Liquid Pipeline Safety Act of 1979 ("**HLPSA**"), as amended by the Pipeline Safety Improvement Act of 2002 ("**PSIA**"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("**PIPESA**") and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "**2011 Pipeline Safety Act**"), the Pipeline and Hazardous Materials Safety Administration ("**PHMSA**") has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect high consequence areas ("**HCAs**"), which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterise applicable threats to pipeline segments that could impact HCAs;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and

- implement preventive and mitigating actions.

In addition, states in the US have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines. At this time, the Group cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of pipeline integrity testing, but the results of these tests could cause the Group to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the safe and reliable operation of the Group's pipelines.

The 2011 Pipeline Safety Act amends the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. Additionally, pursuant to one of the requirements of the 2011 Pipeline Safety Act, in May 2016, PHMSA proposed rules that would, if adopted, impose more stringent requirements for certain gas lines, extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond HCAs to cover gas pipelines found in newly defined "moderate consequence areas" that contain as few as five dwellings within the potential impact area and require gas pipelines installed before 1970 that were exempted from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("**MAOP**"). Other requirements proposed by PHMSA under the rulemaking include: reporting to PHMSA in the event of certain MAOP exceedances; strengthening PHMSA integrity management requirements; considering seismicity in evaluating threats to a pipeline; conducting hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and using more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on gathering lines. In January 2017, PHMSA finalised new regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, repairs and leak detection), regardless of the pipeline's proximity to an HCA. The final rule also requires all pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes, or other similar events that are likely to damage infrastructure. PHMSA regularly revises its pipeline safety regulations. For example, in June 2016, the President signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "**2016 PIPES Act**") into law. The 2016 PIPES Act reauthorises PHMSA through 2019, and facilitates greater pipeline safety by providing PHMSA with emergency order authority, including authority to issue prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities to address imminent hazards, without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements, requiring a review of both natural gas and hazardous liquid integrity management programs, and mandating the creation of a working group to consider the development of an information-sharing system related to integrity risk analyses. The 2016 PIPES Act also requires that PHMSA publish periodic updates on the status of those mandates outstanding from the 2011 Pipeline Safety Act. PHMSA has recently published three parts of its so-called "Mega Rule", including rules focused on: the safety of gas transmission pipelines, the safety of hazardous liquid pipelines and enhanced emergency order procedures. PHMSA finalised the first part of the rule, which primarily addressed maximum operating pressure and integrity management near HCAs for onshore gas transmission pipelines, in October 2019. PHMSA finalised the second part of the rule, which extended federal safety requirements to onshore gas gathering pipelines with large diameters and high operating pressures, in November 2021. PHMSA published the final of the three components of the Mega Rule in August 2022, which took effect in May 2023. The final rule applies to onshore gas transmission pipelines, and clarifies integrity management regulations, expands corrosion control requirements, mandates inspection after extreme weather events, and updates existing repair criteria for both HCA and non-HCA pipelines. Finally, PHMSA published a Notice of Proposed Rulemaking regarding more stringent gas pipeline leak detection and repair requirements to reduce natural gas emissions on 18 May 2023.

At this time, the Group cannot predict the cost of such requirements, but they could be significant. Moreover, federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject the Group to increased capital costs, operational delays and costs of operation.

Moreover, as of January 2023, the maximum civil penalties PHMSA can impose are $257,664 per pipeline safety violation per day, with a maximum of $2,576,627 for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require the Group to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in the Group incurring increased operating costs that could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. States are also pursuing regulatory programs intended to safely build pipeline infrastructure. The adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on the Group and similarly situated midstream operators.

The Group is currently operating in a period of economic uncertainty and capital markets disruption, which has been significantly impacted by geopolitical instability due to the ongoing military conflict between Russia and Ukraine and more recently, the Israel-Hamas war. The Group's business may be adversely affected by any negative impact on the global economy and capital markets resulting from the conflict in Ukraine or any other geopolitical tensions.

U.S. and global markets are experiencing volatility and disruption following the escalation of geopolitical tensions and the start of the military conflict between Russia and Ukraine. In February 2022, a full-scale military invasion of Ukraine by Russian troops transpired. Although the length and impact of the ongoing military conflict is highly unpredictable, the conflict in Ukraine has led, and could continue to lead, to market disruptions, including significant volatility in commodity prices, credit and capital markets, as well as supply chain interruptions.

Additionally, Russia's prior annexation of Crimea, recent recognition of two separatist republics in the Donetsk and Luhansk regions of Ukraine and subsequent military interventions in Ukraine have led to sanctions and other penalties being levied by the United States, European Union and other countries against Russia, Belarus, the Crimea Region of Ukraine, the so-called Donetsk People's Republic, and the so-called Luhansk People's Republic, including agreement to remove certain Russian financial institutions from the Society for Worldwide Interbank Financial Telecommunication ("**SWIFT**") payment system, expansive bans on imports and exports of products to and from Russia and bans on the exportation of U.S. denominated banknotes to Russia or persons located there. Additional potential sanctions and penalties have also been proposed and/or threatened. Russian military actions and the resulting sanctions could adversely affect the global economy and financial markets and lead to instability and lack of liquidity in capital markets, potentially making it more difficult for the Group to obtain additional funds.

Additionally, on 7 October 2023, Hamas, a U.S. designated terrorist organisation, launched a series of coordinated attacks from the Gaza Strip onto Israel. On 8 October 2023, Israel formally declared war on Hamas, and the armed conflict is ongoing as of the date of this document. Hostilities between Israel and Hamas could escalate and involve surrounding countries in the Middle East. The Group is actively monitoring the situation in Ukraine and Israel and assessing its impact on the Group's business. To date the Group has not experienced any material interruptions in its infrastructure, supplies, technology systems or networks needed to support its operations given its operating areas are exclusively located within the Central Region and the Appalachian Basins of the U.S. The Group has no way to predict the progress or outcome of the conflict in Ukraine or Israel or their impacts in Ukraine, Russia, Belarus, Israel or the Gaza Strip as the conflicts, and any resulting government reactions, are rapidly developing and beyond the Group's control. The extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have substantial impact on the global economy and the Group's business for an unknown period of time. Any of the aforementioned factors could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects. Any such disruptions may also magnify the impact of other risks described in this prospectus.

RISKS RELATING TO THE GROUP'S FINANCING, ACQUISITIONS, INVESTMENT AND INDEBTEDNESS

Inflation may adversely affect the Group by increasing costs beyond what it can recover through price increases and limit the Group's ability to enter into future debt financing.

Inflation can adversely affect the Group by increasing costs of materials, equipment, labor and other services. In addition, inflation is often accompanied by higher interest rates. Continued inflationary pressures could impact the Group's profitability. Though the Directors believe that the rates of inflation in recent years, including the twelve-month period ended 31 December 2023, have not had a significant impact on the Group's operations, a continued increase in inflation, including inflationary pressure on labor, could result in increases to the Group's operating costs, and the Group may be unable to pass these costs on to its customers. These inflationary pressures could also adversely impact the Group's ability to procure materials and equipment in a cost-effective manner, which could result in reduced margins and production delays and, as a result, the Group's business, financial condition, results of operations and cash flows could be materially and adversely affected. The Group continues to undertake actions and implement plans to address these inflationary pressures and protect the requisite access to materials and equipment. With respect to the Group's costs of capital, the ABS Notes are fixed-rate instruments (subject to adjustment pursuant to the sustainability-linked features) and as of 30 June 2024, the Group had approximately $268 million outstanding on its Credit Facility. Nevertheless, inflation may also affect the Group's ability to enter into future debt financing, including refinancing of the Credit Facility or issuing additional SPV-level asset backed securities, as high inflation may result in a relative increase in the cost of debt capital.

The Group is taking efforts to mitigate inflationary pressures, by working closely with other suppliers and service providers to ensure procurement of materials and equipment in a cost-effective manner. However, these mitigation efforts may not succeed or may be insufficient.

Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish further, which could impact the price at which natural gas, NGLs and oil can be sold, which could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

There are risks inherent in the Group's acquisitions of natural gas and oil assets.

Acquisitions are an essential part of the Group's strategy for protecting and growing cash flow, particularly in relation to the risk that some of the Group's wells may have a higher than anticipated production decline rate. Over the past several years, the Group's has undertaken a number of acquisitions of natural gas and oil assets (and of companies holding such assets), including, but not limited to the acquisition of certain assets of Oaktree Capital Management, L.P., the acquisition of certain assets of Crescent Pass, the acquisition of certain assets of Carbon Energy Corporation, the acquisition of certain assets and infrastructure of EQT Corporation, the acquisition of certain assets from Triad Hunter, LLC, the acquisition of 51.25% working interest in certain assets and infrastructure from Indigo Minerals LLC, the acquisition of certain assets and infrastructure from Blackbeard Operating LLC, the acquisition of 51.25% working interest in certain assets, infrastructure, equipment and facilities in conjunction with Oaktree from Tanos Energy Holdings III, LLC, the acquisition of 51.25% working interest in certain assets, infrastructure, equipment and facilities in conjunction with Oaktree from Tapstone Energy Holdings LLC and the acquisition of 52.5% working interest in certain upstream assets and related facilities within the Central Region from a private seller, in conjunction with Oaktree, the acquisition of certain upstream assets and related infrastructure within the Central Region from Tanos Energy Holdings II LLC and the acquisition of certain upstream assets and related gathering infrastructure in the Central Region from ConocoPhillips. The Group's ability to complete future acquisitions will depend on it being able to identify suitable acquisition candidates and negotiate favorable terms for their acquisition, in each case, before any attractive candidates are purchased by other parties such as private equity firms, some of whom have substantially greater financial and other resources than the Group. The Group may face competition for attractive acquisition targets that may also increase the price of the target business. As a result, there is no assurance that the Group will always be able to source and execute acquisitions in the future at attractive valuations.

Furthermore, to further the Company's growth, the Group has made further acquisitions outside the Appalachian Basin, a region in which the Group has developed its operational experience into the Bossier Shale, the Haynesville Shale, the Barnett Shale Play, and the Cotton Valley and Mid-Continent producing areas. Accordingly, an acquisition in a new area in which the Group lacks experience may present unanticipated risks and challenges that were not accounted for or previously experienced. Ordinarily, the Group's due diligence efforts are focused on higher valued and material properties or assets. Even an in-depth review of all properties and records may not reveal all existing or potential problems, nor will such review always permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Generally, physical inspections are not performed on every well or facility, and structural or environmental problems are not necessarily observable even when an inspection is undertaken.

There can be no assurance that the Group's prior acquisitions or any other potential acquisition will perform operationally as anticipated or be profitable. The Group could fail to appropriately value any acquired business and the value of any business, company or property that it acquires or invests in may actually be less than the amount paid for it or its estimated production capacity. The Group may be required to assume pre-closing liabilities with respect to an acquisition, including known and unknown title, contractual, and environmental and decommissioning liabilities, and may acquire interests in properties on an "as is" basis without recourse to the seller of such interest or the seller may have limited resources to provide post-sale indemnities.

In addition, successful acquisitions of gas and oil assets require an assessment of a number of factors, including estimates of recoverable reserves, the time of recovering reserves, exploration potential, future natural gas, NGLs and oil prices and operating costs. Such assessments are inexact, and the Group cannot guarantee that it makes these assessments with a high degree of accuracy. In connection with assessments, the Group performs a review of the acquired assets. However, such a review will not reveal all existing or potential problems. Furthermore, review may not permit the Group to become sufficiently familiar with the assets to fully assess their deficiencies and capabilities.

Integrating operations, technology, systems, management, back office personnel and pre- or post- completion costs for future acquisitions may prove more difficult or expensive than anticipated, thereby rendering the value of any company or assets acquired less than the amount paid. The Group may also take on unexpected liabilities which are uncapped, have to undertake unanticipated capital expenditures in connection with a new acquisition or provide uncapped liabilities in connection with the purchase and sale of assets, which are customary in such agreements. The integration of acquired businesses or assets requires significant time and effort on the part of the Group's management. Following such integration efforts, prior acquisitions may still not achieve the level of financial or operational performance that was anticipated when they were acquired. In addition, the integration of new acquisitions can be difficult and disrupt the Group's own business because the Group's operational and business culture may differ from the cultures of the acquired businesses, unpopular cost-cutting measures may be required, internal controls may be more difficult to maintain and control over cash flows and expenditures may be difficult to establish. If the Group encounters any of the foregoing issues in relation to one of its acquisitions, this could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The Group may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt its business and hinder its ability to grow.

In the future the Group may make acquisitions of businesses that complement or expand its current business. However, the Group may not be able to identify attractive acquisition opportunities. Even if the Group does identify attractive acquisition opportunities, it may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on the Group's ability to integrate effectively the acquired business into its existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of the Group's managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that the Group will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. The Group's failure to achieve consolidation savings, to integrate the acquired businesses and assets into the Group's existing operations successfully or to minimise any unforeseen operational difficulties could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The Group's Credit Facility also limits its ability to incur certain indebtedness, which could indirectly limit the Group's ability to engage in acquisitions of businesses.

The Group may not have good title to all its assets and licenses.

Although the Directors believes that the Group takes due care and conducts due diligence on new acquisitions in a manner that is consistent with industry practice, there can be no assurance that the Group has good title to all its assets and the rights to develop and produce natural gas and oil from its assets. Such reviews are inherently incomplete and it is generally not feasible to review in depth every individual well or field involved in each acquisition. There can be no assurance that any due diligence carried out by the Group or by third parties on its behalf in connection with any assets that it acquires will reveal all of the risks associated with those assets, and the assets may be subject to preferential purchase rights, consents and title defects that were not apparent at the time of acquisition. The Group may acquire interests in properties on an "as is" basis without recourse to the seller of such interest or the seller may have limited resources to provide post-sale indemnities. In addition, changes in law or change in the interpretation of law or political events may arise to defeat or impair the Group's claim to certain properties which it currently owns or may acquire which could result in a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The issuance of additional Ordinary Shares in connection with acquisitions by the Group or other growth opportunities, any share incentive or share option plan or otherwise may dilute all other shareholdings.

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

As of the Latest Practicable Date, the Company has issued options under its equity incentive plans to employees and the executive director and options over a total of 153,631 ordinary shares are currently outstanding, and has also entered into restricted stock unit agreements and performance stock unit agreements with certain employees, of which 1,183,973 restricted stock units and 1,218,987 performance stock units are outstanding. The Company may, in the future, issue further options and/or warrants to subscribe for new Ordinary Shares to certain advisers, employees, directors, senior management and/or consultants of the Company. The exercise of any such options would result in a dilution of the shareholdings of other investors.

Additionally, although the Company currently has no other plans for an offering of Ordinary Shares, it is possible that it may decide to offer additional Ordinary Shares in the future. Subject to any applicable pre-emption rights, any future issues of Ordinary Shares by the Company may have a dilutive effect on the holdings of Shareholders and could have a material adverse effect on the market price of Ordinary Shares as a whole.

Restrictions in the Group's existing and future debt agreements could limit its growth and its ability to engage in certain activities.

The Group's Credit Facility contains a number of significant covenants that may limit its ability to, among other things:

- incur additional indebtedness;
- incur liens;
- sell assets;
- make certain debt payments;
- enter into agreements that restrict or prohibit the payment of dividends;
- limits the subsidiaries' ability to make certain payments with respect to their equity, based on the pro forma effect thereof on certain financial ratios, which would be the source of distributable profits from which the Company may issue a dividend; and
- conduct hedging activities.

In addition, the Credit Facility requires the Group to maintain compliance with certain financial covenants. The Group may also be prevented from taking advantage of business opportunities that arise because of the limitations from the restrictive covenants under the Credit Facility. These restrictions may limit the Group's ability to obtain future financings to withstand a future downturn in the Group's business or the economy in general, or to otherwise conduct necessary corporate activities.

A breach of any covenant in the Credit Facility will result in a default under the agreement and may result in an event of default under the Credit Facility if such default is not cured during any applicable grace period. An event of default, if not waived, could result in acceleration of the indebtedness outstanding under the Credit Facility and in an event of default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements to which the Group is a party. Any such accelerated indebtedness would become immediately due and payable. If that occurs, the Group may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to the Group.

Any significant reduction in the borrowing base under the Credit Facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact the Group's ability to fund its operations.

The Credit Facility limits the amounts the Group can borrow up to a borrowing base amount, which the lenders, in their sole discretion, unilaterally determine based upon the Group's reserve reports for the applicable period and other data and reports. Such determinations will be made on a regular basis semi-annually (each a "**Scheduled Redetermination**") and at the option of the lenders with more than 66.6% of the loans and commitments under the Credit Facility, no more than one time in between each Scheduled Redetermination. As of the Latest Practicable Date, the Group's borrowing base is $385 million.

In the future, the Group may not be able to access adequate funding under its Credit Facility as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a borrowing base redetermination, or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover a defaulting lender's portion. Declines in commodity prices from their current levels could result in a determination to lower the borrowing base and, in such a case, the Group could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, the Group may be unable to make acquisitions or otherwise carry out business plans, which could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The securitisations of the Group's limited purpose, bankruptcy-remote, wholly owned subsidiaries may expose the Group to financing and other risks, and there can be no assurance that the Group will be able to access the securitisation market in the future, which may require it to seek more costly financing.

Through limited purpose, bankruptcy-remote, wholly owned subsidiaries ("**SPVs**"), the Group has securitised and expects to securitise in the future, certain of its assets to generate financing. In such transactions, the Group conveys a pool of assets to an SPV, that, in turn, issues certain securities or enters into certain debt agreements. The securities issued by the SPVs are each collateralised by a pool of assets. In exchange for the transfer of finance receivables to the SPV, the Group typically receives the cash proceeds from the sale of the securities or entering into term loans.

Although the Group's SPVs have successfully completed securitisations through the ABS I, II, III, IV, V, VI and VIII Notes, there can be no assurance that the Group, through its SPVs, will be able to complete additional securitisations, particularly if the securitisation markets become constrained. In addition, the value of any securities that the Group's limited purpose, bankruptcy-remote, wholly owned subsidiaries retain in its securitisations, including securities retained to comply with applicable risk retention rules, might be reduced or, in some cases, eliminated as a result of an adverse change in economic conditions or the financial markets. In addition, the Group's ABS I, II, IV, VI and VIII are subject to customary accelerated amortisation events, including events tied to the failure to maintain stated debt service coverage ratios.

If it is not possible or economical for the Group to securitise its assets in the future, the Group would need to seek alternative financing to support its operations and to meet its existing debt obligations, which may be less efficient and more expensive than raising capital via securitisations and may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

An increase in interest rates would increase the cost of servicing the Group's indebtedness and could reduce its profitability, decrease its liquidity and impact its solvency.

The Credit Facility provides for, and the Group's future debt agreements may provide for, debt incurred thereunder to bear interest at variable rates. As of 30 June 2024, the Group had $268 million outstanding on its Credit Facility. Increases in interest rates would increase the cost of servicing indebtedness under its Credit Facility or under future debt agreements subject to interest at variable rates, and materially reduce the Group's profitability, which may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. As of the Latest Practicable Date, the Group had $312 million outstanding on its Credit Facility.

The Group's hedging activities could result in financial losses or could reduce its net income.

To achieve more predictable cash flows, the Group employs a hedging strategy involving opportunistically hedging a majority of its first two years of production as well as hedging a significant percentage of production beyond its first two years of forecasted production. Even so, the remainder of its production that is unhedged is exposed to the continuing and prolonged declines in the prices of natural gas, NGLs and oil. The Group's results of operations and financial condition would be negatively impacted if the prices of natural gas, NGLs or oil were to remain depressed or decline materially from current levels. To achieve more predictable cash flows and to reduce the Group's exposure to fluctuations in the prices of natural gas, NGLS and oil, the Group may enter into additional hedging arrangements for a significant portion of its production.

The Group's derivative contracts may result in substantial gains or losses. For example, the Group reported an operating profit of $1,161 million for the year ended 31 December 2023, compared with an operating loss of $671 million for the year ended 31 December 2022. While the Group's earnings are impacted by a variety of factors, a key driver of the year over year change from an operating loss to profit was attributable to a change of $1,767 million in the mark-to-market valuation adjustment on the Group's derivative financial instrument valuations to $906 million gain in 2023 from an $861 million loss in 2022. There can be no assurance that the Group will not realise additional losses due to its hedging activities in the future. In addition, if the Group enters into any derivative contracts and experiences a sustained material interruption in its production, it might be forced to satisfy all or a portion of its hedging obligations without the benefit of the cash flows from its sale of the underlying physical commodity, resulting in a substantial diminution of its liquidity.

The Group's ability to use hedging transactions to protect it from future natural gas, NGL and oil price volatility will be dependent upon natural gas, NGL and oil 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 sensitive to commodity price changes. In addition, if commodity prices remain low, the Group will not be able to replace its hedges or enter into new hedges at favorable prices.

The Group's price hedging strategy and future hedging transactions will be determined at its discretion, subject to the terms of certain agreements governing its indebtedness. The prices at which the Group hedges its production in the future will be dependent upon commodity prices at the time it enters into these transactions, which may be substantially higher or lower than current prices. Accordingly, the Group's price hedging strategy may not protect it from significant declines in prices received for its future production. Conversely, the Group's hedging strategy may limit its ability to realise cash flows from commodity price increases. It is also possible that a substantially larger percentage of the Group's future production will not be hedged as compared with the next few years, which would result in the Group's natural gas, NGL and oil revenues becoming more sensitive to commodity price fluctuations.

The failure of the Group's hedge counterparties to meet their obligations to the Group may adversely affect the Group's financial results.

An attendant risk exists in hedging activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that the Group will not realise the benefit of the hedge. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and the Group may not be able to realise the benefit of the derivative contract. Any default by the counterparty to these derivative contracts when they become due would have a material adverse effect on the Group's business, results of operations, financial condition, cash flows and prospects.

The Group may not be able to enter into commodity derivatives on favourable terms or at all.

To achieve a more predictable cash flow, the Group employs a hedging strategy involving opportunistically hedging a majority of its first two years of production as well as hedging a significant percentage of production beyond its first two years of forecasted production. If the Group is unable to maintain sufficient hedging capacity with its counterparties, the Group could have greater exposure to changes in commodity prices and interest rates, which could have a material adverse impact on the Group's business, results of operations, financial condition, cash flows or prospects.

RISKS RELATING TO LEGAL, TAX, ENVIRONMENTAL AND REGULATORY MATTERS

The Group is subject to regulation and liability under environmental, health and safety regulations, the violation of which may materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

The Group operates in an industry that has certain inherent hazards and risks, and consequently the Group is subject to stringent and comprehensive laws and regulations, especially with regard to the protection of health, safety and the environment. For example, the Group is subject to laws and regulations related to occupational safety and health, hydraulic fracturing activities, air emissions, soil and water quality, the protection of threatened and endangered plant and animal species, biodiversity and ecosystems, and the safety of its assets and employees. Although the Group believes that it has adequate procedures in place to mitigate operational risks, there can be no assurances that these procedures will be adequate to address every potential health, safety and environmental hazard, and a failure to adequately mitigate risks may result in loss of life, injury, or adverse impacts on the health of employees, contractors and third-parties or the environment. Any failure by the Group or one of its subcontractors, whether inadvertent or otherwise, to comply with applicable legal or regulatory requirements may give rise to civil, administrative and/or criminal liabilities, civil fines and penalties, delays or restrictions in acquiring or disposing of assets and/or delays in securing or maintaining required permits, licenses and approvals. Further, a lack of regulatory compliance may lead to denial, suspension, or termination of permits, licenses, or approvals that are required to operate the Group's sites or could result in other operational restrictions or obligations. The Group's health, safety and environmental policies require the Group to observe local, state and national legal and regulatory requirements and to apply generally accepted industry best practices where legislation or regulation does not exist.

The terms and conditions of licenses, permits, regulatory orders, approvals, or permissions may include more stringent operational, environmental and/or health and safety requirements. Obtaining development or production licenses and permits may become more difficult or may be delayed due to federal, regional, state or local governmental constraints, considerations, or requirements on issuing. Furthermore, third- parties such as environmental NGOs may administratively or judicially contest or protest licenses and permits already granted by relevant authorities or applications for the same and operations may be subject to other administrative or judicial challenges.

In addition, under certain environmental laws and regulations, the Group could be subject to joint and several strict liability for the removal or remediation of previously released materials, pollution, or property contamination regardless of whether the Group was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties on or adjacent to well sites and facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases of pollutants or contaminants could expose the Group to significant liabilities that could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The Group incurs, and expects to continue to incur, capital and operating costs in an effort to comply with increasingly complex operational health and safety and environmental laws and regulations. New laws and regulations, the imposition of more stringent requirements in permits and licenses, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and permits and licenses, or the discovery of previously unknown contamination or hazards may require further costly expenditures to, for example:

- modify operations, including an increase in plugging and abandonment operations;
- install or upgrade pollution or emissions control equipment;
- perform site clean ups, including the remediation and reclamation of gas and oil sites;
- curtail or cease certain operations;
- provide financial securities, bonds, and/or take out insurance; or
- pay fees or fines or make other payments for pollution, discharges to the environment or other breaches of environmental or health and safety requirements or consent agreements with regulatory agencies.

The Directors cannot predict with any certainty the full impact of any new laws, regulations, or policies on the Group's operations or on the cost or availability of insurance to cover the risks associated with such operations. The costs of such measures and liabilities related to potential operational, health, safety or environmental risks associated with the Group may increase, which could materially and adversely affect its business, results of operations, financial condition, cash flows or prospects. In addition, it is not possible to predict what future operational health and safety or environmental laws and regulations will be enacted or how current or future operational, health, safety or environmental laws and regulations will be applied or enforced. The Group may have to incur significant expenditure for the installation and operation of additional systems and equipment for monitoring and carry out remedial measures in the event that operational health and safety and environmental laws and regulations become more stringent or costly reform is implemented by regulators. Any such expenditure may have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. No assurance can be given that compliance with occupational health and safety and environmental laws or regulations in the regions where the Group operates will not result in a curtailment of production or a material increase in the cost of production or development activities.

Increasing attention to sustainability matters may impact the Group's business and financial results.

Increasing attention has been given to corporate activities related to sustainability matters in public discourse and the investment community. A number of advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to sustainability matters, including through the investment and voting practices of investment advisers, public pension funds, activist investors, universities and other members of the investing community. These activities include increasing attention and demands for action related to climate change, advocating for changes to companies' board of directors and promoting the use of alternative forms of energy. These activities may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against the Group. In addition, a failure to comply with evolving investor or customer expectations and standards or if the Group is perceived to not have responded appropriately to the growing concern for sustainability 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 operation.

In addition, 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. Unfavorable 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 have a negative impact on the price of Ordinary Shares and the Group's access to and costs of capital. Also, institutional lenders may decide not to provide funding for oil and natural gas companies based on climate change related concerns, which could affect the Group's access to capital for potential growth projects.

The current U.S. administration, acting through the executive branch and/or in coordination with Congress, could enact laws, and rules and regulations may be passed at the federal, state and/or local level in jurisdictions in which the Group operates that could impose more onerous permitting and other costly environmental, health and safety requirements on the Group's operations.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change-related commitments expressed by some political candidates who are now, or may in the future be, in political office.

While the Group's operations are largely not conducted on federal lands, it may in the future consider acquisitions of natural gas and oil assets located in areas in which the development of such assets would require permits and authorisations to be obtained from or issued by federal and/or state agencies. To conduct these operations, the Group may be required to file applications for permits, seek agency authorisations and comply with various other statutory and regulatory requirements. Further, new oil and gas leasing on public lands has been subject of recent proposed reforms, including bans in certain areas, raising royalty rates and implementing stricter standards for entities seeking to purchase oil and gas leases. While the federal government under President Trump has indicated an interest in, and taken certain initial actions in the first days of the administration relating to, diverging from the climate change and GHG reductions of the prior administration, states and local governments may act in the absence of federal action relating to permitting and/or otherwise imposing restrictions on Group operations. Complying with any of these requirements may adversely affect the Group's ability to conduct operations at the costs and in the time periods anticipated, and may consequently adversely impact the Group's anticipated returns from its operations and could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

The Group's operations are dependent on its compliance with obligations under permits, licenses, contracts and field development plans.

The Group's operations must be carried out in accordance with the terms of permits, licenses, operating agreements, annual work programs and budgets. Fines, penalties, or enforcement actions may be imposed and a permit or license may be suspended or terminated if a permit or license holder, or party to a related agreement, fails to comply with its obligations under such permit, license or agreement, or fails to make timely payments of levies and taxes for the licensed activity, or fails to 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 permits or licenses as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which the Group does business, or in which it may do business in the future, may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

In addition, the Group and its commercial partners, as applicable, have obligations to operate assets in accordance with specific requirements under certain licenses and related agreements, field development agreements, laws and regulations. If the Group or its partners were to fail to satisfy such obligations with respect to a specific field, the license or related agreements for that field may be suspended, revoked or terminated. Although the Group has in the past acquired and may in the future acquire shale assets, a significant source of its natural gas and crude oil remains conventional wells. In some instances, these conventional wells are located on the same property as unconventional wells that produce shale oil. In these cases, the rights to access the shale layers of the property will typically be conditioned on the ongoing productivity of conventional wells on the property. Furthermore, the shale rights may be owned by a third party, and in such instances, the Group will enter into a joint use agreement with the third party. This joint use agreement may stipulate that in consideration for permission to operate the conventional wells, the Group is to use reasonable efforts to maintain production so that the third party retains the shale licenses. If the Group fails to maintain production in the conventional wells, under the joint use agreement, the Group may be liable to the third party for replacing the lost land rights. The relevant authorities are typically authorised to, and do from time to time, inspect to verify compliance by the Group or its commercial partners, as applicable, with relevant laws and the licenses or the agreements pursuant to which the Group conducts its business. There can be no assurance that the views of the relevant government agencies regarding the development of the fields that the Group's operates or the compliance with the terms of the licenses pursuant to which the Group conducts such operations will coincide with its views, which might lead to disagreements that may not be resolved.

The suspension, revocation, withdrawal or termination of any of the permits, licenses or related agreements pursuant to which the Group may conduct business, as well as any delays in the continuous development of or production at its fields caused by the issues detailed above could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects. In addition, failure to comply with the obligations under the permits, licenses or agreements pursuant to which the Group conducts business, whether inadvertent or otherwise, may lead to fines, penalties, restrictions, enforcement actions brought by governmental authorities, withdrawal of licenses and termination of related agreements.

The Group does not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions.

The Group insures its operations in accordance with industry practice and plans to continue to insure the risks it considers appropriate for its needs and circumstances. However, the Group may elect not to 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 remote.

The Group's insurance may not be adequate to 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, blow-outs 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 or joint venture partners may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources.

Operational insurance policies are usually placed in one year contracts and the insurance market can withdraw cover for certain risks due to events occurring in other parts of the industry, thus greatly increasing the costs of risk transfer. For example, in September 2018, a gas pipeline operated by another midstream company exploded in Beaver County, Pennsylvania, a state in which the Group has operations. The explosion resulted in the destruction of residential property and motor vehicles as well as the evacuation of nearby households. Catastrophic events such as these may cause the insurance costs for the Group's midstream operations to rise, despite it not being involved in the catastrophic event. In the event that insurance coverage is not available or the Group's insurance is insufficient to fully cover any losses, including losses incurred due to lost revenues resulting from third party operations or processing plants, claims and/or liabilities incurred, or indemnities are difficult to enforce, the Group's business and operations, financial results or financial position may be disrupted and adversely affected.

The payment by the Group's insurers of any insurance claims may result in increases in the premiums payable by the Group's 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.

The Group's internal systems and website may be subject to intentional and unintentional disruption, and its confidential information may be misappropriated, stolen or misused, which could adversely impact the Group's reputation and future sales.

The Group has faced, and may in the future continue to face, cyber-attacks and data security breaches. Such cyber-attacks and breaches are designed to penetrate the Group's network security or the security of its internal systems, misappropriate proprietary information and/or cause interruptions to its services, and the Group expects to continue to face similar threats in the future. The Group cannot guarantee that it will be able to successfully prevent all attacks in the future. Such future attacks could include hackers obtaining access to its systems, the introduction of malicious computer code or denial of service attacks. If an actual or perceived breach of the Group's network security occurs, it could adversely affect the Group's business or reputation, and may expose the Group to the loss of information, litigation and possible liability. An actual security breach could also impair the Group's ability to operate its business and provide products and services to its customers. Additionally, malicious attacks, including cyber-attacks, may damage the Group's assets, prevent production at its producing assets and otherwise significantly affect corporate activities. For example, the Group utilises electronic monitoring of meters and flow rate devices to monitor pressure build-up in its production wells. If there were a cyber-attack that penetrated its monitoring systems such that they provided false readings, this could result in an unknown pressure build-up, creating a dangerous situation which could end up in an explosion. As techniques used to obtain unauthorised access to or to sabotage systems change frequently and may not be known until launched against the Group or its third-party service providers, the Group may be unable to anticipate or implement adequate measures to protect against these attacks and the Group's service providers may likewise be unable to do so. Such an outcome would have a material adverse impact on the Group's business, results of operations, financial condition, cash flows or prospects.

In addition, confidential or financial payment information that the Group maintains may be subject to misappropriation, theft and deliberate or unintentional misuse by current or former employees, third-party contractors or other parties who have had access to such information. Any such misappropriation and/or misuse of the Group's information could result in the Group, among other things, being in breach of certain data protection requirements and related legislation as well as incurring liability to third parties. The Directors expect that the Group will need to continue closely monitoring the accessibility and use of confidential information in its business, educate its employees and third-party contractors about the risks and consequences of any misuse of confidential information and, to the extent necessary, pursue legal or other remedies to enforce its policies and deter future misuse. If the Group's confidential information is misappropriated, stolen or misused as a result of a disruption to its website or internal systems this could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

Although the Group maintains insurance to protect against losses resulting from certain of data protection breaches and cyber-attacks, the Group's coverage for protecting against such risks may not be sufficient.

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

From time to time, the Group may be subject, directly or indirectly, to litigation arising out of its operations and the regulatory environments in its areas of operations. Historically, categories of litigation that the Group has faced included actions by royalty owners over payment disputes, personal injury claims and property related claims, including claims over property damage, trespass or nuisance. Although the Group currently faces no material litigation for which it is not sufficiently indemnified or insured, damages claimed under such litigation in the future may be material or may be indeterminate, and the outcome of such litigation, if determined adversely to the Group, could individually or in the aggregate, be reasonably expected to have a material and adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects. 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 or prospects.

The Group is subject to certain tax risks.

Any change in the Group's tax status or in taxation legislation in the United Kingdom or the United States could affect its ability to provide returns to shareholders. Statements in this document concerning the taxation of holders of the Ordinary Shares are based on current law and practice, which is subject to change.

The Group is subject to income taxes in the United Kingdom and the United States, and there can be no certainty that the current taxation regime in the United Kingdom, the United States or other jurisdictions within which it currently operates or may operate in the future will remain in force or that the current levels of corporation taxation will remain unchanged. For example, the U.S. government has imposed a minimum tax on corporations and proposed and may enact significant changes to the taxation of business entities including, among others, an increase in the U.S. federal income tax rate applicable to corporations, like the Company and surtaxes on certain types of income. Certain U.S. localities also maintain a severance tax or impact fee on the removal of oil and natural gas from the ground and such tax rates may be increased or new severance taxes or impact fees may be implemented. The United Kingdom announced on May 26 2022 a new "Energy Profits Levy" on oil and gas exploration and production companies operating in the United Kingdom and the UK Continental Shelf at a rate of 25% (subsequently increased to 35% and then to 38% from 1 November 2024).

As the Group does not operate its exploration, production or extraction activities in the United Kingdom or in the UK Continental Shelf, it does not expect the Energy Profits Levy to impact its headline corporation tax rate in the United Kingdom, however, the taxation of energy companies remains uncertain, particularly in the context of current global events, and the future stability of such tax regimes cannot be guaranteed.

The Group's domestic and international tax liabilities are subject to the allocation of expenses in differing jurisdictions. The Group's effective tax rate could be adversely affected by changes in the mix of earnings and losses in taxing jurisdictions with differing statutory tax rates, certain non-deductible expenses, the valuation of deferred tax assets and liabilities and changes in federal, state or international tax laws and accounting principles. Increases in the Group's effective tax rate could materially affect its net financial results. Although the Group believes that its income tax liabilities are reasonably estimated and accounted for in accordance with applicable laws and principles, an adverse resolution of one or more uncertain tax positions in any period could have a material adverse effect on the Group's business, results of operations, financial condition, cash flows or prospects.

In the past the Group has been able to offset a large portion of its U.S. federal income tax burden with marginal well tax credits that are available to qualified producers who operate lower-volume wells during a low commodity pricing environment. There can be no assurance that there will be no amendment to the existing taxation laws applicable to the Group, which may have a material adverse effect on its financial position. The Group's ability to utilise marginal well tax credits in the United States could be or become subject to limitations (for example, if it is deemed to undergo an "ownership change" for applicable U.S. federal income tax purposes).

The nature and amount of tax that the Group expects to pay and the reliefs expected to be available to it are each dependent upon several assumptions, any one of which may change and which would, if so changed, affect the nature and amount of tax payable and reliefs available. In particular, the nature and amount of tax payable may be dependent on the availability of relief under tax treaties and is subject to changes to the tax laws or practice in any of the jurisdictions the Group currently is subject to or may be subject to in the future. Any limitation in the availability of relief under these treaties, any change in the terms of any such treaty or any changes in tax law, interpretation or practice could increase the amount of tax payable by the Group.

Finally, because the Company is an entity incorporated in the United Kingdom that is treated as a U.S. corporation for all purposes of U.S. federal income tax law, any changes in U.S. federal income tax law could negatively impact the Group's effective tax rate and cash flows, which could cause the Group's business, results of operations, financial condition, cash flows or prospects to be materially and adversely affected.

The taxation of an investment in the Ordinary Shares depends on the individual circumstances of the holders. Holders of the Ordinary Shares are strongly advised to consult their professional tax advisers.

Tax legislation may be enacted in the future that could negatively impact the Group's current or future tax structure and effective tax rates.

Long-standing international tax initiatives that determine each country's jurisdiction to tax cross-border international trade and profits are evolving as a result of, among other things, initiatives such as the Anti-Tax Avoidance Directives, as well as the Base Erosion and Profit Shifting reporting requirements, mandated and/or recommended by the European Union, G8, G20 and Organisation for Economic Cooperation and Development, including the imposition of a minimum global effective tax rate for multinational businesses regardless of the jurisdiction of operation and where profits are generated (Pillar Two). Many countries around the world, including the United Kingdom, have introduced new, or amended existing, tax laws applicable to multinational businesses to implement Pillar Two. As these and other tax laws and related regulations change (including changes in the interpretation, approach and guidance of tax authorities), the Group's financial results could be materially impacted. Given the unpredictability of these possible changes and their potential interdependency, it is difficult to assess whether the overall effect of such potential tax changes would be cumulatively positive or negative for the Group's earnings and cash flow, but such changes could cause the Group's business, results of operations, financial condition, cash flows or prospects to be materially and adversely affected.

RISKS RELATING TO THE ACQUISITION

The completion of the Acquisition is subject to the satisfaction (or waiver, if applicable) of certain conditions; and if the Acquisition does not complete because any of the conditions are not satisfied (or waived, if applicable), the Company will not realize the perceived benefits of the Acquisition.

The completion of the Acquisition is subject to the satisfaction of various customary closing conditions, including, among other things, (i) Shareholder Approval, (ii) expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, (iii) approval of the listing of the Consideration Shares by the NYSE, and (iv) the accuracy of each party's representations and warranties (subject to certain materiality qualifiers) and compliance by each party with its covenants under the Agreement in all material respects. There can be no assurance that the conditions to the closing of the Acquisition will be satisfied, waived or fulfilled in a timely fashion or that the Acquisition will be completed. Failure to satisfy or, where appropriate, obtain waiver of any of these conditions may result in the proposed Acquisition not being completed. In addition, satisfying the outstanding conditions may take longer, and could cost more, than the Company and Maverick expect. Any delay in completing the proposed Acquisition may adversely affect the Company and the benefits that the Company expects to achieve if the Acquisition is completed within the expected timeframe, which could materially and adversely affect the business, results of operations, financial condition, cash flows or prospects of the Group.

The Company's business relationships may be subject to disruption due to uncertainty associated with the Acquisition.

Parties with which the Group does business may experience uncertainty associated with the Acquisition, including with respect to current or future business relationships with Maverick, the Group or the Enlarged Group. The Group's business relationships may be subject to disruption as parties with which Maverick or the Group does business may attempt to negotiate changes in existing business relationships or consider entering into business relationships with parties other than Maverick, the Group or the Enlarged Group. These disruptions could have an adverse effect on the businesses, financial condition, results of operations or prospects of the Enlarged Group, including an adverse effect on the Group's ability to realize the anticipated benefits of the Acquisition. The risk, and adverse effect, of such disruptions could be exacerbated by a delay in completion of the Acquisition or termination of the Agreement, which could materially and adversely affect the business, results of operations, financial condition, cash flows or prospects of the Group.

The Agreement restricts the Group's ability to pursue alternatives to the Acquisition.

The Agreement contains provisions that restrict the ability of the Group to enter into a business combination with a party other than Maverick. In addition, DGOC will be required to pay the termination fee of $50 million, if the Agreement is terminated by (i) Maverick in the event that (A) the Board changes its recommendation, (B) the Company materially breaches its non-solicitation obligations, or (C) the Company fails to close the Acquisition when required under the Agreement and all closing conditions have been satisfied or waived, or (ii) the Company to accept a superior acquisition proposal, or (iii) the Company or Maverick, upon the occurrence of the outside date under the Agreement, being 30 June 2025, and at the time of termination (A) Shareholder Approval has not been obtained and (B) Maverick would have been permitted to terminate the Agreement due to a change in recommendation by the Board or the Company's material breach of its non-solicitation obligations. Further, if prior to the Company's shareholders meeting, an acquisition proposal related to the Company is publicly proposed or publicly disclosed and not withdrawn at least five business days before such meeting, and the Agreement is terminated by the Company or Maverick due to (A) the occurrence of the outside date under the Agreement, (B) a material breach by the Company of its representations, warranties or covenants, or (C) the failure to obtain the Shareholder Approval at a general meeting of the shareholders of the Company, and within 12 months after such termination, a definitive agreement is entered into with respect to a qualifying acquisition proposal or the Group consummates a qualifying acquisition proposal, then DGOC would be required to pay Maverick the Termination Fee. Any such payment of the Termination Fee could materially and adversely affect the business, results of operations, financial condition, cash flows or prospects of the Group.

Failure to complete Acquisition could negatively impact the price of the Ordinary Shares and the future business and financial results of the Group.

If the Acquisition is not completed for any reason, the ongoing businesses of the Group may be adversely affected, and without realizing any of the benefits of having completed the Acquisition, the Group would be subject to a number of risks, including the following:

- the Group may experience negative reactions from the financial markets, including negative impacts on its share price;
- the Group may experience negative reactions from its customers, vendors, business partners, regulators and employees;
- the Group will be required to pay certain costs relating to the Acquisition, whether or not the Acquisition is completed;
- the Agreement places certain restrictions on the conduct of the Group's business prior to completion of the Acquisition, and such restrictions, the waiver of which is subject to the written consent of Maverick (such consent not to be unreasonably withheld, conditioned or delayed), and subject to certain exceptions and qualifications, may delay or prevent the Group from taking certain other specified actions, responding effectively to competitive pressures or industry developments or otherwise pursuing business opportunities during the pendency of the Acquisition that the Group would have made, taken or pursued if these restrictions were not in place;
- the Group could be subject to litigation related to any failure to complete the Acquisition or related to any enforcement proceeding commenced against the Group to perform its obligations under the Agreement;
- matters relating to the Acquisition (including integration planning) will require substantial commitments of time and resources by the Group's management, which would otherwise have been devoted to day-to-day operations and other opportunities that may have been beneficial to the Group as an independent company; and
- in the event of a termination of the Agreement under certain circumstances specified in the Agreement, DGOC may be required to pay a termination fee of $50 million to Maverick.

There can be no assurance that the risks described above will not materialize. If any of those risks materialize, they may materially and adversely affect the business, results of operations, financial condition, cash flows or prospects of the Group.

The Acquisition may have a disruptive effect on the Enlarged Group.

The Acquisition has required, and will continue to require, substantial amounts of investment, time and focus from the management teams and employees of the Group. Further, the demands that the integration process may have on management time could result in diversion of the attention of the Group's management and employees from ongoing operations, pursuing other potential business opportunities and may cause a delay in other projects currently contemplated by the Group. To the extent that the Enlarged Group is unable to efficiently integrate the operations of the Group and Maverick, realize anticipated financial benefits, retain key personnel and avoid unforeseen costs or delay, there may be a material adverse effect on the business, results of operations, financial condition, cash flows or prospects of the Enlarged Group.

RISKS RELATING TO THE ORDINARY SHARES

The price of Ordinary Shares may be volatile and purchasers of the Ordinary Shares could incur substantial losses.

The public market for the Ordinary Shares has been characterised by significant price and volume fluctuations. There can be no assurance that the market price of the Ordinary Shares will not decline below its current or historic price ranges. The market price may bear no relationship to the prospects, stage of development, existence of gas and oil reserves, revenues, earnings, assets or potential of the Group and may not be indicative of its future business performance. The trading price of the Ordinary Shares could be subject to wide fluctuations. Fluctuations in the price of gas, natural gas liquids and oil and related international political events can be expected to affect the price of the Ordinary Shares. In addition, the stock market in general has experienced extreme price and volume fluctuations that have affected the market price for many companies, sometimes unrelated to the operating performance of these companies. These market fluctuations, as well as general economic, media generated, political and market conditions, may have a material adverse effect on the market price of the Ordinary Shares.

Some of the factors that could negatively affect the price of the Ordinary Shares or result in fluctuations in the price or trading volume of the Ordinary Shares include:

- operating results that vary from the Group's financial guidance or the expectations of securities analysts and investors;
- the financial performance of the major end markets that the Group targets;
- the operating and securities price performance of companies that investors consider to be comparable to the Company;
- announcements of strategic developments, acquisitions and other material events by the Group or its competitors;
- failure to meet or exceed financial estimates and projections of the investment community or that the Group provides to the public;
- initial issuance of new or updated research or reports by securities analysts;
- changes in government regulations;
- financing or other corporate transactions;
- the loss of any of the Group's key personnel;
- sales of Ordinary Shares by the Company, its executive officers and board members or its shareholders in the future;
- price and volume fluctuations in the overall stock market, including as a result of trends in the economy as a whole; and
- other events and factors, many of which are beyond the Group's control.

Many of these factors are beyond the Group's control and it is not possible to predict their potential effects on the price of the Ordinary Shares. Finally, the stock market is subject to extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to their operating performance and could have the same effect on the Ordinary Shares.

Shareholders may be subject to US withholding or income tax depending on their country of residence and their ownership percentages.

Pursuant to Section 7874 of the US Internal Revenue Code (the "**Code**"), the Company believes it is and will continue be treated as a US corporation for all purposes under the Code. Since the Company will be treated as a US corporation for all purposes under the Code, the Company will not be treated as a "passive foreign investment company", as such rules apply only to non-US corporations for US federal income tax purposes.

Due to the nature of its assets and operations, the Directors believes that the Company is (and will continue to be) a US real property holding corporation under the Code and the Ordinary Shares constitute (and the Directors expect the Ordinary Shares to continue to constitute) a US real property interest ("**USRPI**"). As a US corporation that is a US real property holding corporation, distributions paid by the Company to Non-US Holders (as defined below) are generally subject to US federal withholding taxes (at a rate of up to 30%, which may, in certain circumstances, be reduced by an applicable treaty) applied on the gross amount of such distributions. Non-US Holders generally are subject to a 15% withholding tax on the amount realised from a sale or other taxable disposition of a USRPI, such as the Ordinary Shares, which is required to be collected from any sale or disposition proceeds. Such Non-US Holders are subject to US federal income tax (at the regular rates) in respect of any gain on their sale or disposition of the Ordinary Shares and are required to file a US tax return to report such gain and pay any tax liability that is not satisfied by such withholding. However, if the Ordinary Shares are considered "regularly traded on an established securities market"(within the meaning of the Treasury Regulations) then Non-US Holders will not be subject to the 15% withholding tax on the disposition of the Ordinary Shares, even if such Ordinary Shares constitute USRPIs. Moreover, if the Ordinary Shares are considered "regularly traded on an established securities market" (within the meaning of the Treasury Regulations) and the Non-US Holder actually or constructively owns or owned, at all times during the shorter of the five-year period ending on the date of the disposition or the Non-US Holder's holding period, 5% or less of the Ordinary Shares taking into account applicable constructive ownership rules, such Non-US Holder may treat their ownership of the Ordinary Shares as not constituting a USRPI and will not be subject to US federal income tax on any gain realised upon the sale or other taxable disposition of the Ordinary Shares (in addition to not being subject to the 15% withholding tax described above) or US tax return filing requirements. However, the Company makes no representations as to whether the Ordinary Shares have been and will be treated as "regularly traded on an established securities market."

Furthermore, Sections 1471 through 1474 of the Code (commonly referred to as "**FATCA**") generally impose a 30% withholding tax on dividends on, or gross proceeds from the sale or other disposition of, the Ordinary Shares paid to a "foreign financial institution" or a "non-financial foreign entity" unless certain conditions are met. However, proposed Treasury Regulations currently eliminate FATCA withholding on payments of gross proceeds from the sale or other disposition of stock, including the Ordinary Shares, on or after January 1, 2019. While taxpayers generally may rely on these proposed Treasury Regulations until final Treasury Regulations are issued, there can be no assurance that the final Treasury Regulations will continue to eliminate withholding on such payments of gross proceeds.

A "Non-US Holder" is any beneficial owner of Ordinary Shares that is neither a "US Holder" nor an entity or arrangement treated as a partnership for US federal income tax purposes. A US Holder is any holder that, for US federal income tax purposes, is or is treated as any of the following: (1) an individual who is a citizen or resident of the United States; (2) a corporation created or organised under the laws of the United States, any state thereof, or the District of Columbia; (3) an estate, the income of which is subject to US federal income tax regardless of its source; or (4) a trust that (i) is subject to the primary supervision of a US court and the control of one or more "United States persons" (within the meaning of Section 7701(a)(30) of the Code), or (ii) has a valid election in effect to be treated as a United States person for US federal income tax purposes.

The Group incurs increased costs as a result of operating as a public company in the United States, and the Group's management devote substantial time to compliance initiatives and corporate governance practices following the NYSE listing.

As an NYSE-listed company, the Company incurs significant legal, accounting and other expenses that it did not incur prior to the NYSE listing. The Sarbanes-Oxley Act, the Dodd-Frank Wall Street Reform and Consumer Protection Act, the NYSE listing requirements of and other applicable securities rules and regulations impose various requirements on U.S. reporting public companies, including the establishment and maintenance of disclosure controls and procedures, internal control over financial reporting and corporate governance practices. The Group's management and other personnel devote a substantial amount of time to these compliance initiatives. Moreover, these rules and regulations have resulted in an increase in the legal and financial compliance costs and have made some activities more time consuming and costly.

However, these rules and regulations are often subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices.

There is no guarantee that the Company will continue to pay dividends in the future.

The ability of the Company to continue paying dividends on the Ordinary Shares, and the decision of the Board to recommend dividends is dependent upon the Company's performance and financial condition, cash requirements, future prospects, commodity prices, compliance with the financial covenants in the credit facilities of the Group, profits available for distribution and other factors deemed to be relevant at the time and on the continued health of the markets in which it operates. Further, while the Board's evaluation of the Company's ability or need to pay dividends will primarily remain a question of the foregoing factors, it will also take into account the performance of the Ordinary Shares, including relative to the Company's peer group. There can be no guarantee that the Company will continue to pay dividends in the future on the Ordinary Shares.

New Shares Admission may not occur when expected or an active trading market for the New Shares may not develop following New Shares Admission.

Applications will be made to admit the New Shares to trading on the London Stock Exchange's main market for listed securities as well as for listing on the NYSE. It is expected that admission of the Equity Raise Shares on the LSE will become effective on or around 24 February 2025 and that dealings in the Equity Raise Shares will commence as soon as practicable after 8.00 a.m. on that date, admission of the Over-Allotment Shares (if allotted and issued) on the LSE will become effective as soon as possible, and no later than within one month, after allotment of the Over-Allotment Shares (if any) and that dealings in the Over-Allotment Shares (if any) will commence as soon as practicable after 8.00 a.m. on that date, and admission of the Consideration Shares on the LSE will become effective immediately following Completion, expected to be in H1 2025 and that dealings in the Consideration Shares will commence as soon as practicable after 8.00 a.m. on that date. There can be no assurance, however, that an active trading market in the New Shares will develop following New Shares Admission, as applicable. Admission is also subject to the approval (and subject to satisfaction of any conditions on which such approval is expressed) of the FCA and New Shares Admission will become effective as soon as a dealing notice has been issued by the FCA and the London Stock Exchange has acknowledged that the New Shares will be admitted to trading, as applicable. There can be no guarantee that any conditions to which New Shares Admission is subject will be met or that the FCA will issue a dealing notice when anticipated.

Overseas shareholders may be subject to exchange rate risk.

The Ordinary Shares are denominated in pounds sterling while dividends to be paid in respect of the Ordinary Shares are declared in US dollars and payable in US dollars or pounds sterling. An investment in Ordinary Shares by an investor whose principal currency is not pounds sterling exposes the investor to foreign currency exchange rate risk. Any depreciation of pounds sterling in relation to such foreign currency will reduce the value of the investment in the Ordinary Shares or any dividends in foreign currency terms.

Shareholders in certain jurisdictions may not be able to participate in future equity offerings.

The Articles provide for pre-emption rights to be granted to shareholders in the Company in certain circumstances, unless such rights are dis-applied by a shareholder resolution. However, securities laws of certain jurisdictions may restrict the Group's ability to allow participation by shareholders in future offerings. In particular, shareholders in the United States may not be entitled to exercise these rights, unless the securities that are offered and sold are registered under the US Securities Act, or the securities are offered pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. None of the New Shares will be registered under the US Securities Act and there can be no assurance that the Company will file any registration statements for future share issues, or that an exemption to the registration requirements of the US Securities Act will be available in any case, or that the Company would seek to avail itself of any such exemption, absent which the shareholders in the United States would be unable to participate in such an issue. Securities laws of certain other jurisdictions may restrict the Company's ability to allow participation by Shareholders in such jurisdictions in any future issue of shares carried out by the Company.

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

General

The contents of this document are not to be construed as legal, business or tax advice. Recipients of this document should consult their own legal adviser, financial adviser or tax adviser for legal, financial or tax advice, as appropriate. 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 the New Shares Admission and the Group. The Company and the Directors make no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication.

When considering any investment decision you may take with respect to the Ordinary Shares, you should seek your own independent financial advice immediately from your stockbroker, bank manager, solicitor, accountant, fund manager or other independent financial adviser authorised under FSMA if you are in the United Kingdom or, if not, from another appropriately authorised independent financial adviser.

Recipients of this document may not reproduce or distribute this document, in whole or in part, and may not disclose any of the contents of this document or use any information herein for any purpose other than considering Admission. Such recipients of this document agree to the foregoing by accepting delivery of this document.

Notice to all investors

This document does not constitute, and may not be used for the purposes of, an offer to sell or an invitation to subscribe for or the solicitation of an offer to buy or subscribe for, any Ordinary Shares by any person in any jurisdiction: (i) in which such offer or invitation is not authorised; (ii) in which the person making such offer or invitation is not qualified to do so; or (iii) in which, or to any person to whom, it is unlawful to make such offer, solicitation or invitation. The distribution of this document and the offering of the Ordinary Shares in certain jurisdictions may be restricted. Accordingly, persons outside the United Kingdom into whose possession this document comes are required by the Company to inform themselves about, and to observe any restrictions as to the offer or sale of Ordinary Shares and the distribution of this document under, the laws and regulations of any territory in connection with any applications for Ordinary Shares, including obtaining any requisite governmental or any other consent and observing any other formality prescribed in such territory.

No action has been taken or will be taken in any jurisdiction by the Company or the Directors that would permit a public offering of the Ordinary Shares in any jurisdiction where action for that purpose is required, nor has any such action being taken with respect to the possession or distribution of this document other than in any jurisdiction where action for that purpose is required. Accordingly, the Ordinary Shares may not be offered or sold, directly or indirectly, and neither this document nor any other offering material or advertisement in connection with the Ordinary Shares may be distributed or published in or from any country or jurisdiction except under circumstances that will result in compliance with any and all applicable rules and regulations of any such country or jurisdictions. Any failure to comply with this restriction may constitute a violation of the securities laws of any such jurisdiction. Neither the Company nor any of the Directors accepts any responsibility for any violation of any of these restrictions by any other person.

Information not contained in this document

No person has been authorised to issue any advertisement or give any information or make any representations other than those contained in this document and, if given or made, such information or representations must not be relied upon as having been authorised or on behalf of the Company or the Sponsor. No representation or warranty, express or implied, is made by the Sponsor as to the accuracy or completeness of such information, and nothing in this document is, or shall be relied upon as, a promise or representation by the Sponsor as to the past, present or future. Subject to the requirements of the FSMA, the Listing Rules, DTRs, the UK Prospectus Regulation, the UK Prospectus Regulation Rules, and the UK Market Abuse Regulation neither the delivery of this document nor any subscription or sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Company or the Group taken as a whole since the date of this document or that the information in or incorporated by reference into this document is correct as of any time subsequent to the date hereof.

No incorporation of website information

Other than as expressly stated in this document, the contents of the Company's website or any website directly or indirectly linked to the Company's website have not been verified and do not form part of this document and investors should not rely on it or any of them.

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", "could", "would", "intend", "aim", "plan", "predict", "continue", "assume", "positioned", "may", "will", "should", "shall", "risk", their negatives 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. In particular, the statements under regarding the Company's or the Group's strategy, plans, objectives, goals and other future events or prospects are forward-looking statements. An investor should not place undue reliance on forward looking statements because they involve known and unknown risks, uncertainties and other factors that are in many cases beyond the Company's or the Group's control. By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future. The Company cautions investors that forward-looking statements are not guarantees of future performance and that its actual results of operations and financial condition, and the development of the industry in which it operates, may differ materially from those made in or suggested by the forward-looking statements contained in this document and/or information incorporated by reference into this document. In addition, even if the Company's or the Group's results of operation, financial position and growth, and the development of the markets and the industry in which the group operates, are consistent with the forward-looking statements contained in this document, these 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*" in this document, including:

- Volatility and future decreases in natural gas, NGLs and oil prices could materially and adversely affect the Group's business, results of operations, financial condition, cash flows or prospects.

- The Group conducts its business in a highly competitive industry.

- The Group may experience delays in production, marketing and transportation.

- The Group faces production risks and hazards, including severe weather events, that may affect the Group's ability to produce natural gas, NGLs and oil at expected levels, quality and costs that may result in additional liabilities to the Group.

- The levels of the Group's natural gas and oil reserves and resources, their quality and production volumes may be lower than estimated or expected.

- The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations such as plugging.

- The Group may not be able to keep pace with technological developments in its industry or be able to implement them effectively.

- A lowering or withdrawal of the ratings, outlook or watch assigned to the Group or its debt by rating agencies may increase the Group's future borrowing costs and reduce its access to capital.

- Deterioration in the economic conditions in any of the industries in which the Group's customers operate, a domestic or worldwide financial downturn, or negative credit market conditions could have a material adverse effect on the Group's liquidity, results of operations, business and financial condition that it cannot predict.

- The Group's operations are subject to a series of risks relating to climate change.

Each forward looking statement speaks only as of the date it was made and are 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 Listing Rules, the DTRs, UK Market Abuse Regulation, and the UK Prospectus Regulation Rules, 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. The Company will comply with its obligations to publish updated information as required by the FSMA, the Listing Rules, the DTRs, the UK Market Abuse Regulation, and the UK Prospectus Regulation Rules, or otherwise by law and/or by any regulatory authority, but assumes no further obligation to publish additional information.

For the avoidance of doubt, nothing in this document constitutes a qualification of the working capital statement contained in paragraph 17 of Part 7 ("*Additional Information*").

Neither the delivery of this document nor any sale made hereunder shall under any circumstances imply that there has been no change in the Company's and/or the Group's affairs or that the information set forth in this document is correct as of any date subsequent to the date hereof.

Profit forecasts

No statement in this document is intended as a profit forecast or a profit estimate and 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.

Presentation of financial information

Financial information relating to the Group

Unless otherwise indicated, financial information presented in this document relating to the Group as at and for the financial year ended 31 December 2023 and 2022 and as at and for the six-month period ended 30 June 2024 and 2023 is presented in US dollars, has been prepared in accordance with UK-adopted International Accounting Standards and the requirements of the Companies Act 2006 as applicable to companies reporting under those standards. This financial information relating to the Group has been extracted without material adjustment from the audited consolidated financial statements of the Group as at and for the year ended 31 December 2023 ("**Group 2023 Financial Statements**") and the unaudited interim condensed consolidated financial statements of the Group as at and for the six-month period ended 30 June 2024 ("**Group H1 2024 Financial Statements**") included in the annual report published by the Group for the year ended 31 January 2023 (the "**2023 Annual Report**") and the interim report published by the Company on 15 August 2024 for the six-month period ended 30 June 2024 (the "**H1 2024 Interim Report**") respectively.

Financial information relating to Oaktree

The financial information relating to the revenues and direct expenses relating to the Oaktree Assets presented in section 10 (*Acquisitions and Consolidation – Oaktree Acquisition*) of Part 1 (*Information on the Group*) of this document for the financial year ended 31 December 2023 ("**Oaktree 2023 Financial Information**") and the three-month period ended 31 March 2024 ("**Oaktree Q1 2024 Financial information**") is presented in US dollars, has been prepared in accordance with the accounting principles generally accepted in the United States of America ("**U.S. GAAP**") and has been derived from the historical financial records related to the Oaktree Assets. During the periods presented, the Oaktree Assets were not accounted for or operated as a separate entity, subsidiary, segment or division by Oaktree. Accordingly, a complete set of financial statements, including a balance sheet and statement of cash flows, prepared in accordance with U.S. GAAP is not available or practicable to prepare for the Oaktree Assets. This financial information varies from a complete income statement in accordance with U.S. GAAP in that it does not reflect certain expenses incurred in connection with the ownership and operation of the Oaktree Assets, including but not limited to depreciation, depletion and amortisation, impairments, accretion of asset retirement obligations, general and administrative expenses, interest expense and federal and state income taxes. These costs were not separately allocated to the working interests of the Oaktree Assets in Oaktree's accounting records.

The Oaktree 2023 Financial Information has not been audited in accordance with the International Standards on Auditing (UK). The Oaktree Q1 2024 Financial Information is also presented on an unaudited basis.

The financial information relating to the revenues and direct expenses relating to the Oaktree Assets for the two years ended 31 December 2022 and 31 December 2023 (the "**Circular Oaktree Financial Information**") was included in the circular dated 9 May 2024 published by the Company in connection with the Oaktree Acquisition (the "**Circular**") and is incorporated by reference into this document. The Circular Oaktree Financial Information was calculated based on revenue and direct expenses recognised in respect of the cash basis months of January 2023 to December 2023, which included the production months of November 2022 to October 2023. However, the Oaktree 2023 Financial Information presented in section 10 (*Acquisitions and Consolidation – Oaktree Acquisition*) of Part 1 (*Information on the Group*) of this document was calculated based on revenue and direct expenses recognised in respect of the cash basis months of March 2023 to February 2024, which includes the production months of January 2023 to December 2023. Save as set out above, there are no other differences in the basis of preparation of the Oaktree 2023 Financial Information and the Circular Oaktree Financial Information.

Financial information relating to the Maverick Group

Unless otherwise indicated, financial information presented in this document relating to the Maverick Group as at and for the financial year ended 31 December 2023 and 2022 and as at and for the nine-month period ended 30 September 2024 and 2023 is presented in US dollars, has been prepared in accordance with U.S GAAP. This financial information relating to the Maverick Group has been extracted without material adjustment from the audited consolidated financial statements of the Maverick Group as at and for the year ended 31 December 2023 and the unaudited interim condensed consolidated financial statements of Maverick Group as of September 30, 2024 and for the nine-month periods ended 30 September 2024 and 2023 as set out in Part 3 *(Historical Financial Information Relating to the Maverick Group*).

Rounding

Percentages and certain amounts included in this document have been rounded for ease of preparation. Accordingly, numerical figures shown as totals in certain tables may not be the exact arithmetic aggregations of the figures that precede them. In addition, certain percentages and amounts contained in this document reflect calculations based on the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

Non-IFRS measures

The Group presents certain key operating metrics that are not defined under IFRS (alternative performance measures) in this document. These non-IFRS measures are used by the Group to monitor the underlying performance of the Group's performance from period to period and to facilitate comparison with its peers. Since not all companies calculate these or other non-IFRS metrics in the same way, the manner in which the Group has chosen to calculate the non-IFRS metrics presented herein may not be compatible with similarly defined terms used by other companies. Therefore, the non-IFRS metrics should not be considered in isolation of, or viewed as substitutes for, the financial information prepared in accordance with IFRS. Certain of the key operating metrics set forth below are based on information derived from the Group's regularly maintained records and accounting and operating systems.

Definitions and reconciliation of the non-IFRS measures used in this document for the Group for the year ended 31 December 2023 and the six-month period ended 30 June 2024 are set out on pages 206 to 208 of the 2023 Annual Report and pages 42 to 44 of the H1 2024 Interim Report respectively, each of which is incorporated by reference into this document, as explained in Part 8 ("*Documents Incorporated by Reference*").

Definitions and reconciliation of the non-IFRS and non-U.S. GAAP measures used in this document for the Group and for Maverick, respectively, for the 12-month period ended 30 September 2024 are as set out below:

Adjusted EBITDA

EBITDA represents earnings before interest, taxes, depletion, depreciation and amortization. Adjusted EBITDA includes adjusting for items that are not comparable period-over-period, namely, accretion of asset retirement obligation, other (income) expense, loss on joint and working interest owners receivable, gain on bargain purchases, (gain) loss on fair value adjustments of unsettled financial instruments, (gain) loss on natural gas and oil property and equipment, costs associated with acquisitions, other adjusting costs, non-cash equity compensation, (gain) loss on foreign currency hedge, net (gain) loss on interest rate swaps and items of a similar nature. Adjusted EBITDA should not be considered in isolation or as a substitute for operating profit or loss, net income or loss, or cash flows provided by operating, investing, and financing activities. However, the Directors believe such a measure is useful to an investor in evaluating our financial performance because it (1) is widely used by investors in the natural gas and oil industry as an indicator of underlying business performance; (2) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the often-volatile revenue impact of changes in the fair value of derivative instruments prior to settlement; (3) is used in the calculation of a key metric in one of our Credit Facility financial covenants; and (4) is used by us as a performance measure in determining executive compensation.

Per-Unit Adjusted EBITDA Margin

Per-Unit Adjusted EBITDA Margin represents the amount of Adjusted EBITDA per unit of production.

The Group

The following table presents a reconciliation of the IFRS Financial measure of Net Income (Loss) to Adjusted EBITDA and Per-Unit Adjusted EBITDA Margin for each of the periods listed:

	For the twelve months ended	
	30 September 2024	**31 December 2023**
	(Amounts in 000's)	
Income (loss) available to ordinary shareholders after taxation	**$ 194,559**	**$ 759,701**
Finance costs	134,173	134,166
Accretion of asset retirement obligation	28,639	26,926
Other (income) expense	(1,022)	(385)
Income tax (benefit) expense	43,806	240,643
Depreciation, depletion and amortization	237,704	224,546
Gain on bargain purchase	—	—
(Gain) loss on fair value adjustments of unsettled financial instruments	(264,130)	(905,695)
(Gain) loss on natural gas and oil properties and equipment[(1)]	1,779	20
(Gain) loss on sale of equity interest	(18,440)	(18,440)
Unrealized (gain) loss on investment	(7,043)	(4,610)
Impairment of proved properties	41,616	41,616
Costs associated with acquisitions	13,191	16,775
Other adjusting costs[(2)]	27,684	17,794
Loss on early retirement of debt	12,284	—
Non-cash equity compensation	8,234	6,494
(Gain) on foreign currency hedge	—	521
(Gain) loss on interest rate swap	(200)	2,722
Total Adjustments	**258,275**	**(216,907)**
Adjusted EBITDA	**$ 452,834**	**$ 542,794**
Pro forma TTM adjusted EBITDA[(3)]	**$ 555,456**	**$ 549,258**
Adjusted EBITDA	$ 452,834	$ 542,794
Total Net Production (MMcfe)	283,474	299,632
Per-unit adjusted EBITDA margin ($/Mcfe)	**$ 1.60**	**$ 1.81**

Notes:

(1) Excludes (gain) loss on leasehold sales.

(2) Other adjusting costs for the year ended December 31, 2023 were primarily associated with legal and professional fees related to the U.S. listing, legal fees for certain litigation, and expenses associated with unused firm transportation agreements.

(3) Pro forma TTM adjusted EBITDA includes adjustments for respective twelve month periods to pro forma results for the full twelve-month impact of intra-period acquisitions (30 September 2024: Oaktree and Crescent Pass Energy; 30 September 2023: Tanos Energy Holdings II LLC; 31 December 2023: Tanos Energy Holdings II LLC)

Maverick

The following table presents a reconciliation of the U.S. GAAP financial measure of Net Income (Loss) to Adjusted EBITDA and per-unit adjusted EBITDA marginfor each of the periods listed:

	For the Twelve Months Ended	
	30 September 2024	31 December 2023
	(Amounts in 000's)	
Net Income (Loss)	**$ 126,448**	**$ 256,281**
Loss (gain) on commodity derivative instruments	(170,953)	(145,934)
Commodity derivative instrument settlement payments (receipts)	16,020	(46,722)
Depletion, depreciation, and amortization expense	177,793	166,488
Impairment of oil and natural gas properties	114,958	66,785
Interest expense	83,924	62,176
Restructuring costs	8,853	1,631
Gain on sale of assets	(2,274)	(1,090)
Income tax expense (benefit)	1,168	604
Other income, net	(2,968)	(1,130)
Transaction, integration and other costs	28,311	29,037
Total Adjustments	**254,832**	**131,845**
Adjusted EBITDA	**$ 381,280**	**$ 388,126**
Adjusted EBITDA	$ 381,280	$ 388,126
Total Net Production (MMcfe)	129,982	145,517
Per-unit adjusted EBITDA margin ($/Mcfe)	**$ 2.93**	**$ 2.67**

Net Debt and Net Debt-to-Adjusted EBITDA

Net Debt represents total debt as recognized on the balance sheet less cash and restricted cash. Total debt includes the Group's borrowings under the Credit Facility and the Group's borrowings under or issuances of, as applicable, our subsidiaries' securitization facilities, excluding original issuance discounts and deferred finance costs. The Directors believe Net Debt is a useful indicator of the Group's leverage and capital structure.

Net Debt-to-Adjusted EBITDA, or "Leverage" or "Leverage Ratio," is measured as Net Debt divided by adjusted trailing twelve-month EBITDA. The Directors believe that this metric is a key measure of the Group's financial liquidity and flexibility and is used in the calculation of a key metric in one of the Group's Credit Facility financial covenants.

The following tables presents a reconciliation of the IFRS and U.S. GAAP Financial measure of Total Non-Current Borrowings to the Non-IFRS and Non-U.S. GAAP financial measure of Net Debt and a calculation of Net Debt-to-Adjusted EBITDA and Net Debt-to-Pro Forma Adjusted EBITDA, respectively, for each of the periods listed:

The Group

	As at	
	30 September 2024	31 December 2023
	(Amounts in 000's)	
Total non-current borrowings	**$ 1,486,997**	**$ 1,075,805**
Current portion of long-term debt	210,213	200,822
Less: Cash	(9,013)	(3,753)
Less: Restricted cash	(49,678)	(36,252)
Net Debt	**1,638,519**	**1,236,622**
TTM Adjusted EBITDA	**452,834**	**542,794**
Pro forma TTM adjusted EBITDA(1)	**$ 555,456**	**$ 549,258**
Net debt-to-pro forma TTM adjusted EBITDA	**2.9x**	**2.3x**

Notes:

(1) Pro forma TTM adjusted EBITDA includes adjustments for respective twelve month periods to pro forma results for the full twelve-month impact of intra-period acquisitions (30 September 2024: Oaktree and Crescent Pass Energy; 30 September 2023: Tanos Energy Holdings II LLC; 31 December 2023: Tanos Energy Holdings II LLC).

Maverick

	As at	
	30 September 2024	**31 December 2023**
	(Amounts in 000's)	
Long-term debt	**$ 657,292**	**$ 697,405**
Current portion of long-term debt	110,254	113,773
LESS: Cash	(40,137)	(53,263)
LESS: Restricted cash – current	(36,736)	(31,936)
Net Debt	**690,673**	**725,979**
TTM Adjusted EBITDA	**381,280**	**388,126**
Net debt-to-adjusted EBITDA	**1.8x**	**1.9x**

Free Cash Flow

Free Cash Flow represents net cash provided by operating activities less expenditures on natural gas and oil properties and equipment and cash paid for interest. The Directors believe that Free Cash Flow is a useful indicator of the Group's ability to generate cash that is available for activities other than capital expenditures. The Directors believe that free cash flow provides investors with an important perspective on the cash available to service debt obligations, make strategic acquisitions and investments, and pay dividends.

The following tables presents a reconciliation of the IFRS and U.S. GAAP Financial measure of Net Cash from Operating Activities to the Non-IFRS and Non-U.S. GAAP financial measure of Free Cash Flow for each of the periods listed:

The Group

	For the Twelve Months Ended	
	30 September 2024	**31 December 2023**
	(Amounts in 000's)	
Net cash provided by operating activities	**$ 385,084**	**$ 410,132**
Less: Expenditures on natural gas and oil properties and equipment	(49,730)	(74,252)
Less: Cash paid for interest	(115,769)	(116,784)
Free cash flow	**$ 219,585**	**$ 219,096**

Maverick

	For the Twelve Months Ended	
	30 September 2024	**31 December 2023**
	(Amounts in 000's)	
Net cash provided by operating activities	**$ 283,317**	**$ 308,261**
Less: Expenditures on natural gas and oil properties and equipment	(161,826)	(286,420)
Less: Cash paid for interest(1)	n/a	n/a
Free cash flow	**$ 121,491**	**$ 21,841**

Notes:

(1) For the periods presented, Cash Paid for Interest is included within the calculation of Maverick Natural Resources' Net Cash Provided by Operating activities

Total Revenue, Inclusive of Settled Hedges and Adjusted EBITDA Margin

Total Revenue, Inclusive of Settled Hedges, includes the impact of derivatives settled in cash. The Directors believe that Total Revenue, Inclusive of Settled Hedges, is a useful because it enables investors to discern the Group's realized revenue after adjusting for the settlement of derivative contracts.

The following table presents a reconciliation of the IFRS financial measure of Total Revenue to the non-IFRS financial measure of Total Revenue, Inclusive of Settled Hedges and a calculation of Adjusted EBITDA Margin for each of the periods listed:

The Group

	For the Twelve Months Ended	
	30 September 2024	31 December 2023
	(Amounts in 000's)	
Total revenue	**$ 754,878**	**$ 868,263**
Net gain (loss) on commodity derivative instruments(1)	183,876	178,064
Total revenue, inclusive of settled hedges	**938,754**	**1,046,327**
Adjusted EBITDA	$ 452,834	$ 542,794
Adjusted EBITDA Margin	**48%**	**52%**
Adjusted EBITDA Margin, exclusive of Next LVL Energy	**49%**	**53%**

Notes:

(1) Net gain (loss) on commodity derivative settlements represents cash (paid) or received on commodity derivative contracts. This excludes settlements on foreign currency and interest rate derivatives as well as the gain (loss) on fair value adjustments for unsettled financial instruments for each of the periods presented.

Maverick

	For the Twelve Months Ended	
	30 September 2024	31 December 2023
	(Amounts in 000's)	
Total revenue	$ 880,107	$ 977,390
Net gain (loss) on commodity derivative instruments(1)	16,020	(46,722)
Total revenue, inclusive of settled hedges	**896,127**	**930,668**
Adjusted EBITDA	$ 381,280	$ 388,126
Adjusted EBITDA Margin	**43%**	**42%**

Notes:

(1) Net gain (loss) on commodity derivative settlements represents cash (paid) or received on commodity derivative contracts. This excludes settlements on foreign currency and interest rate derivatives as well as the gain (loss) on fair value adjustments for unsettled financial instruments for each of the periods presented.

Currency and Exchange Rate Information

In this document, unless otherwise indicated, references to "**pounds sterling**", "**sterling**", "**pounds**", "**GBP**", "**pence**", "**p**" or "**£**" are to the lawful currency of the United Kingdom, and references to "**US dollars**", "**$**" or "**US$**" are to the lawful currency of the United States.

Unless otherwise indicated, the financial information contained in this document has been expressed in US dollars. The Group prepares its financial information in US dollars.

The following table sets out, for the periods presented, the high, low, average and period-end Bloomberg Composite Rate expressed as Sterling per $1.00. The Bloomberg Composite Rate is a "best market" calculation, in which, at any point in time, the composite bid rate is equal to the highest bid rate of all currently active, contributed, bank indications, and the composite ask rate is equal to the lowest ask rate offered by these same bank indications. The Bloomberg Composite Rate is a mid-value rate between the composite bid rate and the composite ask rate. The rates may differ from the actual rates used in the preparation of the consolidated historical financial information and other financial information appearing in this document.

The average rate for a year, a month, or for any shorter period, means the average of the final daily Bloomberg Composite Rates during that year, month, or shorter period, as the case may be.

Period (Year/Month)	Period end	Average	High	Low
		(GBP per $1.00)		
2023	0.7835	0.8042	0.8452	0.7625
2024	0.7990	0.7826	0.8097	0.7454
January 2025	0.8067	0.7847	0.8218	0.7454

Source: Bloomberg

Market, Economic and Industry Data

This document relies on and refers to information regarding the Group's business and the markets in which the Group operates and competes. The market data and certain economic and industry data and forecasts used in this document were obtained from governmental and other publicly available information, independent industry publications and reports prepared by industry consultants.

Industry publications, surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, but that there can be no assurance as to the accuracy and completeness of such information. The Group believes that these industry publications, surveys and forecasts are reliable, but they have not been independently verified from third party sources.

All such data sourced from third parties contained in this document have been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading.

The Group cannot assure you that any of the assumptions underlying any statements regarding the gas and oil industry are accurate or correctly reflect the Group's position in the industry. Market data and statistics are inherently predictive and speculative and are not necessarily reflective of actual market conditions. Such statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market. In addition, the value of comparisons of statistics for different markets is limited by many factors, including that: (i) the markets are defined differently; (ii) the underlying information was gathered by different methods; and (iii) different assumptions were applied in compiling the data. Accordingly, the market statistics included in this document should be viewed with caution and no representation or warranty is given by any person as to their accuracy.

Elsewhere in this document, statements regarding the gas and oil industry are not based on published statistical data or information obtained from independent third parties, but are based solely on the Group's experience, its internal studies and estimates, and its own investigation of market conditions. The Group cannot assure you that any of these studies or estimates are accurate, and none of the Group's internal surveys or information have been verified by any independent sources. While the Group is not aware of any misstatements regarding its estimates presented herein, the Group's estimates involve risks, assumptions and uncertainties, and are subject to change based on various factors.

Presentation of Reserves

The Group reports the PV-10 value of its reserves on a yearly basis in its annual report and accounts. The PV-10 value of the reserves of the Maverick Group as set out in Part 5 (*Competent Persons Report for the Maverick Group*). The PV-10 value for the Group for the year ended 31 December 2023 and for the Maverick Group for the year ended 31 December 2024 is determined using strip pricing and the reserves information, and in each case, has been independently evaluated by the Group's independent engineers, NSAI in accordance with 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 (the "**PRMS Standards**"). In connection with the Capital Raise, the Company has filed the Registration Statement with the SEC. In this filing the SEC's disclosure rules require the inclusion of certain reserve information calculated under SEC pricing. The reserve information disclosed in the Registration Statement under SEC pricing includes: estimated proved reserves, estimated proved developed reserves, estimated proved undeveloped reserves, the SEC's standardised Measure for reserves and PV-10 as of 31 December 2023. This additional information is set out paragraph 7 (Overview of Assets and Principal Activities) of Part 1 (Information on the Group) and has not been previously reported by the Group in its annual report and accounts or otherwise and has not been independently evaluated by the Group's independent engineers, NSAI in accordance with the PRMS Standards.

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

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the Group and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of the Group's proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, micro-seismic data and well-test data.

Reserve engineering is and must be recognised as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of natural gas, NGLs and oil that are ultimately recovered. Estimates of economically recoverable natural gas, NGLs and oil and of future net cash flows are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs.

Defined terms and technical terms

Certain terms used in this document, including all capitalised terms, are defined and explained in Part 10 ("*Definitions*"). Certain technical terms are explained in Part 9 ("*Technical Terms*").

Times

All times referred to in this document are, unless otherwise stated, references to time in London, United Kingdom.

Validity

The validity of this document will expire on the date falling 12 months after the date of approval of this document, or, if earlier, the date that is the latest of the Equity Raise Shares Admission, the Over-Allotment Shares Admission and the Consideration Shares Admission. The obligation to supplement a prospectus in the event of significant new factors, material mistakes or material inaccuracies does not apply when a prospectus is no longer valid.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	David Edward Johnson (*Independent Non-executive Chair*) Robert Russell "Rusty" Hutson, Jr. (*Chief Executive Officer*) Martin Keith Thomas (*Independent Non-executive Director*) David Jackson Turner, Jr. (*Independent Non-executive Director*) Sandra (Sandy) Mary Stash (*Independent Non-executive Director and Senior Independent Director*) Kathryn Z. Klaber (*Independent Non-executive Director*)
Company Secretary	Apex Secretaries LLP 6th Floor 125 London Wall London EC2Y 5AS
Registered Office of the Company	4th Floor Phoenix House 1 Station Hill, Reading Berkshire, RG1 1NB United Kingdom
Sponsor	Stifel Nicolaus Europe Limited 150 Cheapside London, EC2V 6ET United Kingdom
Legal Advisers to the Company as to English law	Latham & Watkins (London) LLP 99 Bishopsgate London ECM2 3XF United Kingdom
Legal Advisers to the Sponsor as to English law	Ashurst LLP London Fruit & Wool Exchange 1 Duval Square London E1 6PW United Kingdom
Auditor and Reporting Accountant	PricewaterhouseCoopers LLP 1 Embankment Place London WC2N 6RH United Kingdom

EXPECTED TIMETABLE OF PRINCIPAL EVENTS AND ADMISSION STATISTICS

Each of the dates and times in the table below is indicative only and may be adjusted by the Company, in which event details of the new times and dates will be notified to the FCA and the London Stock Exchange and announced by way of an announcement issued via a RIS provider.

References to times are to London time.

Expected timetable

Registration Statement on Form F-3 is effective upon filing in the U.S. in connection with the Capital Raise	11 February 2025
Prospectus Supplement to Registration Statement on Form F-3 is filed in the U.S.	20 February 2025
Announcement confirming results of the Capital Raise and publication of Prospectus	20 February 2025
Commencement of listing of the Equity Raise Shares on the NYSE[(1)]	2.30 p.m. on 21 February 2025
Admission of the Equity Raise Shares to the Official List and commencement of dealings in Capital Raise Shares on the Main Market[(1)]	8.00 a.m. on 24 February 2025
Commencement of listing of the Consideration Shares on the NYSE	H1 2025
Admission of the Consideration Shares to the Official List and commencement of dealings in Consideration Shares on the Main Market	H1 2025

Note:

(1) If the Over-Allotment Option is exercised simultaneously with the pricing of the Equity Raise, admission of the Over-Allotment Shares will take place simultaneously as well. Otherwise, the Over-Allotment Shares (if allotted and issued) Admission will become effective as soon as possible, and no later than within one month, after allotment of the Over-Allotment Shares (if any).

Admission Statistics

Number of Ordinary Shares as at the Latest Practicable Date	51,295,942
Maximum number of Capital Raise Shares	9,513,680
Number of Equity Raise Shares issued	8,500,000
Number of Over-Allotment Shares that may be issued	850,000
Maximum number of Consideration Shares that may be issued[(1)]	33,954,491
Enlarged Issued Share Capital[(2)]	94,764,113
Capital Raise Shares as a percentage of the Enlarged Issued Share Capital[(3)]	10.04%
Consideration Shares as a percentage of the Enlarged Issued Share Capital[(2)(3)]	35.83%
New Shares as a percentage of the Enlarged Issued Share Capital[(1)]	45.87%

Notes:

(1) The consideration for the proposed Acquisition is expected to be satisfied by, among other things, the issue of 21,217,713 Ordinary Shares. While the number of Consideration Shares is subject to adjustment based on the outstanding amount of debt under Maverick's reserves-based lending facility at Completion, it is currently not anticipated that any such adjustment will be necessary. Consequently, although the Merger Agreement provides for the potential issue of up to an additional 12,736,778 Ordinary Shares, resulting in a maximum of 33,954,491 Ordinary Shares that may be issued in connection with the Acquisition, any such increase to a material extent is currently considered unlikely.

(2) Assuming that other than the New Shares (with the Over-Allotment Option being exercised in full and the maximum number of Consideration Shares being issued) to be issued in connection with the Transactions, no further Ordinary Shares are issued and allotted by the Company between the Latest Practicable Date and the date that is the latest of the Equity Raise Shares Admission, the Over-Allotment Shares Admission and the Consideration Shares Admission.

(3) Assuming that the maximum number of Consideration Shares are issued at Completion in accordance with the Merger Agreement.

PART 1
INFORMATION ON THE GROUP

The following information should be read in conjunction with the information appearing elsewhere in, or incorporated by reference in, this document, including the financial and other information in, or incorporated by reference in this document.

1. Introduction

The Company is a leading independent energy company focused on natural gas and liquids production, transportation, marketing and well retirement, primarily located within the Appalachian and Central regions of the United States. The Appalachian Basin spans Pennsylvania, Virginia, West Virginia, Kentucky, Tennessee and Ohio and consists of multiple productive, shallow conventional formations and two productive, deeper unconventional shale formations, the Marcellus Shale and the slightly deeper Utica Shale. The Company also operates in the Bossier and Haynesville shale formations and the Cotton Valley sandstones in East Texas and West Louisiana, the Barnett Shale in North Texas and the Mid-Continent producing areas across Oklahoma and Texas.

The Company was incorporated in 2014 in the United Kingdom, and the Group's predecessor business was co-founded in 2001 by the Chief Executive Officer, Robert Russell "Rusty" Hutson, Jr., with an initial focus primarily on natural gas and oil production in West Virginia. In recent years, the Group has grown rapidly by capitalising on opportunities to acquire and enhance producing assets and by leveraging the operating efficiencies that result from economies of scale and vertical integration. As of 30 June 2024, the Group had completed 25 acquisitions since 2017 for a combined purchase price of approximately $3 billion.

The Group's strategy is to acquire existing long-life assets and to make investments in those assets to improve environmental and operational performance under a modern field management philosophy and stewardship-based approach to generate cash flows and maximise shareholder returns. The Group's shareholder return-focused business model is underpinned by a disciplined commodity hedging strategy that is designed to mitigate downside price risk for the three primary commodity products that it produces and sell: natural gas, crude oil and natural gas liquids ("**NGLs**"). The Group's hedging programs are typically designed to hedge price risk for an approximate range of 70% to 90% of its production within the next 12-months and an approximate range of 50% to 70% of its production within the next 12 to 36 months. Additionally, the Group's hedge programs can extend beyond a three-year period for production volumes that support portions of its long-term debt, specifically, the Group's collective ABS Notes.

The Directors believe the combination of acquiring and operating low decline assets and a disciplined hedging programs provides the Group's shareholders with relatively predictable, reliable and sustainable cash flows. For the nine months ended 30 September 2024 and for the year ended 31 December 2023, the Group paid approximately $69 million and $168 million, respectively, to its shareholders in the form of dividends. Since the Company's initial public offering of Ordinary Shares on the London Stock Exchange in 2017 (the "**LSE IPO**"), the Company has returned approximately $879 million to shareholders in the form of dividends and share repurchases.

The Group actively seeks to acquire high-quality producing conventional and unconventional natural gas and oil assets from industry participants divesting assets either due to a desire to reallocate capital to other assets and/or to raise cash proceeds. The Group targets long-life producing assets at what the Directors view as attractive valuations, and in the Group's commercial evaluation, it typically attributes substantially all value to the proved developed producing ("**PDP**") reserves and attribute minimal, if any, value to the proved undeveloped reserves. The Group typically assigns no value to probable or possible reserves. The Group's target assets are characterised by multi-decade production profiles and low decline rates, and the Group places a particular focus on assets whose value the Directors believe can be enhanced by scale and vertical integration through complementary midstream infrastructure or by the Group's operational and marketing framework.

The Group focuses on improving the performance and operations of assets it acquires, many of which have not received significant operational focus or investment from their former owners. This improvement is achieved through the Group's deployment of rigorous field management programs and/or refreshing infrastructure. Through operational efficiencies, the Group attempts to maximise value by enhancing production while lowering costs and improving well productivity. These production enhancement techniques also enable the Group to reduce the methane emissions profile of its wells. The Group further enhances the value of its assets by leveraging its midstream gathering and transportation infrastructure, which allows the Group to diversify and expand its third-party revenue, optimise pricing, increase flow assurance and reduce third-party costs and inefficiencies.

The Group's senior management team is comprised of experienced individuals with decades of combined experience in the natural gas and oil sector. In particular, the Group benefits from the experience of its Chief Executive Officer, Rusty Hutson, Jr., who is highly experienced in sourcing accretive acquisitions and securing the related financing. The management team is complemented by talented financial and operational leadership with significant operational experience in U.S. onshore natural gas and oil basins. When the Group makes acquisitions, the Group seeks to retain experienced field-level employees who have a consistent focus on execution and an in-depth understanding of, and extensive experience working with, the Group's assets, which is enhanced under the Group's management's leadership and operating strategy.

Commitment to Operational Excellence and Environmental, Social and Governance Initiatives

The Group has adopted to stringent operating standards, with a strong focus on health, safety and the environment. The Directors believe that striving to act as a careful steward of the Group's assets will improve revenue through captured methane emissions while also reducing operating costs, which benefits the Group's profitability. This focus on operational excellence, including demonstrated reductions in methane emissions, also helps benefit the environment and communities in which the Group operates. The Group also works to extend the lives of mature wells, rather than engaging in development activity, and, through the Group's state-monitored, systematic asset retirement program, seeks to eliminate potential associated emissions by safely plugging and abandoning such wells at the end of their productive lives. The Directors believe that by deploying the Group's proprietary asset retirement infrastructure rather than engaging contractors to perform such activities unless necessary or prudent, the Group is better able to more nimbly react to operating conditions as they develop, changes in asset performance and relative changes in the emissions profiles of the Group's producing wells, thereby reducing potential methane emissions while also increasing margins and cost efficiency.

The Group's operations team developed its proprietary Smarter Asset Management ("**SAM**") program, which is focused on enhancing the Group's operational results by slowing production declines and returning shut-in wells to production through wellhead compression management, fluid load reduction and pump-jack optimisation. The SAM program underpins the Group's focus on efficient operation of its wells and midstream assets to improve production, thereby partially offsetting natural production declines, lower operating costs and emissions and improve asset integrity, all with the goal of generating higher cash flow. The Group's SAM program also seeks to reduce unintended natural gas emissions, while managing the Group's general and administrative expenses.

Throughout 2023 and through 30 June 2024, the Group has remained diligently focused on its previously stated near-term goals to reduce Scope 1 methane intensity by 30% by 2026 and by 50% by 2030 (assuming a 2020 baseline). The Group's dedicated human capital and financial investments, aimed largely at leak detection and repair efforts in its Appalachian upstream assets and conversion of natural gas-driven pneumatic devices to compressed air across its portfolio contributed to a 30% year-over-year reduction in reported methane emissions intensity for year-end 2023.

Though the Group's upstream, midstream and asset retirement business units encompass distinct activities, it views its corporate and individual employee actions through the lens of a single, unified approach that the Group calls "OneDEC", which the Directors believe drives a culture of operational excellence fostered through the integration of people and the standardisation of processes and systems. OneDEC seeks to ensure alignment of its corporate and sustainability initiatives with departmental action supported by financial investment and boots on the ground. A principal component of the Group's OneDEC culture is also its greatest asset, its employees. The Group strives to foster a corporate culture ripe with opportunities for professional collaboration and development, personal growth and enjoyment, and where all employees feel valued and supported in the work they do.

2. Strategy

The Group has the following key business strategies:

Optimisation of long-life, low-decline assets to enhance margins and improve cash flow

The Group's stewardship model focuses on acquiring existing, long-life, low-decline producing wells and, opportunistically, associated midstream assets or undeveloped acreage, and efficiently managing acquired assets through its modern field management philosophy and SAM program to improve or restore production, reduce unit-operating costs and generate consistent cash flow before ultimately retiring those assets at the end of their useful lives.

When the Group acquires new assets, it often seeks to retain many of the experienced employees who have historically operated those assets while integrating its SAM program into their day-to-day operations.

While the Group is not primarily a midstream company, it also strategically seeks to maximise the value of its producing assets through complementary midstream systems that can be fully integrated into its upstream portfolio. These assets are typically located in areas where the Group is a large producer, allowing market access to higher prices and the opportunity to reroute production when adjoining, third-party systems are constrained or would result in lower pricing for product sales. The Group also earns additional revenue for transporting third-party operators' production through its systems, effectively reducing the operating costs of the Group's midstream system and ultimately improving consolidated operating margins.

The Group intends to continue optimising its operations in a manner that prioritises the generation of cash flow. The Group's principal focus is on enhancing producing wells, not drilling new wells, thereby allowing it to optimise PDP revenues and reduce costs.

Generate consistent shareholder returns through vertical integration, strategic hedging and cost optimisation

The Group intends to continue its strategy of delivering value to shareholders through a combination of paying dividends, reinvesting in accretive growth, repaying debt and investing in its sustainability initiatives. From time-to-time, the Group will also evaluate and pursue share repurchase opportunities as incremental return of capital to its shareholders. The Group's shareholder return focus as well as the ability to incur debt purposefully structured to provide for amortisation and that reduces leverage over time, is supported by a conservative hedging strategy that seeks to substantially insulate cash flows from commodity price volatility and provide increased predictability of the Group's returns.

Since the LSE IPO, the Group has paid an aggregate of approximately \$743 million in dividends and has repurchased approximately \$135 million of the outstanding Ordinary Shares (as of 31 December 2024). The expected quarterly dividend payment of \$0.29 per Ordinary Share, on an annualised basis, currently delivers a yield in the top quartile of the FTSE 250 share index and the top decile among the Russell 2000 Index. The recommendation of dividends and approval of share repurchase programs is at the discretion of the Company's board of directors. There can be no guarantee that the Company will continue to pay dividends on the Ordinary Shares or repurchase Ordinary Shares in the future.

The Group aims to maximise shareholder value by realising operational efficiencies and the thorough implementation of vertical integration. To achieve this strategy, the Group utilises its SAM program to partially offset natural production declines and also leverage its scale and cost efficiencies in an effort to reduce unit operating costs and improve margins, particularly in respect of newly acquired assets. The Group proactively seeks to manage its operating costs and the Directors believe that there is further opportunity to reduce those costs given the Group's scale and approach to vertical integration, particularly for recently acquired assets. The Group's midstream assets also help to support cost reduction by providing operational control over the transportation of the Group's production, thereby allowing it to optimise pricing through a selection of delivery points and providing increased operational control. The Group's asset retirement infrastructure also helps provide cost efficiency in its well retirement and abandonment activities.

Disciplined growth through acquisitions of producing assets

The Group intends to maintain its disciplined approach to acquisitions focusing on acquiring assets that the Directors believe will provide long-term accretive cash flow generation. The Directors believe the Group is well positioned to benefit from ongoing trends in the U.S. exploration and production industry in which incumbent operators seek to divest non-core assets to generate capital necessary capital to drill and develop their core leasehold positions.

The Group has a track record as an established consolidator, and the Directors believe that the Group is one of the few operators in the United States of its scale focused on long-lived conventional production in the Appalachian Basin and Central Region. While the Group has historically focused on the Appalachian Basin and the Central Region, the fragmented operator landscape across the U.S. has created significant opportunity to find accretive asset packages that meet the goals of the Group's historical investment standards, primarily due to its ability to effectively apply SAM program techniques to newly acquired assets as well as leveraging favourable regional commodity pricing, ample takeaway capacity and opportunities to build accretive scale around the position.

The Group has demonstrated this strategic infill growth ability in its Central Region. Through four acquisitions in 2021 the Group quickly entered the region and began building scale. During 2022 and 2023, the Group continued this growth, as it did in the Appalachian Basin, by expanding its footprint with practical bolt-on upstream, midstream, and processing facility acquisitions. In June 2024, the Group completed one of its largest acquisitions to date, an approximately $354 million (including the assumption of debt) purchase of Oaktree's proportionate working interest in the East Texas, Tapstone, Tanos and Indigo acquisitions. In addition, in August 2024, the Group completed the acquisition of high-working interest, operated natural gas properties and related facilities located within East Texas from Crescent Pass Energy, LLC and in October 2024, the Group completed the acquisition of operated natural gas properties located within East Texas from a regional operator. The Directors believe these acquisitions provided, and will provide, the Group with additional operational scale, expense efficiencies, and increased cash flows. Additionally, the Oaktree Acquisition provided additional production volumes available for sale to the U.S. Gulf Coast LNG markets.

The Group continues to look for other opportunities that fit its investment criteria across the U.S. and will continue to opportunistically expand its footprint in accordance with its stated strategy. The Group intends to maintain disciplined target leverage ratios, seeking not to unduly burden its balance sheet with additional debt for non-accretive growth.

Maintain a strong balance sheet with ability to opportunistically access capital markets

The Group actively manages its balance sheet and seeks to maintain an appropriate long-term leverage ratio between 2.5x to 3.0x. As the Group pursues its acquisition strategy, it may incur debt which exceeds the Group's targeted long-term leverage ratio. For example, at 30 September 2024, the Group had a net debt-to-pro forma trailing twelve months ("**TTM**") Adjusted EBITDA ratio of 2.8x which reflects the financing of the strategic Oaktree Acquisition. Over time, the Directors expect this ratio to return to the Group's long-term target.

As of 30 June 2024, 84% of the Group's outstanding indebtedness had an amortising structure allowing for scheduled principal repayments. These low interest fixed-rate structures contain hedge protection for the collateralised assets supporting strong margins that are intended to secure the structured borrowing repayments. This structure allows the Group to naturally deleverage over time in a manner that complements the natural low decline nature of its asset base. The Group also seeks to maintain sufficient liquidity to capitalise on acquisition opportunities as they become available. The Group will continue to seek out future acquisitions at attractive valuations and in line with its strategy, while being conservatively capitalised in order to return to its long-term leverage ratio goal of 2.5x.

Operate assets with what the Directors believe are industry-leading sustainability initiatives

The Directors believe that natural gas is and will be a critical resource in the energy mix into the foreseeable future and will continue to play a vital role in the global and domestic energy supply. In addition to consistently implementing the Group's SAM program across its asset base, the Group strives to be at the leading edge of its industry with respect to the implementation of emissions-detection technology as well as emissions reduction targets. Some of the actions the Group has taken in an effort to reduce emissions include the deployment of technologies for methane detection and reduction and the replacement or conversion of its compressors and natural gas-driven pneumatic devices.

The Board oversees the development of the Group's climate change strategy through responsible stewardship of existing assets. To this end, the Board has established a standing Sustainability and Safety Committee whose primary focus is on evaluating issues relating to climate change, including changes in regulation and policy and other external, macro-level developments relating to climate change. The other committees of the Board are also engaged in assessing sustainability and climate-related risks within the scope of their committee role, and climate-related matters are also discussed regularly as part of the board of directors' meetings. The Group also seeks to be proactive in social stewardship and has engaged global consultants and financial advisors to assist in its efforts to produce high quality disclosures and regulatory compliance as well as sustainability ratings agencies to assist in its efforts to provide accurate and validated reported data and company actions.

3. Strengths

The Group benefits from the following key competitive strengths:

Relatively low-risk and low-cost portfolio of assets

The Group benefits from a highly diversified portfolio of relatively low-risk and low-cost assets. These assets include conventional and unconventional natural gas and oil producing wells located across Tennessee, Kentucky, Virginia, West Virginia, Ohio, Pennsylvania, Texas, Oklahoma and Louisiana. As a result of the Group's diverse asset base, the Group's performance is not materially impacted by the performance of any individual well or well pad. In addition to these upstream assets, the Group's portfolio contains approximately 17,700 miles of natural gas gathering pipelines (as of 30 June 2024) and a network of compression and processing facilities that are complementary to the Group's upstream assets and allows the Group to enhance margins by reducing third-party tariffs and optimise pricing through route selection. The Group also has agreements with third parties to gather and transport their produced natural gas, which effectively reduces the operating costs of the Group's midstream system and ultimately improves consolidated operating margins. The Group does not rely on exploration or development activity to increase reserves or drive production. As a result, it is not as exposed to the capital-intensive development and drilling risks that come with a more traditional development model. The Group's wells are mature and generally benefit from simple and low-cost maintenance operations, as illustrated by its low relative gathering and transportation cost per Mcfe. The Group's third party gathering and transportation cost for the six months ended 30 June 2024 was $0.57 per Mcfe. For the six months ended 30 June 2024, excluding acquisitions, the Group's total capital expenditures were $0.15 per Mcfe as compared to $0.21 per Mcfe for the six months ended 30 June 2023. The Group's low capital intensity reflects the low level of maintenance capital typically needed to sustain its production estimates.

Long-life and low-decline production

The Group benefits from relatively stable, long-life and low-decline production from its wells, which provides a durable, highly visible source of cash flow. This cash generation profile allows the Group to maintain a prudent allocation of cash flows consisting of dividend payments, debt reduction and organic growth reinvestment, as well as investments in sustainability initiatives and potential share repurchases. The vast majority of the Group's wells are past their high decline phase and into their period of decline at rates that are materially lower and generally demonstrate a more stable production profile. The Group's decline rate of approximately 10%, when taking into account its acquisitions completed in 2023, is lower than many public, development-focused gas-weighted exploration and production companies where decline rates in excess of 30% are not uncommon. The Group's portfolio performance is underpinned by its SAM program, which enhances production from producing wells and returns other non-producing wells to a productive state.

High margin assets benefiting from significant scale and owned midstream and asset retirement infrastructure

The Group benefits from relatively consistent production with low decline rates from its high-quality assets and significant scale that, when paired with its relatively low average cost of production, gives rise to attractive profit margins and cash flows. Corporate scale, enhanced by its acquisitions, allows the Group to leverage the extensive expertise of its work force and the experience accumulated by its employees from operating in gas-focused regions for many years, driving innovation and best practices. The Group's significant operational scale is enhanced by its vertically integrated operations, in particular its midstream infrastructure, which results in increased control of its production flow, increased operational efficiencies, and increased third-party revenue streams, as well as its asset retirement infrastructure and operations, which allow the Group to reduce costs in respect of well retirement and abandonment obligations.

Highly experienced management and operational team

The Group's senior management team is comprised of experienced individuals with a combined over 100 years of experience in the natural gas and oil sector. In particular, the Group benefits from the knowledge of its Chief Executive Officer, Rusty Hutson, Jr., who is highly experienced in sourcing accretive acquisitions and securing the related financing. The management team is complemented by a senior operational team with a deep understanding of U.S. onshore gas basins, spanning an average of over 30 years of operational experience. These experienced employees have a consistent focus on execution and an in-depth understanding of, and extensive experience working with, the Group's assets. This operational experience culminates in the Group's SAM program. The Group's management team remains focused on efficient and effective management of production and operations while carefully controlling general and administrative expenses.

Track record of successful consolidation and integration of acquired assets

Following the development of the U.S. onshore natural gas and oil industry through what is commonly referred to as the 'shale revolution', there has been a significant supply of conventional and unconventional assets that have become available as a result of a number of U.S. exploration and development companies selling producing acreage viewed as non-core to their operations, as well as distressed sellers looking to supplement low cash flow with asset sale proceeds. At the same time, this increase in the supply of assets has been met by limited demand due to market uncertainty and relatively weak capital markets. The Directors believe that the Group is well positioned to take advantage of these continued consolidation opportunities. The Group's management team has demonstrated its ability to source, fund and execute acquisitions that significantly enhance shareholder value. For example, the Group has completed 25 acquisitions since 2017 for total purchase consideration of approximately $3 billion.

A proactive and innovative approach to asset retirement

The Group takes seriously its responsibilities, its local communities and its environment. With safety and environmental stewardship as priorities, the Group has designed its asset retirement program to permanently retire wells that have reached the end of their economic lives. Unlike the higher risk, complex and costly "decommissioning" of deep, offshore wells with large production platforms, the retirement of the Group's predominantly shallow, onshore wells and their small land footprints is typically far less complex and costly.

In 2017, after the LSE IPO, the Group proactively began to meet regularly with state officials to develop a long-term plan to retire its growing portfolio of long-life wells. Engaging with the appropriate regulators, the Group designed its retirement activities with an aim to be equitable for the Group's stakeholders while placing an emphasis on the environment. This collaborative plan has resulted in 222 of the Group's wells being retired during 2023, significantly exceeding the Group's agreements with applicable states. The Group developed 10-year asset retirement plans with the states of Kentucky and Ohio and 15-year plans with the states of Pennsylvania and West Virginia.

During 2022, the Group meaningfully expanded its well retirement capabilities through a series of acquisitions and the establishment of its full service, asset retirement company, Next LVL Energy LLC ("**NLE**"). As of 30 June 2024, the NLE team consisted of 108 employees and included capabilities for the following services: well plugging, wireline, cementing, construction, transportation, well services and permitting. The NLE team represents significant portion of the asset retirement capacity in the region. These investments in the Group's retirement program have been well received by state leaders and as a result the Group has been engaged by the states of West Virginia, Ohio and Pennsylvania to use its skills, knowledge and capacity to help manage the retirement of portions of their inventory of abandoned and orphan wells. The Group aims to continue to grow these relationships as the Group further solidifies its position as a market leader in asset retirement.

The Group's asset retirement program reflects its solid commitment to a healthy environment, the surrounding community and its citizens and state regulatory authorities. It partners its highly skilled personnel with the necessary financial resources to responsibly manage the Group's assets throughout their productive lives and retirement. The Group strives to meet or exceed its annual asset retirement obligations under state agreements and has a growing track record demonstrating its ability to succeed in this effort.

4. Capital Raise

The Company has issued 8,500,000 new Ordinary Shares (the "**Equity Raise Shares**") in connection with a capital raise, raising net proceeds of up to approximately £93.9 million ($118.3 million) after deducting the underwriting discounts and commissions and estimated offering expenses payable by the Company, based on the public offering price of $14.50 per Ordinary Share, the U.S. dollar equivalent of a 3.4% discount from the closing price of the Ordinary Shares on the LSE on 19 February 2025 (based on an exchange rate of £1.00 to $0.7943). The Company may issue up to a further 850,000 new Ordinary Shares in connection the over-allotment option granted by the Company at the same price on which the Equity Raise Shares are issued. The Company has relied, and will rely, on its existing shareholder authorisations granted at the 2024 AGM to allot and issue the Capital Raise Shares and the Directors intend to use the net proceeds from the Capital Raise to repay a portion of the debt incurred by the Group in connection with the Acquisition. In the event that the Acquisition does not close, the Company intends to use the net proceeds from the Capital Raise for repayment of debt and general corporate purposes.

In connection with the Capital Raise, the Company has entered into an underwriting agreement on 19 February 2025 (the "**Underwriting Agreement**") with Citigroup Global Markets Inc. and Mizuho Securities USA LLC, acting as the representative for the underwriters in the Capital Raise (the "**Underwriters**"). Subject to the terms and conditions stated in the Underwriting Agreement, each Underwriter has severally agreed to purchase, and the Company has agreed to sell to that Underwriter, the number of Ordinary Shares set forth in the Underwriting Agreement. The Underwriting Agreement provides that the obligations of the Underwriters to subscribe for the Ordinary Shares are subject to approval of legal matters by counsel and to other conditions. The Underwriters are obligated to subscribe for all the Ordinary Shares if they subscribe for any of the Ordinary Shares.

In connection with the Capital Raise, each of the Company and directors and senior managers of the Company has agreed that, for a period of 60 days from 19 February 2025 and subject to certain exceptions (including the issuance of Ordinary Shares in connection with the closing of the pending Acquisition), each of the Company and directors and senior managers of the Company will not, without the prior written consent of Citigroup Global Markets Inc. and Mizuho Securities USA LLC, dispose of or hedge any of the Ordinary Shares or any securities convertible into or exchangeable for the Ordinary Shares.

The Company has also granted to the Underwriters an option, exercisable for 30 days from the date of the underwriting agreement to subscribe for up to 850,000 new Ordinary Shares (the "**Over-Allotment Shares**"), at the price at which the new Ordinary Shares are issued and allotted in the Capital Raise. To the extent the option is exercised, each Underwriter is required to subscribe for a number of additional Ordinary Shares approximately proportionate to that Underwriter's initial purchase commitment.

Upon completion of the Capital Raise, the Capital Raise Shares (assuming the Over-Allotment Option is exercised in full and the maximum number of Consideration Shares are issued) will represent approximately 10.04% of the Enlarged Issued Share Capital and the Equity Raise Shares (assuming no Over-Allotment Option is exercised and the maximum number of Consideration Shares are issued) will represent approximately 8.97% of the Enlarged Issued Share Capital.

In connection with the Capital Raise, the Company has filed relevant materials with the SEC, including a shelf registration statement on Form F-3, which was filed on 11 February 2025 and became effective upon filing, and a prospectus supplement, which was filed on 20 February 2025, for the registration of the offer and sale of the Capital Raise Shares under the US Securities Act by a foreign private issuer (as defined under the U.S. Securities Exchange Act of 1934, as amended) in the United States. Shareholders may obtain the Registration Statement free of charge at the SECs website, http://www.sec.gov, or for free from the Company at https://ir.div.energy/.

5. The Acquisition

On 24 January 2025, the Company and its subsidiaries, Diversified Gas & Oil Corporation ("**DGOC**") and Remington Merger Sub, LLC, entered into a merger agreement (the "**Agreement**") with Maverick Natural Resources, LLC ("**Maverick**") and EIG Management Company, LLC ("**EIG**") to acquire Maverick, a portfolio company of EIG.

Pursuant to the terms of the Agreement, the gross transaction value is approximately $1,275 million, and the consideration is expected to be satisfied as follows:

- **Cash**: cash consideration of approximately $207.1 million, to be funded from the Company's existing Credit Facility;

- **Consideration Shares**: issue of 21,217,713 Ordinary Shares to the unitholders of Maverick, including EIG, valued at approximately $345 million as of the date of the execution of the Agreement; and

- **Assumption of debt**: assumption of approximately $700 million of Maverick's debt outstanding associated with its reserves based lending facility, an ABS amortising note and other outstanding credit.

The mix of cash and Consideration Shares are subject to adjustment, based on the outstanding amount of debt under Maverick's reserves based lending facility at Completion in excess of $200 million.

The Company has also received commitments for the increase of the borrowing base of the Group's Credit Facility to $900 million at Completion to reflect the Acquisition and it is expected that the maturity of the Credit Facility will also be extended to four years following Completion.

The Board believes the Acquisition would provide the Group with significantly increased scale, long-term free cash generation, superior unit cash margins, low decline production base, a compelling environmental profile, and a robust regional consolidation opportunity.

Background to and reasons for the Acquisition

The proposed Acquisition is expected to combine two complementary asset packages, pairing high-quality proved developed producing weighted production with the lowest corporate decline and capital intensity among peers, to create the Enlarged Group which is expected to generate substantial distributable free cash flow, delivering strong, consistent shareholder value creation through disciplined debt reduction, a sustainable dividend, and strategic share repurchases.

The key reasons for the proposed Acquisition are:

- **Value Maximising Contribution**: The Acquisition is expected to be financially and strategically accretive to key metrics including cash flow, leverage, and valuation multiples and is expected to deliver significant benefits through enhanced margins, expense synergies, and strengthened cost of capital for the Enlarged Group.

- **Strong Financial Position, Liquidity and Capital Markets Access:** The Acquisition is expected to be leverage-accretive that integrates additional investment-grade ABS notes which will also provide for a natural deleveraging process for the Enlarged Group. Further, the additional size and scale will enhance the Enlarged Group's trading liquidity and access to capital markets, bolstering its ability to efficiently finance its business and pursue bolt-on accretive acquisitions.

- **Multi-Basin Exposure and Scale:** The Group's position in core geographies across Appalachia, the Western Anadarko, Permian, Barnett, and Ark-La-Tex regions will be further enhanced with commodity product diversification and beneficial exposure to oil markets to create a more resilient market cycle risk profile and durable revenue. This multi-basin scale will also provide capital investment optionality for organic growth by acquisition or growth by high returns joint venture partnership development projects.

- **Unique Operational Approach:** The Group focuses on responsible operations and stewardship of existing energy infrastructure assets, including well optimization and managing the assets by leveraging technology, vertical integration, and scale to the ultimate end of life. By leveraging the complementary operations focus, utilizing technology, aligning resources, and sharing expertise, the Directors believe that the Enlarged Group will optimize performance, extract substantial value, and drive growth. Further, the unique and differentiated business model of Maverick offers reliable production, multi-basin commodity diversification and a strong hedging program that enables consistent cash flows for the Enlarged Group.

- **Commitment to Stewardship and Environmental Performance:** The Enlarged Group will focus on achieving tangible targets, and dedicated actions to drive sustainability, transparency, and environmental progress through asset improvement and optimization practices, data-driven innovation of ongoing measurement, monitoring, and mitigation of emissions.

- **Proven Process to Capture Synergies:** The Directors believe that the Group's established integration processes and corporate infrastructure will unlock significant and sustainable value with fast, effective and efficient integration and is expected to provide expense savings and a meaningful earnings contribution for the Enlarged Group. Further, the modern field management philosophy of the experienced management team of the Group is well positioned to leverage technology, capture synergies and unlock portfolio value following the Acquisition.

Summary information on Maverick

Maverick is a private oil and gas company headquartered in Houston, Texas. Maverick specialises in the management of mature upstream assets through application of automation and data-science technology while focusing on safety, emissions, and environmental responsibility.

The key operating and financial metrics for each of the Group and Maverick for the twelve month period ended 30 September 2024 (unless otherwise noted) are set out below:

USD, rounded in millions unless stated otherwise	Group	Maverick
Production (Mmcfe/d) (1)	~850	~350
Commodity Mix	~ 85% Natural Gas ~15% Liquids	~45% Natural Gas ~55% Liquids
Total Revenue	\$755	\$880
Total Revenue, Inclusive of Settled Hedges (2)	\$939	\$896
Net Income	\$195	\$126
Adjusted EBITDA (3)	\$555	\$381
Net cash provided by operating activities	\$385	\$279
Free Cash Flow (4)	\$220	\$123
EV/EBITDA (5)	4.5x	3.3x
Leverage (6)	2.9x	1.8x
PV-10 of Total Proved Reserves (7)	~3.9 billion	~2.1 billion
PV-10 of PDP Only (7)	~3.9 billion	~1.7 billion
Per-unit Adjusted EBITDA margin (\$/Mcfe)(8)	\$1.60	\$2.93

Notes:

1. The production (Mmcfe/d) for the Group and Maverick represents the exit rate as of 30 September 2024.
2. Total revenue, inclusive of settled hedges, includes the impact of derivatives settled in cash.
3. The pro forma TTM Adjusted EBITDA for the Group includes adjustments for the impact of intra-period acquisitions (30 September 2024: Oaktree, Crescent Pass Energy; 30 September 2023: Tanos Energy Holdings II LLC; 31 December 2023: Tanos Energy Holdings II LLC) undertaken by the Group
4. Free Cash Flow represents net cash provided by operating activities less expenditures on natural gas and oil properties and equipment and cash paid for interest.
5. The Group's Enterprise Value / Adjusted EBITDA ("**EV/EBITDA**") multiple is calculated using Adjusted EBITDA for the twelve-month period ended 30 September 2024 (pro forma) and enterprise value as at 17 January 2025; Maverick's EV/EBITDA multiple is based on the gross acquisition value divided by the acquisition's Adjusted EBITDA for the twelve-month period ended 30 September 2024.
6. Leverage is measured as net debt divided by Adjusted EBITDA; as used herein, net debt represents total debt as recognized on the balance sheet less cash and restricted cash at 30 September 2024.
7. PV-10 for the Group is as reported in the Company's annual report for the year ended 31 December 2023 adjusted to reflect the impact of the Oaktree Acquisition, the Crescent Pass Acquisition and the East Texas Assets Acquisition; PV-10 for Maverick is calculated using historical production data, asset-specific type curves and an effective date of 1 June 2024 using the 10-year NYMEX strip as at 10 January 2025 and excluding assets divested in October of 2024.
8. The Per-unit Adjusted EBITDA margin (\$/Mcfe) is calculated as the Adjusted EBITDA divided by the total production. Adjusted EBITDA presented for the twelve-month period ending 30 September 2024; Adjusted EBITDA for Maverick excludes certain non-recurring items primarily relating to restructuring and other transactional costs and is not adjusted for the divestiture of East Texas assets subsequent to the measurement period; Adjusted EBITDA for the Group includes the annualized effect of acquisitions performed during the measurement period.

The gross assets of Maverick as at 30 September 2024 amounted to \$1.9 billion. For the twelve-month period ended 30 September 2024, revenue and other income items of Maverick was \$1.1 billion and \$(3) million, and net income (loss) was \$126 million.

Principal terms of the Acquisition

Agreement

A. Background

On 24 January 2025, the Company and its subsidiaries, DGOC and Remington Merger Sub, LLC, entered into the Agreement with Maverick and EIG to acquire Maverick, a portfolio company of EIG, through a merger of Remington Merger Sub, LLC, a newly formed subsidiary of DGOC, with and into Maverick, with Maverick surviving the merger as a subsidiary of DGOC.

B. Consideration

The gross transaction value is approximately $1,275 million, and the consideration is expected to be satisfied as follows:

- **Cash**: cash consideration of approximately $207.1 million, to be funded from the Company's existing Credit Facility;
- **Consideration Shares**: issue of 21,217,713 Ordinary Shares to the unitholders of Maverick, including EIG, valued at approximately $345 million as of the date of the execution of the Agreement; and
- **Assumption of debt**: assumption of approximately $700 million of Maverick's debt outstanding associated with its reserves based lending facility, an ABS amortising note and other outstanding credit.

The mix of cash and Consideration Shares are subject to adjustment, based on the outstanding amount of debt under Maverick's reserves based lending facility at Completion in excess of $200 million.

C. Conditions

Completion is subject to various customary closing conditions, including, among other things,

- approval of the allotment and issue of the Consideration Shares by the shareholders (the "**Shareholder Approval**");
- expiration of the waiting period under the U.S. Hart-Scott-Rodino Antitrust Improvements Act of 1976;
- approval of the listing of the Consideration Shares by the NYSE and applications having been made to each of the FCA and the LSE for Consideration Shares Admission; and
- the accuracy of each party's representations and warranties (subject to certain materiality qualifiers) and compliance by each party with its covenants under the Agreement in all material respects.

D. Warranties and indemnities

The Agreement contains customary representations, warranties and covenants for a transaction of this nature. Maverick has given warranties in relation to, among other things, capacity, certain corporate matters, bankruptcy, litigation, existing contractual arrangements, capitalisation and ownership of its assets, affiliate arrangements, no undisclosed liabilities, indebtedness and absence of changes since the effective time. The Company has given limited warranties in relation to, among other things, capacity, certain corporate matters, bankruptcy, and sufficiency of funds to complete the Acquisition.

E. Conduct prior to Completion

The Agreement also contains customary pre-closing covenants, including the obligation of each of the Group and Maverick to use commercially reasonable efforts to conduct their respective businesses in the ordinary course in all material respects consistent with past practice and to refrain from taking certain specified actions without the consent of the other party.

The Agreement provides that, during the period from the date of the Agreement until Completion, each of the Company and Maverick will be subject to certain restrictions on their ability to solicit or respond to alternative business combination proposals from third parties, to provide non-public information to third parties and to engage in discussions with third parties regarding alternative business combination proposals. The Company's non-solicitation covenant is subject to customary exceptions for a public company.

F. Termination Rights, Termination Fee and Expenses

The Agreement contains certain termination rights for the Company and Maverick, including:

- upon mutual written consent;
- for either the Company or Maverick, if:
    - the closing of the Acquisition is not consummated by 30 June 2025, the outside date under the Agreement;
    - a final non-appealable order enjoining the Acquisition is entered into by any governmental entity; or
    - the Shareholder Approval is not obtained upon a vote at the Company's shareholders meeting;
    - as applicable, the other party breaches its covenants, representations or warranties such that any of the related closing conditions in the Agreement would not be satisfied, subject to a specified cure period;
- for Maverick, if
    - prior to receipt of the Shareholder Approval, the Board makes a change of recommendation, does not include its recommendation in the shareholder circular or publicly proposes to do the foregoing, or the Company materially breaches its non-solicitation obligations, or
    - all closing conditions have been satisfied or waived but the Company fails to close when required under the Agreement or
- for the Company, at any time prior to the receipt of Shareholder Approval, in order to substantially concurrently with such termination enter into a definitive agreement with respect to a superior acquisition proposal for the Group.

The termination rights are subject to important qualifications.

The Agreement further provides that, if the Agreement is terminated by:

- Maverick in the event that (A) the Board changes its recommendation, (B) the Company materially breaches its non-solicitation obligations, or (C) the Company fails to close the Acquisition when required under the Agreement and all closing conditions have been satisfied or waived, or
- the Company to accept a superior acquisition proposal, or
- the Company or Maverick, upon the occurrence of the outside date and at the time of termination (A) Shareholder Approval has not been obtained, and (B) Maverick would have been permitted to terminate the Agreement due to a change in recommendation by the Board or the Company's material breach of its non-solicitation obligations,

DGOC will be required to pay Maverick a termination fee equal to $50 million (the "**Termination Fee**").

If:

- prior to the Company's shareholders meeting, an acquisition proposal related to the Company is publicly proposed or publicly disclosed and not withdrawn at least five business days before such meeting,
- the Agreement is terminated by the Company or Maverick due to (A) the occurrence of the outside date under the Agreement, (B) a material breach by the Company of its representations, warranties or

covenants, or (C) the failure to obtain the Shareholder Approval at the Company's shareholders meeting, and

- within 12 months after such termination, a definitive agreement is entered into with respect to a qualifying acquisition proposal or the Company or any of its subsidiaries consummates a qualifying acquisition proposal,

then DGOC would be required to pay Maverick the Termination Fee.

If the Agreement is terminated because of a failure to receive Shareholder Approval, and a Termination Fee is not then payable, DGOC will be required to pay to Maverick up to $9,000,000 as reimbursement for fees and expenses incurred by Maverick in connection with the Acquisition. In no event will DGOC be required to pay the Termination Fee on more than one occasion, and if Maverick is entitled to receive the Termination Fee after it has already received an expense reimbursement, the Termination Fee will be paid net of the expense reimbursement received.

G. Governing Law

The Agreement is governed by the laws of the State of Delaware, United States.

Registration Rights Agreement

At Completion, the Company will enter into a registration rights agreement with Maverick unitholders receiving at least 1% of the Ordinary Shares outstanding as at Completion pursuant to which the Company will agree to, on the terms set forth therein, file with the U.S. Securities and Exchange Commission a registration statement registering for resale of Ordinary Shares comprising the Consideration Shares. The registration rights agreement provides for a lockup of six months for 33% of the Consideration Shares, nine months for an additional 33% of the Consideration Shares, and one year for the remaining 34% of Consideration Shares.

Relationship Agreement

At Completion, the Company will enter into a relationship agreement with EIG pursuant to which, for so long as EIG (together with its affiliates) holds, in the aggregate:

- no fewer than 20% of the Ordinary Shares in the Company, EIG shall be entitled to nominate for appointment two non-executive directors to the Board, and

- fewer than 20% but no fewer than 10% of the Ordinary Shares in the Company, EIG shall be entitled to nominate for appointment one non-executive director to the Board.

The Relationship Agreement will be governed by English law.

6. New Shares Admission

In order for the Company to comply with its obligations under the Listing Rules, the entire class of Ordinary Shares must be admitted to the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange's Main Market. Therefore, the Company is required to publish this Prospectus only in connection with admission of the Capital Raise Shares and the Consideration Shares to listing on the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange's Main Market. It is anticipated that Equity Raise Shares Admission will become effective at approximately 8.00 a.m. (London time) on or around 24 February 2025, Over-Allotment Shares Admission will become effective as soon as possible, and no later than within one month, after allotment of the Over-Allotment Shares (if any) and the Consideration Shares Admission will become effective immediately following Completion, expected to be in H1 2025.

This Prospectus does not constitute an offer or invitation to any person to subscribe for or purchase any Ordinary Shares in the Company.

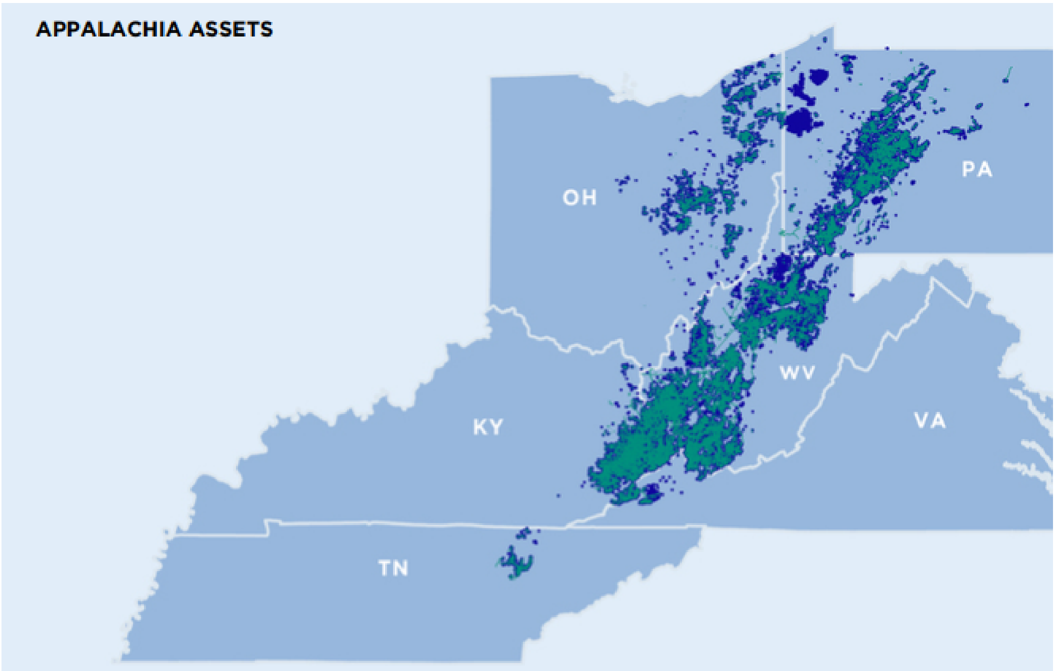
The Company also intends to apply to list the New Shares for trading on the NYSE. The Registration Statement for the registration of the Capital Raise Shares was effective upon filing with the SEC on 11 February 2025. Following completion of the Acquisition, the Company will file a Registration Statement on Form F-3 with the SEC to cover future sales by holders of the Consideration Shares.

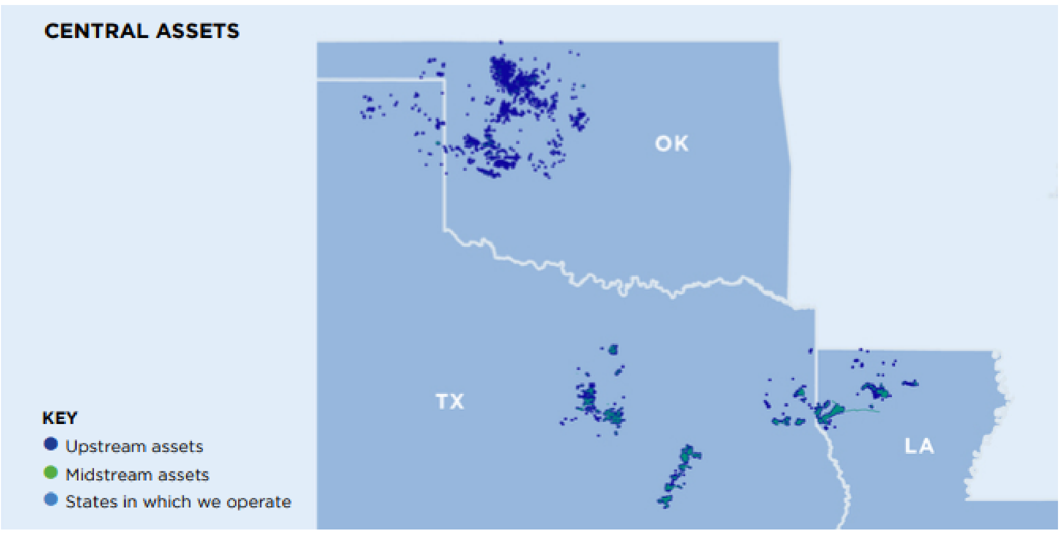
7. Overview of Assets and Principal Activities

The Group has historically operated within the Appalachian Basin, which covers an area of 185,500 square miles. While the area came to prominence following the discovery of significant shale gas reserves in 2009 in the Utica and Marcellus Shales, it has been a major producer of natural gas, NGLs and oil from conventional vertical well development since the late 19th century, making it the oldest producing basin within the United States. Through a series of acquisitions beginning in 2021, the Group obtained its first assets in the Central Region and since then, has quickly expanded its footprint and built significant scale.

The Group's asset base is comprised of approximately 74,515 conventional and unconventional natural gas and oil producing wells on a gross productive basis, as of 30 June 2024. These mature wells benefit from simple and low-cost maintenance operations and generally require low ongoing capital expenditures. The Group's well portfolio exhibits an average long-term decline rate of approximately 10% and contains certain wells that have an expected life of greater than 50 years. In addition to the upstream assets, the Group's portfolio contains approximately 17,700 miles of natural gas gathering pipelines and a network of compression stations and processing facilities.

The map below shows the geographic locations of the Group's assets as of 30 June 2024.





The Group has sought to position itself as a consolidator of mature producing assets, and the Directors believe that the Group is one of the few operators in the United States of its scale focused on long-lived conventional production in the Appalachian Basin and Central Region. The Group's goal is to replicate the success achieved to date in each of these regions, as the Directors believe there are considerable growth opportunities across the North American landscape.

The Group focusses on producing natural gas, NGLs and oil from established conventional and mature unconventional wells. The Group had average daily production of 746 MMcfepd for the six months ended 30 June 2024. Based on the Group's operational experience with its assets, the Directors believe that many of the wells in the Group's inventory have low-risk, up-hole potential that has yet to be fully quantified. Additionally, most of the Group's acreage is held by production. Due to the significant well control and geologic understanding of the Group's portfolio, the Directors believe there is also potential for significant, low-cost, low-risk developmental drilling opportunity within the Group's assets that could be pursued through joint venture arrangements, a sale of the Group's undeveloped acreage, targeted internal development programs or farm-out agreements with other operators. The Group regularly evaluates opportunities to further extract value from its acreage portfolio.

The production profiles of the wells across these formations demonstrate similar characteristics. Most of these formations produce natural gas and/or oil on a hyperbolic curve with an initial rapid decline followed by gradual decline of production over a long period of time. This modest, later-life rate of decline enables the Group to plan for the future production profile of its producing assets.

The PV-10 value of reserves for the Group as at 31 December 2023 is $3.2 billion. The following table provides the Group's reserves, PV-10 and the Standardised Measure.

	SEC Pricing[(1)]	NYMEX Strip Pricing[(2)]
Estimated Proved Reserves[(1)] (*as of 31 December 2023*)		
Natural gas (MMcf)	3,200,044	3,542,974
Natural gas liquids (MBbl)	95,701	96,718
Oil (MBbl)	12,616	12,827
Total (MMcfe)[(3)]	3,849,946	4,185,958
PV-10[(4)]	$ 2,139,690	$ 3,176,974
Standardised measure of discounted future net cash flows	1,745,536	
Estimated Proved Developed Reserves		
Natural gas (MMcf)	3,184,499	3,527,424
Natural gas liquids (MBbl)	94,391	95,408
Oil (MBbl)	12,380	12,591
Total (MMcfe)[(3)]	3,825,125	4,161,131
Estimated Proved Undeveloped Reserves		
Natural gas (MMcf)	15,545	15,550
Natural gas liquids (MBbl)	1,310	1,310
Oil (MBbl)	236	236
Total (MMcfe)[(3)]	24,821	24,827

Notes:

(1) The Group's reserves, Standardised Measure and PV-10 are calculated using SEC rules regarding reserve reporting currently in effect, including the use of an average price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("**SEC Pricing**"). For natural gas volumes, the average Henry Hub spot price was adjusted for gravity, quality, local conditions, gathering and transportation fees, and distance from market. For oil and NGL volumes, the average WTI price as of 31 December 2023 was similarly adjusted for gravity, quality, local conditions, gathering and transportation fees, and distance from market. All prices are held constant throughout the lives of the properties.

(2) The Group's reserves are calculated in accordance with the PRMS Standards, based on NYMEX Strip Pricing, as reported in the Company's annual report for the year ended 31 December 2023.

(3) Assumes a ratio of six Mcf of natural gas per Bbl.

(4) The PV-10 of the Group's proved reserves as of December 31, 2023, was prepared without giving effect to taxes or hedges. PV-10 is a non- GAAP and non-IFRS financial measure and generally differs from the "standardised measure of future net cash flows," the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net cash flows. The Directors believe that the presentation of PV-10 is relevant and useful to the Group's investors as supplemental disclosure to the standardised measure because it presents the discounted future net cash flows attributable to the Group's reserves prior to taking into account future corporate income taxes and the Group's current tax structure. While the standardised measure is dependent on the

unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that neither PV-10 nor the standardised measure represents an estimate of the fair market value of the Group's proved reserves.

The following table presents production for the Group for the year ended 31 December 2023 and for the six months ended 30 June 2024.

	30 June 2024	31 December 2023
Production		
Natural Gas (MMcf)	114,409	256,378
NGLs (MBbls)	2,829	5,832
Oil (MBbls)	730	1,377
Total production (MBoe)	**135,763**	**299,632**

The Group operates in four primary fields:

- Appalachia, which is comprised of the stacked Marcellus and Utica shales;
- East Texas and Louisiana, which consists of the stacked Cotton Valley, Haynesville, and Bossier shales;
- the Barnett Shale; and
- the Midcontinent region, in North Texas and Oklahoma, which also consists of various stacked plays.

The following table presents production for the Group's Appalachian region, which is considered significant, or greater than 15% of the Company's total proved reserves.

	31 December 2023
Production	
Natural Gas (MMcf)	167,930
NGLs (MBbls)	3,018
Oil (MBbls)	394
Total production (MBoe)	**188,402**

8. Reserves

Productive Wells

Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which the Group has an interest, operated and non-operated, and net wells are the sum of the Group's fractional working interest owned in gross wells. The following table summarises the Group's productive natural gas and oil wells as of 31 December 2023.

	As of 31 December 2023
Total gross productive wells	**74,515**
Natural gas wells	71,471
Oil wells	3,044
Total net productive wells	**60,639**
Natural gas wells	59,226
Oil wells	1,413

	As of 31 December 2023[(1)]
Total gross in progress wells	**4.0**
Total net in progress wells	**3.8**

Note:

(1) Comprised of wells in the Appalachian Region.

Exploratory and Development Drilling Activities

Information regarding the Group's drilling and development activities is set forth below:

	Development					
	Productive wells		Dry wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2023	4	4	–	–	4	4
2022	5	2	–	–	5	2

The Group has drilled no exploratory wells (productive or dry) during the years ended 31 December 2023 and 2022.

During 2022, the Group then to participate in seven development opportunities on a non-operating basis in the Appalachian Region. All seven of the Appalachian development wells remained in progress as of 31 December 2022. As of the date of this document, two of the Appalachian development wells have been completed and five remain in progress.

Developed and Undeveloped Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which the Group owned an interest as of 31 December 2023. Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. Approximately 99.9% of the Group's acreage was held by production at 31 December 2023. 'Held by production' means that the lease does not expire as long as the land is still producing.

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
5,600,383	3,039,447	8,005,314	5,519,159	13,605,697	8,558,606

Notes:

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

The undeveloped acreage numbers presented in the table above have been compiled using best efforts to review and determine acreage that is not currently drilled but may be available for drilling at the current time under certain circumstances. Whether or not undrilled acreage may be drilled and thereafter produce economic quantities of oil or gas is related to many factors which may change over time, including oil and gas prices, service vendor availability, regulatory regimes, midstream markets, end user demand, and macro and micro financial conditions; the undeveloped acreage described herein is presented without an opinion as to economic viability, as a result of the aforesaid factors. Additionally, it is noted that certain formations on a land tract may be already developed while other formations are undeveloped.

The following table sets forth the number of total gross and net undeveloped acres as of 31 December 2023 that will expire in 2024, 2025 and 2026 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Gross	Net
2024	5,404	663
2024	24,906	2,876
2026	2,869	87

The Group's primary focus is to operate its existing producing assets in a safe, efficient and responsible manner. However, the Group also assesses areas subject to lease expiration for potential development opportunities when prudent. As of 31 December 2023, the Group had no development plans other than the in-progress wells described above and therefore have not classified any other potential undrilled locations on this acreage as proved undeveloped reserves.

9. Production Volumes, Average Sales Prices and Operating Costs

	30 June 2024	30 June 2023	31 December 2022	31 December 2023
Production				
Natural Gas (MMcf)	114,409	131,868	255,597	256,378
NGLs (MBbls)	2,829	2,981	5,200	5,832
Oil (MBbls)	730	738	1,554	1,377
Total production (MMcfe)	**135,763**	**154,182**	**296,121**	**299,632**
Average daily production (MMcfepd)	746	852	811	821
% Natural gas (Mcfe basis)	84%	86%	86%	86%
Average realised sales price				
(*excluding impact of derivatives settled in cash*)				
Natural gas (Mcf)	$ 1.83	$ 2.54	$ 6.04	$ 2.17
NGLs (Bbls)	25.07	22.53	36.29	24.23
Oil (Bbls)	76.97	73.57	89.85	75.46
Total (Mcfe)	**$ 2.48**	**$ 2.96**	**$ 6.33**	**$ 2.68**
Average realised sales price				
(*including impact of derivatives settled in cash*)				
Natural gas (Mcf)	$ 2.58	$ 2.96	$ 2.98	$ 2.86
NGLs (Bbls)	23.82	23.39	19.84	26.05
Oil (Bbls)	70.49	68.44	72.00	68.44
Total (Mcfe)	**$ 3.05**	**$ 3.31**	**$ 3.30**	**$ 3.27**
Revenue (in thousands)				
Natural gas	$ 209,008	$ 334,588	$ 1,544,658	$ 557,167
NGLs	70,935	67,159	188,733	141,321
Oil	56,185	54,294	139,620	103,911
Total commodity revenue	**$ 336,128**	**$ 456,041**	**$ 1,873,011**	**$ 802,399**
Midstream revenue	17,416	16,662	32,798	30,565
Other revenue	15,130	14,602	13,540	35,299
Total revenue	**$ 368,674**	**$ 487,305**	**$ 1,919,349**	**$ 868,263**
Gain (loss) on derivative settlements (in thousands)				
Natural gas	$ 86,035	$ 55,741	$ (782,525)	$ 177,139
NGLs	(3,561)	2,569	(85,549)	10,594
Oil	(4,725)	(3,785)	(27,728)	(9,669)
Net gain (loss) on commodity derivative settlements[(1)]	**$ 77,749**	**$ 54,525**	**$ (895,802)**	**$ 178,064**
Total revenue, inclusive of settled hedges	**$ 446,423**	**$ 541,830**	**$ 1,023,547**	**$ 1,046,327**
Per Mcfe Metrics				
Average realised sales price (including impact of derivatives settled in cash)	**$ 3.05**	**$ 3.31**	**$ 3.30**	**$ 3.27**
Midstream and other revenue	0.24	0.20	0.16	0.22
LOE	(0.73)	(0.72)	(0.62)	(0.71)
Midstream operating expense	(0.26)	(0.22)	(0.24)	(0.23)
Employees, administrative costs and professional services	(0.30)	(0.25)	(0.26)	(0.26)
Recurring allowance for credit losses	–	–	–	(0.03)
Production taxes	(0.15)	(0.20)	(0.25)	(0.21)
Transportation expense	(0.31)	(0.32)	(0.40)	(0.32)
Proceeds received from leasehold sales	0.05	0.04	0.01	0.08
Adjusted EBITDA per Mcfe	**$ 1.59**	**$ 1.84**	**$ 1.70**	**$ 1.81**
Adjusted EBITDA Margin	49%	52%	49%	52%
Other financial metrics (in thousands)				
Adjusted EBITDA	$ 217,787	$ 282,864	$ 502,954	$ 542,794
Operating profit (loss)	$ 2,391	$ 909,656	$ (671,403)	$ 1,161,051
Net income (loss)	$ 15,745	$ 630,932	$ (620,598)	$ 759,701

Note:

(1) Net gain (loss) on commodity derivative settlements represents cash (paid) or received on commodity derivative contracts. This excludes settlements on foreign currency and interest rate derivatives as well as the gain (loss) on fair value adjustments for unsettled financial instruments for each of the periods presented.

10. Acquisitions and Consolidation

The Group continues to identify attractive acquisition and investment opportunities to purchase additional producing assets in or around its existing footprint, as well as outside of the states in which the Group currently operates. Each target acquisition is evaluated within strict criteria and the Group's disciplined approach to evaluating opportunities seeks to ensure that it pursues only those acquisitions that possess a consistent asset profile, significant upside, and have the potential to drive positive cash flow per share accretion. In addition, the Group also considers the emissions profiles of target acquisitions in its evaluations. Volatile commodity price environments and recent industry consolidations create market opportunities to build on the Group's strategy of value-accretive acquisitions as other companies seek exit strategies to divest non-core assets creating the necessary capital to drill and develop their core leasehold positions. The Group continues to explore opportunities and anticipates being active in a strong M&A market consistent with its proven strategy and successful track record of integrating and optimising newly acquired assets.

Oaktree Acquisition

In June 2024, the Company announced the completion of its acquisition (the "**Oaktree Acquisition**") of the proportionate working interest in certain assets within the Company's Central Region from Oaktree Capital Management L.P. (the "**Oaktree Acquisition**"). The gross purchase price for this acquisition was $410 million and after customary purchase price adjustments, the net purchase price was approximately $377 million.

The Oaktree Acquisition provided the Group with PDP reserves of 510 Bcfe (approximately 85 MMBoe) and a PDP PV-10 of approximately $462 million. The PDP reserves values (including volumes, PV-10 and approximate PV value) are calculated using an effective date of 1 November 2023 based on the 10-year NYMEX strip as at 8 March 2024. The purchase price represents a multiple of 3.0x based on the net purchase price and estimated 2024 Adjusted EBITDA (unhedged) for the assets, and a PV17 valuation on PDP-only assets, based on engineering reserves assumptions using historical cost assumptions and NYMEX strip as of 8 March 2024 for the 12 month period ended 31 December 2024 and including the estimated impact of settled derivative instruments and excluding the impact of any projected or anticipated synergies that may occur subsequent to acquisition.

The revenues and direct operating expenses for the Oaktree Assets for the year ending 31 December 2023 were $152 million and $87 million respectively, and for the three-month period ending 31 March 2024 were $35 million and $19 million respectively. The excess of revenues over direct operating expenses for the Oaktree Assets for the year ending 31 December 2023 and the three-month period ending 31 March 2024 were $65 million and $16 million respectively. For further details of the financial information of the Oaktree Assets, please see section entitled "*Presentation of Financial and Other Information – Presentation of Financial Information*" and Part 4 (*Unaudited Pro Forma Financial Information*) of this document.

Crescent Pass Acquisition

In August 2024, the Company announced the completion of its acquisition (the "**Crescent Pass Acquisition**") of high-working interest, operated natural gas properties and related facilities located within eastern Texas (the "**Crescent Pass Assets**") from Crescent Pass Energy. The gross consideration for this acquisition amounted to $101 million and after customary purchase price adjustments. The net consideration for the acquisition of the Crescent Pass Assets comprised the issue of 2,249,650 new Ordinary Shares to a designated holder of Crescent Pass (subject to a customary commercial lock-up agreement), and cash consideration of $71 million.

The Crescent Pass Acquisition provided the Group with PDP reserves of approximately 170 Bcfe (approximately 28 MMBoe) and a PDP PV-10 of approximately $155 million. The PDP reserves values (including volumes, PV-10 and approximate PV value) are calculated using historical production data, asset-specific type curves and an effective date of 1 May 2024 and based on the 4-year NYMEX strip at 18 June 2024 with terminal price assumptions of $3.94/MMBtu and $68.06/Bbl for natural gas and oil, respectively. The Crescent Pass Acquisition provided the Group with 190,000 net acres, the majority of which is held by production. The purchase price represents a multiple of approximately 3.8x, based on the net purchase price and the estimated next twelve months Adjusted EBITDA (unhedged) of $26 million and excluding the impact of any projected or anticipated synergies that may occur subsequent to acquisition.

East Texas Assets Acquisition

In October 2024, the Company announced the completion of the acquisition of operated natural gas properties located within East Texas (the "**East Texas Assets**") from a regional operator. The East Texas Assets contain a significant proved developed producing reserves purchased by the Group for approximately $69 million before customary purchase price adjustments and the net consideration for the East Texas Assets consisted of a combination of the allotment and issue of 2,342,445 Ordinary Shares and cash consideration of $41 million. Concurrently, an active third-party development company with operations in East Texas purchased an additional amount of undeveloped acreage of approximately 50,000 acres (net) for approximately $19 million, with the Group maintaining only a minority 5% interest in the undeveloped acreage (approximately 2,500 acres (net)).

The PDP net production of the East Texas Assets is 21 MMcfepd (4 MBoepd), based on estimated average daily production for October 2024 and historical performance and engineered type curves for the East Texas Assets. The East Texas Assets complement the Group's industry-leading corporate declines and capital intensity and have primarily gas-weighted production with approximately 69% gas volumes, based on engineering reserves assumptions using historical cost assumptions and NYMEX strip as of 12 August 2024 for the twelve months ended 30 September 2025. The estimated EBITDA for the next twelve months PDP production is approximately $19 million, with PDP reserves of 70 Bcfe (12 MMboe) and PV-10 of $89 million, calculated using historical production data, asset-specific type curves and with an effective date of 1 June 2024 and based on the NYMEX strip at 12 August 2024 through December 2026, with WTI held flat at $70.00/bbl and Henry Hub held flat at $3.61/MMBtu thereafter.

The net PDP purchase price represents a PV-18 valuation and the acquisition completed in October 2024.

11. Operations

Customers

The Group's production is generally sold on month-to-month contracts at prevailing market prices. During the year ended 31 December 2023, no customers individually comprised more than 10% of total revenues.

Because alternative purchasers of oil and natural gas are readily available, the Directors believe that the loss of any of these purchasers would not result in a material adverse effect on the Group's ability to sell future oil and natural gas production. In order to mitigate potential exposure to credit risk, the Group may require from time to time for the Group's customers to provide financial security.

Delivery commitments

The Group has contractually agreed to deliver firm quantities of natural gas to various customers, which it expects to fulfill with production from existing reserves. The Group regularly monitors its proved developed reserves to ensure sufficient availability to meet these commitments. The following table summarises the Group's total gross commitments, compiled using best estimates based on the sales strategy of the Group, as of 31 December 2023.

	Natural Gas (MMcf)
2024	70,769
2025	16,658
2026	—
Thereafter	360,114

Transportation and Marketing

Diversified Energy Marketing, LLC, the Company's wholly owned marketing subsidiary, provides marketing services and contractual pipeline capacity management services primarily for the Group's benefit, but also to certain third parties.

The Group's transportation infrastructure is diversified and allows it to capitalise on strengthening markets while also providing reliable takeaway capacity. This is principally achieved through the Group's vertically integrated midstream systems and the synergistic nature of its asset base. As a result, the Group's midstream infrastructure allows for access to advantageous pricing year-round and flow assurance while entering into minimal firm transportation agreements.

When prudent, however, the Group enters into arrangements that capture opportunities related to the marketing and transportation of natural gas, NGLs and oil, which primarily involve the marketing of the Group's own equity production and that of royalty owners that hold interests in its wells. Additionally, from time-to-time, the Group assumes firm transportation agreements when acquiring wells.

The Group's midstream systems, as well as its arrangements, allow it to access growing high-demand markets in the U.S. Gulf Coast region while low-cost transportation on northeast pipelines allows it to capture in-basin pricing. Certain of the Group's capacity agreements contain multiple extension and reduction options that allow it to adjust its transportation infrastructure as necessary for its production or to capture future market opportunities. As of 31 December 2023, the Group's transportation arrangements provide access to 515 MMcfepd of takeaway capacity. These firm transportation agreements may require minimum volume delivery commitments, which the Directors expect to principally fulfill with production from existing reserves.

To date, the Group has not experienced significant difficulty in transporting or marketing its natural gas, NGLs and oil production as it becomes available; however, there is no assurance that the Group will always be able to transport and market all of its production. See "*Risk Factors —The Group may experience delays in production, marketing and transportation*."

Competition

The Group's marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than the Group. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. The Directors believe that the Group's ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with customers.

Seasonality

Demand for natural gas and oil generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies and consumers procurement initiatives can also lessen seasonal demand fluctuations. Seasonal anomalies can increase competition for equipment, supplies and personnel and can lead to shortages and increase costs or delay the Group's operations.

Title to Properties

The Directors believe that the Group has satisfactory title to substantially all of its active properties in accordance with standards generally accepted in the oil and natural gas industry. The Group's properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which the Directors believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring producing wells, the Group endeavors to perform a title investigation on an appropriate portion of the properties that is thorough and is consistent with standard practice in the natural gas and oil industry.

Generally, the Group conducts a title examination and performs curative work with respect to significant defects that it identifies on properties that it operates. The Directors believe that the Group has performed reasonable and protective title reviews with respect to an appropriate cross-section of its operated natural gas and oil wells.

12. Capital Expenditure and Liquidity

The majority of the Group's ongoing capital expenditures are focused on its midstream operations, which includes pipelines and compression, while the remaining capital expenditures are focused on production optimisation, technology, upstream operations, well retirement expansion, fleet, emissions reductions initiatives, and when prudent, may include development activities targeted at replacing production. Given the Group's operational focus to acquire and operate mature conventional wells and unconventional wells with a shallow decline rate, it does not incur the significant capital expenditures associated with drilling and completion activities that would typically be incurred by other development focused exploration and production companies.

In 2023, the Company paid an annual dividend of $3.50 per share which represents a 3% increase from 2022, resulting in a payment of an aggregate total amount of approximately $168 million in dividends during 2023. In conjunction with the Oaktree Acquisition and following the Company's capital allocation policy review, on 19 March 2024, the Board of Directors recommended a dividend of $0.29 per Ordinary Share quarterly, $1.16 per Ordinary Share annually. There can be no guarantee that the Company will continue to pay dividends in amounts consistent with historical practice or at all.

The Group continues to seek to generate and increase free cash flow. The Directors plan to maintain the Group's hedging strategy and take advantage of market opportunities to raise the floor price of the Group's risk management program. The Group will seek to retain its strategic advantages in purposeful growth through a disciplined capital expenditure program that continues to secure relatively low-cost financing that supports acquisitive growth while maintaining low leverage and ample liquidity. In addition, the Group intends to remain proactive in its sustainability endeavours by continuing to include sustainability initiatives in future capital allocation decisions.

13. Recent developments and trends affecting the Company

On 11 February, 2025, the Company announced its trading results for the year ended 31 December 2024. For the year ended 31 December 2024, the average net daily production for the Group was 791 MMcfedp (132 Mboepd), the Adjusted EBITDA for the Group was approximately $470 million with an Adjusted EBITDA Margin of 50 per cent., and the Adjusted Free Cash Flow was $210 million with an Adjusted Free Cash Flow Yield of 33 per cent. The Total Revenue per unit for the Group was $3.21/Mcfe ($19.28/Boe) and the Adjusted Operating Cost per unit was $1.70/Mcfe ($10.22/Boe) for the year ended 31 December 2024. Further, in 2024, the Group generated approximately $42 million in cash flow through divestiture of certain of its undeveloped leasehold, repaid approximately $200 million in debt and returned approximately $105 million to shareholders, including $21 million in share buybacks.

Since 30 June 2024, the Group has undertaken the following transactions:

- in June 2024, the Company announced the completion of the Oaktree Acquisition;
- in August 2024, the Company announced the completion of the Crescent Pass Acquisition;
- in October 2024:
  - o the Group announced the completion of the East Texas Assets Acquisition;
  - o the Group agreed to complete a pipeline swap with a third party with the Group paying approximately $11 million for this swap, expected to close in February 2025.
- in December 2024:
  - o the Group entered into an agreement to sell certain undeveloped acreage to a third party for approximately $30 million, expected to close in the H1 2025;
  - o the Group entered into an agreement to buy producing assets from a third party for $45 million, expected to close in February 2025; and
  - o the Group entered into a letter of intent to acquire approximately 1,000 miles of pipeline and associated obligations for which the Group will receive payment of approximately $18 million.

The Company has also issued 8,500,000 new Ordinary Shares in connection with a Capital Raise, raising net proceeds of approximately £93.9 million ($118.3 million) after deducting the underwriting discounts and commissions and estimated offering expenses payable by the Company, based on the public offering price of $14.50 per Ordinary Share, the U.S. dollar equivalent of a 3.4% discount from the closing price of the Ordinary Shares on the LSE on 19 February 2025 (based on an exchange rate of £1.00 to $0.7943). The Directors intend to use the net proceeds from the Capital Raise to repay a portion of the debt incurred by the Group in connection with the Acquisition. In the event that the Acquisition does not close, the Company intends to use the net proceeds from the Capital Raise for repayment of debt and general corporate purposes.

In connection with the Capital Raise, the Company has filed relevant materials with the SEC, including a shelf registration statement on Form F-3, which was filed on 11 February 2025 and became effective upon filing, and a prospectus supplement, which was filed on 20 February 2025, for the registration of the offer and sale of the Capital Raise Shares under the US Securities Act by a foreign private issuer (as defined under the U.S. Securities Exchange Act of 1934, as amended) in the United States. Shareholders may obtain the Registration Statement free of charge at the SECs website, http://www.sec.gov, or for free from the Company at https://ir.div.energy/.

The Company has also received commitments for a $900 million four-year credit facility which incorporates both the existing Credit Facility and the new assets from Maverick as collateral. The amended and restated credit facility will provide necessary liquidity for the cash consideration of the Acquisition and to refinance the Maverick Credit Facility. Additionally, the Company intends to undertake potential refinancings related to other credit products outside of the Credit Facility.

14. Employees

As at 31 December 2023, the Group had 1,603 full-time employees, comprising 1,214 production employees and 389 production support employees located in ten states in the U.S.

15. Environmental, Health and Safety

Overview

Environmental, health, and safety ("**EHS**") management remains a top priority for the Company, and the Group demonstrates its commitment to environmental stewardship in the communities in which it operates.

The Directors believe that good business includes improving the safety of assets the Group has acquired, eliminating and reducing fugitive emissions, consolidating duplicative pipeline networks, eliminating excessive compression facilities and extending the lives of producing wells in order to offset the need to generate supply from newly drilled wells. The Group seeks to take a rigorous approach to managing the potential impacts of production fluid spills, which may include natural gas liquids, oil or produced water. Proper waste management and protection of biodiversity are of high importance to the Group, and it continuously works to mitigate or manage any impact from these spills.

The board of directors and employees have a shared commitment to becoming good and trusted stewards of the environment, to ensure that the Group's operations meet or exceed all applicable EHS standards, and to achieve EHS excellence.

The Group expects a similar commitment to safety and environmental stewardship from its business partners with whom it conducts business, so it utilises a leading supply chain risk management firm to help the Group pre-screen contractors with high safety performance records and then to continuously monitor the contractors' performance for ongoing compliance with its own expectations as well as with state and federal operating standards.

Total Recordable Incident Rate

The Group strives to maintain a zero-harm working environment and remain steadfast in its commitment to improving safety performance throughout its footprint. The goal of the Group's occupational health and safety program is to foster a safe and healthy occupational environment for employees and other stakeholders that encounter its operations. Health and safety is a top priority for the Group and is underscored by its operating performance, as well as its daily operational goals of promoting "*Safety—No Compromises*." The Group's Total Recordable Incident Rate ("**TRIR**"), defined as the sum of lost time injuries, restricted work injuries and medical treatment injuries per 200,000 work hours, and represents all injuries that require medical treatment in excess of simple first aid, in 2023 of 1.28 exceeded its goal of 1.03 and 2022 results of 0.73 and was driven by an increase in the total number of incidents, which were attributable in part to short service employees with less than one year of service under the Group's safety culture, which the Group is seeking to address through its safety programs. As with any kind of company incident, the Group's senior operations and EHS leadership teams review results with a specific emphasis on root causes and change improvements to mitigate future incidents. These mitigation efforts are shared with all employees, whether new to the Company following an acquisition or a long-term employee, to help ensure improved performance in the future.

Lost Time Incident Rate

The Group's Lost Time Incident Rate ("**LTIR**"), defined as the sum of lost time injuries per 200,000 work hours was 1.04 in 2023.

Preventable Motor Vehicle Accident Rate

With more than 1,200 employees on the road each day, road safety awareness and safe driving are of paramount importance to the Group; its goal is zero preventable vehicle incidents. Given the Group's expansive asset portfolio across the Appalachian Basin and Central Region, its well tenders and other field employees often spend a significant portion of their days driving. The Group realised a significant improvement in its preventable Motor Vehicle Accident ("**MVA**") Rate, defined as the rate of preventable accidents that occurred during the year per million miles driven by its field personnel, in 2023. The Group is proud of this accomplishment given the more than 24 million miles driven by its employees during the course of the year largely as a result of the often rural and widespread nature of its asset base and the additional staff members that joined the Company from its 2022 acquisitions. The improvement in the Group's MVA rate can be attributed to its widespread emphasis on safety in its operations, including driving, the use of dedicated training modules and its Safe Passages recognition program for drivers who achieve an accident-free driving record during the calendar year.

Reportable Spills

A spill is the introduction into the environment, other than as authorised and whether intentional or unintentional, of a substance that has the potential to cause adverse effects to the environment, human health or infrastructure. A reportable spill is one that must be disclosed to any regulatory agency where the Group operates. Intensity rate reflects the reportable volume of oil and produced water spills divided by the total gross volume of oil and produced water handled during the period.

The continued expansion of the Group's operating footprint through Central Region acquisitions has resulted in an increased volume of water produced and handled in its operations due to the geological nature of the formations in the Central Region when compared to Appalachia and the higher concentration of unconventional wells. As a result, the Group experienced a corresponding increase in the absolute volume of reportable spills compared to prior years of operations, which excluded Central Region operations. The Group aims for zero spills and continues to seek process enhancements, safety procedures and training to manage and reduce the number of spills in the future.

The Group's exposure to significant spills of liquid products is inherently low given its current production profile of 86% dry natural gas. Nonetheless, the Group seeks to take a rigorous approach to managing any impact of a potential fluid spill and implements practices and processes to minimise or eliminate such spills.

Socio-Economic Contribution

The Group's community investments are designed to make long-lasting, positive impacts on the communities where it operates. The Directors want the Group's actions and economic contributions to make a difference. The Group starts with employing local people to do local work wherever possible, specifically individuals who care about the communities and environments in which they work and live, and that demonstrate passion in how they approach and accomplish their work every day.

The Group is committed to balancing its business needs with the needs of the communities in which it and its employees operate. Between 2022 and 2024, the Group has continued to develop company-wide programs to enhance its community outreach, including a new grant-giving program and an employee wellness program. In response to the Group's community outreach and engagement work, the Group have contributed to nearly 140 different organisations that included childhood education, with emphasis on STEM (science, technology, engineering and math), secondary and higher education, children and adult physical and mental health and wellness, environmental stewardship and biodiversity, fine arts for children, food banks and meal programs, homeless shelters, community and volunteer first responders, and local infrastructure.

Approach to Sustainability

The Group's approach to sustainability management encompasses consideration of its climate, environmental and social impacts as well as its responsibility to conduct business in accordance with high standards of governance. Through the Group's commitment to stakeholder engagement and regular consideration of internal and external feedback, the Group seeks to proactively manage the topics most important to its business and corporate strategy. The Group's objectives to improve and address these key areas have served as the foundation of the Group's sustainability efforts and strategy, informing where progress should be tracked and new forward-looking targets should be set.

The Group's sustainability programs are bolstered by a unique business model focused on two key environmental stewardship approaches which keep its net zero ambitions at the forefront of its decision-making. First, the Group's operational approach to owned assets centres on investments in improving or restoring production, optimising the integrity and efficiency of its assets and reducing emissions before safely and permanently retiring those assets at the end of their productive life. Additionally, the Group's approach to new acquisition utilises intentional consideration of the emissions profile and geographic location of target assets in determining their compatibility with the Group's portfolio and the Group's emissions reduction goals. In doing so, the Group is able to recognise the immediate accretive benefit of the acquisitions to its emissions profile or to develop a near-term plan to achieve those benefits.

Throughout 2022, the Group remained diligently focused on its previously stated near-term goals to reduce Scope 1 methane intensity by 30% by 2026 and by 50% by 2030 (assuming a 2020 baseline). The Group's dedicated human capital and financial investments aimed largely at leak detection and repair efforts in its Appalachian upstream assets and conversion of natural gas-driven pneumatic devices to compressed air across its portfolio contributed to a 20% reduction in reported methane emissions intensity for year-end 2022.

While the Group's current environmental focus is on methane reductions, it also continued work on its marginal abatement cost curve ("**MACC**") to help share the Group's Scope 1 and 2 net zero greenhouse gas ("**GHG**") emissions goals. Further, the Group is endeavouring to partner its MACC efforts with a new process aimed at building and maintaining real-time emissions intelligence through the Iconic Air platform in order to enhance the accuracy and power of predictive analytics related to the Group's emissions, thus offering management potential access to better data and more tools for more informed decision-making.

Though the Group's upstream, midstream and asset retirement business units encompass distinct activities, the Group's views its corporate and individual employee actions through the lens of a single, unified 'OneDEC' approach that drives a culture of operational excellence fostered through the integration of people and the standardisation of processes and systems. The Group's OneDEC approach is an effort centered around supporting and encouraging company-wide initiatives by ensuring alignment of the Group's corporate and sustainability initiatives with departmental action supported by financial investment and boots on the ground. Thus, the Group embeds its strategic frameworks, values and stewardship business model in its OneDEC culture to align the organisation, its goals and its priorities around continued progress.

The Directors view sustainability through the dual lens of seeking to create long-term value for the Group's stakeholders and to ensure that the Group's daily actions contribute to a sustainable environment and planet for society at large. When the Group aligns its stewardship-focused business model and OneDEC culture with its commitment to sustainability, the Group is doing so with this dual lens in mind.

The Group challenges itself to consider these topics and more when it effectuates its business model, corporate strategy, sustainability commitments, daily operations and risk management practices.

Human Capital Management

As of 31 December 2023, the Group had 1,603 full-time employees.

The Group has an experienced and professional workforce and continue to grow rapidly through successful acquisitions and, in doing so, the Group welcomed approximately 21 new employees in 2023. The vast majority of its employee base consists of production employees, including its upstream and midstream field personnel. All other employee positions, including back office, administrative and executive positions, are production support roles.

As part of a coordinated diversity and engagement strategy within the Group's recruitment processes, the Group has engaged a number of external agencies across specific geographic areas of focus within its operating footprint in support of driving diversity within the Group. The percentage of women in the Group's employee base at 31 December 2023 was 11%, with the majority of such women serving in production support roles. The composition of the Group's employee workforce is a reflection of the employees that it retains from the sellers at the time of acquisitions. When coupled with a total annual turnover rate of approximately 17.1%, the Group's opportunity to further diversify its workforce is somewhat limited. Nonetheless, the Group seeks to generate a diverse candidate pool from which it can identify and hire the most qualified individuals, regardless of gender, to the benefit of the Company and its stakeholders.

The board of directors consists of three females and four males. As at 31 December 2023, the Group's senior management, including its executive committee and its direct reports but excluding the executive director, consisted of 103 employees, including 35 females (34%) and 68 males (66%). Although the board of directors do not currently have any ethnically diverse members, it acknowledges the guidelines and recommendations set forth by the Parker Review Committee. The board of directors continues to demonstrate diversity in a wider sense, with directors from the U.S. as well as the UK, bringing a range of domestic and international experience to the Board. The directors will continue to review and evaluate the Company's board and committee composition and intend to continue further progress with independence and diversity, particularly in light of President Trump and the Republican-led Congress' stated intentions to diverge from the prior administration's positions on key issues like the so-called "methane fee".

16. Government Regulation

General

The Group's operations in the United States are subject to various federal, state and local (including county and municipal level) laws and regulations. These laws and regulations cover virtually every aspect of the Group's operations including, among other things: use of public roads; construction of well pads, impoundments, tanks and roads; pooling and unitisations; water withdrawal and procurement for well stimulation purposes; wastewater discharge, well drilling, casing and hydraulic fracturing; stormwater management; well production; well plugging; venting or flaring of natural gas; pipeline construction and the compression and transportation of natural gas and liquids; reclamation and restoration of properties after natural gas and oil operations are completed; handling, storage, transportation and disposal of materials used or generated by natural gas and oil operations; the calculation, reporting and payment of taxes on natural gas and oil production; and gathering of natural gas production. Various governmental permits, authorisations and approvals under these laws and regulations are required for exploration and production as well as midstream operations. These laws and regulations, and the permits, authorisations and approvals issued pursuant to such laws and regulations, are intended to protect, among other things: air quality; ground water and surface water resources, including drinking water supplies; wetlands; waterways; protected plants and wildlife; natural resources; and the health and safety of the Group's employees and the communities in which it operates.

The Group endeavours to conduct its operations in compliance with all applicable U.S. federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, non-compliance during operations can occur. Certain non-compliance may be expected to result in fines or penalties, but could also result in enforcement actions, additional restrictions on the Group's operations, or make it more difficult for the Group to obtain necessary permits in the future. The possibility exists that new legislation or regulations may be adopted which could have a significant impact on the Group's operations or on its customers' ability to use the Group's natural gas, natural gas liquids and oil, and may require the Group or its customers to change their operations significantly or incur substantial costs.

Environmental Laws

Many of the U.S. laws and regulations referred to above are environmental laws and regulations, which vary according to the jurisdiction in which the Group conducts its operations. In addition to state or local laws or regulations, the Group's operations are also subject to numerous federal environmental laws and regulations. Below is a discussion of some of the more significant federal laws and regulations applicable to the Group and its operations.

Clean Air Act

The federal Clean Air Act and analogous state laws and federal and state regulations regulate air emissions primarily through permitting and/or emissions control requirements. This affects natural gas production and processing operations. Various activities in the Group's operations are subject to regulation, including pipeline compression, venting and flaring of natural gas, and hydraulic fracturing and completion processes, as well as fugitive emissions from operations. The Group obtains permits from the responsible authority, typically state or local authorities, to conduct these activities. Additionally, the Group is often required to obtain pre-approvals for construction or modification of certain facilities, to meet stringent air permit requirements, or to evaluate and use specific equipment, technologies or best management practices in order to reduce, control, or minimize emissions. Further, emissions from certain proximate and related sources may need to be aggregated to provide for regulation and permitting of a single, major source. Federal and state governmental agencies continue to investigate the potential for emissions from oil and natural gas activities, and further regulation could increase the Group's cost or temporarily restrict its ability to produce. For instance, in December 2023, the Environmental Protection Agency ("**EPA**") finalised regulations establishing new comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from new and existing operations in the oil and gas sector, including the exploration and production, transmission, processing and storage segments. The rule was published on 8 March 2024 and became effective 7 May 2024. Additionally, the Inflation Reduction Act, which was signed into law in August 2022, included a "methane fee" on methane emissions from oil and gas operations based on certain emissions intensity thresholds. There is ongoing litigation in the D.C. Circuit regarding the implementation of such rules, and the Trump Administration may diverge from the prior Biden Administration's positions including by promulgating new or amended regulations. The impact of future regulatory and legislative developments, if adopted or enacted, could result in increased compliance costs, increased utility costs, additional operating restrictions on the Group's business and an increase in the cost of products generally. Although such costs may impact the Group's business directly or indirectly by impacting its facilities or operations, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding the additional measures and how they will be implemented.

Clean Water Act

The federal Clean Water Act ("**CWA**"), corresponding state laws, and federal and state regulations affect the Group's operations by regulating storm water or other discharges of substances, including pollutants, sediment, and spills and releases of oil, brine and other substances, into surface waters, and in certain instances imposing requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. The discharge of pollutants into jurisdictional waters is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers, or a delegated state agency. These permits typically require regular monitoring and compliance with effluent limitations, and include reporting requirements. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Endangered Species and Migratory Birds

The federal Endangered Species Act, corresponding state laws, and federal and state regulations restrict activities in the U.S. that may impact plant and animal species that are threatened or endangered and their critical habitat. The Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act provides similar protections to migratory birds and bald and golden eagles, respectively and their nests and eggs. Some of the Group's operations are located in areas that are or may be designated as protected habitats for endangered or threatened species, or in areas where migratory birds or bald and golden eagles are known to exist. Laws and regulations intended to protect threatened and endangered species, migratory birds, or bald and golden eagles could have an impact on the Group's construction activities and operations. New or additional species that may be identified as requiring protection or consideration could also lead to prohibitions, delays or increased expense in obtaining permits for operations and/or other restrictions may be imposed, including operational restrictions.

Safety of Gas Transmission and Gathering Pipelines

Natural gas pipelines serving the Group's operations are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("**PHMSA**") pursuant to the Natural Gas Pipeline Safety Act of 1968, ("**NGPSA**"), as amended by the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002 ("**PSIA**"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "**2011 Pipeline Safety Act**"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas. Additionally, certain states, such as West Virginia, also maintain jurisdiction over intrastate natural gas lines. In October 2019, PHMSA finalised the first of three rules that, collectively, are referred to as the natural gas "Mega Rule." The first rule imposed additional safety requirements on natural gas transmission pipelines, including maximum operating pressure and integrity management near HCAs for onshore gas transmission pipelines. PHMSA finalised the second rule extending federal safety requirements to onshore gas gathering pipelines with large diameters and high operating pressures in November 2021. PHMSA published the final of the three components of the Mega Rule in August 2022, which took effect in May 2023. The final rule applies to onshore gas transmission pipelines, clarifies integrity management regulations, expands corrosion control requirements, mandates inspection after extreme weather events, and updates existing repair criteria for both HCA and non-HCA pipelines. Finally, PHMSA published a Notice of Proposed Rulemaking regarding more stringent gas pipeline leak detection and repair requirements to reduce methane emissions on 18 May 2023. A final rule was issued on 17 January 2025, aimed at requiring pipeline operators to establish advanced leak detection programs aimed at detecting and repairing gas leaks.

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act ("**RCRA**") and corresponding state laws and regulations impose requirements for the management, treatment, storage and disposal of hazardous and non- hazardous wastes, including wastes generated by the Group's operations. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of natural gas and oil are currently regulated under RCRA's solid (non-hazardous) waste provisions. However, legislation has been proposed from time to time, and various environmental groups have filed lawsuits, that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent handling, disposal and clean-up requirements.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act ("**CERCLA**" or "**Superfund**") imposes joint and several liability for costs of investigation and remediation, and for natural resource damages without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, so-called potentially responsible parties ("**PRP**"), include the current and past owners or operators of a site where the release occurred and anyone who disposed, transported, or arranged for the disposal, transportation, or treatment of a hazardous substance found at the site. CERCLA also authorised the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment, and to seek to recover from the PRPs the costs of such action. Many states, including states in which the Group operates, have adopted comparable state statutes.

Although CERCLA generally exempts "petroleum" from regulation, in the course of the Group's operations, it has generated and will generate wastes that may fall within CERCLA's definition of hazardous substances, and may have disposed of these wastes at disposal sites owned and operated by others. The Group may also be the owner or operator of sites on which hazardous substances have been released. In the event contamination is discovered at a site on which the Group is or has been an owner or operator, or to which it has sent hazardous substances, the Group could be jointly and severally liable for the costs of investigation and remediation and natural resource damages. Further, it is not uncommon for neighbouring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Oil Pollution Act

The primary federal law related to oil spill liability is the Oil Pollution Act ("**OPA**"), which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defences exist to the liability imposed by OPA, they are limited.

Regulation of the Sale and Transportation of Natural Gas, NGLs and Oil

The transportation and sale, or resale, of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission ("**FERC**") under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and terms and conditions of service, which affects the marketing of natural gas that the Group produces, as well as the revenues it receives for sales of its natural gas. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil and refined products and certain other liquids be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from regulation by FERC. However, the distinction between federally unregulated gathering facilities and FERC regulated transmission facilities is a fact-based determination, and the classification of facilities is the subject of ongoing litigation. The Group owns certain natural gas pipeline facilities that it believes meet the traditional tests FERC has used to establish a pipeline's primary function as "gathering," thus exempting it from the jurisdiction of FERC under the Natural Gas Act.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that the Group produces, as well as the revenues it receives for sales of its natural gas. FERC regulates the transportation of oil and NGLs on interstate pipelines under the provisions of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate transportation of oil, NGLs and other products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

Natural gas, NGLs and crude oil prices are currently unregulated, but Congress historically has been active in the area of natural gas, NGLs and crude oil regulation.

Health and Safety Laws

The Group's operations are subject to regulation under the federal Occupational Safety and Health Act ("**OSHA**") and comparable state laws in some states, all of which regulate health and safety of employees at the Group's operations. Additionally, OSHA's hazardous communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorisation Act and comparable state laws require that information be maintained about hazardous materials used or produced by the Group's operations and that this information be provided to employees, state and local governments and the public.

Climate Change Laws and Regulations

Climate change continues to be a legislative and regulatory focus. There are a number of proposed and recently-enacted laws and regulations at the international, federal, state, regional and local level that seek to limit greenhouse gas emissions, and such laws and regulations that necessitate the installation of new equipment or the purchase of emission allowances. For example, the Inflation Reduction Act, which was signed into law in August 2022, includes a "methane fee" that became effective in 2024. In addition, the U.S. EPA has imposed more stringent methane emissions standards for new and existing gas and oil operations. These laws and regulations could also impact the Group's customers, including the electric generation industry, making alternative sources of energy more competitive and thereby decreasing demand for the natural gas and oil the Group produces. Additional regulation could also lead to permitting delays and additional monitoring and administrative requirements, in turn impacting electricity generating operations.

At the international level, President Biden has recommended the United States to the UN-sponsored "Paris Agreement," for nations to limit their greenhouse gas emissions through non-binding, individually-determined reduction goals every five years after 2020. In April 2021, President Biden announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered in Glasgow at the 26th Conference of the Parties to the UN Framework Convention on Climate Change, during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non- carbon dioxide greenhouse gases. In a related gesture, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane emissions at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. Such commitments were re-affirmed at the 27th Conference of the Parties in Sharm El Sheikh. The Trump Administration may diverge from the prior Biden Administration's positions and could withdraw from or otherwise roll back certain GHG commitments. While it is not possible at this time to predict how any such actions may impact the Group's business, such actions could prompt more activity from federal, state, and local legislative bodies and administrative agencies to pass stricter GHG laws, regulations, and other binding commitments.

17. Dividend policy

The Company has consistently declared dividends on the ordinary shares since its listing on the AIM Market of the LSE in 2017. The Board currently expects to declare a dividend of $0.29 per share each quarter which equates to $1.16 per year. This quarterly dividend payment, on an annualised basis, currently delivers a yield in the top quartile of the FTSE 250 share index and the top decile among the Russell 2000 Index. While the Board cannot provide assurance that the Company will be able to pay cash dividends on the Ordinary Shares in future periods, subject to certain restrictions, including those related to English law, and the terms of the Group's Credit Facility, for the financial year ended 31 December 2023, the Company paid a dividend of $3.50 per Ordinary Share and for the nine months ended 30 September 2024, the Company has paid dividends of an aggregate of approximately $69 million.

Under English law, among other things, the Company may only pay dividends if it has sufficient distributable reserves, which are the Company's accumulated realised profits that have not been previously distributed or capitalised less the Company's accumulated realised losses, so far as such losses have not been previously written off in a reduction or reorganisation of capital. In addition, the Company's ability to pay dividends is limited by restrictions under the terms of certain of its credit facilities. For example, the Group's Credit Facility contains a restricted payment covenant that limits the Group's subsidiaries' ability to make certain payments, based on the pro forma effect thereof on certain financial ratios.

The Board has not adopted, and does not currently intend to adopt, a formal written Company shareholder dividend policy and the Directors may revise the Group's dividend strategy from time to time in line with the actual results and financial position of the Group.

Part 2
FINANCIAL INFORMATION RELATING TO THE GROUP

Background

The Group 2023 Financial Statements, as set out in the 2023 Annual Report, and the Group H1 2024 Financial Statements, as set out in the H1 2024 Interim Report, are incorporated by reference into this document. See Part 8 ("*Documents Incorporated by Reference*"). A copy of each of these documents is available for inspection in accordance with paragraph 23 of Part 7 ("*Additional Information*").

The independent auditor's report for the financial year ended 31 December 2023 was unqualified. The independent review report for the six-month period ended 30 June 2024 was unqualified.

The Group 2023 Financial Statements and the Group H1 2024 Financial Statements are presented in US dollars and have been prepared in accordance with UK-adopted International Accounting Standards and the requirements of the Companies Act 2006 as applicable to companies reporting under those standards. This financial information relating to the Group has been extracted without material adjustment from the Group 2023 Financial Statements and the Group H1 2024 Financial Statements as included in the 2023 Annual Report and the H1 2024 Interim Report respectively.

Cross reference list

Investors are referred to Part 8 ("*Documents Incorporated by Reference*") for specific items of information which have been incorporated by reference into this document.

Part 3
HISTORICAL FINANCIAL INFORMATION RELATING TO THE MAVERICK GROUP

SECTION A

MAVERICK NATURAL RESOURCES, LLC AND SUBSIDIARIES

Consolidated Financial Statements

December 31, 2023 and 2022

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Balance Sheets
December 31, 2023 and 2022

	December 31,	
	2023	**2022**
	(in thousands of dollars)	
Assets		
Current assets		
Cash	$ 53,263	$ 10
Restricted cash – current	31,936	3,232
Accounts receivable, net	140,260	197,232
Derivative instruments	46,503	1,051
Inventory	2,209	1,806
Prepaid expenses and other current assets	7,089	8,244
Total current assets	281,260	211,571
Property, plant and equipment		
Oil and natural gas properties	2,674,820	2,426,672
Other property, plant and equipment	110,888	77,230
Property, plant and equipment	2,785,708	2,503,902
Accumulated depletion, depreciation, and impairment	(1,097,788)	(876,451)
Property, plant and equipment, net	1,687,920	1,627,451
Other long-term assets		
Restricted cash	—	13,564
Derivative instruments	48,018	4,354
Operating lease right-of-use assets	12,362	5,136
Other long-term assets	35,577	38,449
Total assets	$ 2,065,137	$ 1,900,525
Liabilities and Equity		
Current liabilities		
Accounts payable and accrued expenses	$ 272,637	$ 340,393
Current portion of long-term debt	113,773	717
Derivative instruments	98	99,302
Current portion of asset retirement obligation	7,282	5,060
Operating lease obligations – current	841	3,606
Total current liabilities	394,631	449,078
Long-term debt	697,405	411,920
Derivative instruments	3,994	8,330
Asset retirement obligation	242,391	248,221
Operating lease obligations – noncurrent	25,316	2,112
Other long-term liabilities	29,501	25,715
Total liabilities	1,393,238	1,145,376
Members' equity	671,899	755,148
Total liabilities and equity	$ 2,065,137	$ 1,900,525

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Operations
Years Ended December 31, 2023 and 2022

	Twelve Months Ended December 31,	
	2023	**2022**
	(in thousands of dollars)	
Revenues and other income items		
Oil revenues	$ 619,524	$ 720,668
Natural gas revenues	161,054	413,234
NGL revenues	113,320	202,239
Oil, natural gas and NGL revenues	893,898	1,336,141
Gain (loss) on commodity derivative instruments	145,934	(262,083)
Other revenues, net	83,492	106,945
Total revenues and other income items	1,123,324	1,181,003
Operating costs and expenses		
Operating costs	488,261	576,482
Depletion, depreciation and amortization	166,488	148,659
Impairment of oil and natural gas properties	66,785	118,839
General and administrative expenses	83,318	61,326
Restructuring costs	1,631	283
(Gain) loss on sale of assets	(1,090)	(1,142)
Total operating costs and expenses	805,393	904,447
Operating income	317,931	276,556
Interest expense	62,176	25,109
Other income, net	(1,130)	(230)
Total other expense (income)	61,046	24,879
Income before taxes	256,885	251,677
Income tax expense (benefit)	604	1,070
Net income	$ 256,281	$ 250,607

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity
Years Ended December 31, 2023 and 2022

	Outstanding Common Units	Common Equity	Total Members' Equity
		(in thousands of dollars)	
Balances, December 31, 2021	**2,894**	**$ 624,567**	**$ 624,567**
Unit-based compensation	—	256	256
Units issued under unit-based compensation awards, net of tax withholdings	2	(57)	(57)
Net income	—	250,607	250,607
Redemption of units	—	(21)	(21)
Distributions	—	(120,000)	(120,000)
Other	—	(204)	(204)
Balances, December 30, 2022	**2,896**	**$ 755,148**	**$ 755,148**
Unit-based compensation	—	327	327
Units issued under unit-based compensation awards, net of tax withholdings	2	1,987	1,987
Net income	—	256,281	256,281
Redemption of units	(1)	(1,548)	(1,548)
Distributions	—	(340,000)	(340,000)
Other	—	(296)	(296)
Balances, December 31, 2023	**2,897**	**$ 671,899**	**$ 671,899**

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Cash Flows
Years Ended December 31, 2023 and 2022

	Twelve Months Ended December 31,	
	2023	2022
	(in thousands of dollars)	
Cash flows from operating activities		
Net income	$ 256,281	$ 250,607
Adjustments to reconcile cash flow from operating activities:		
Depletion, depreciation and amortization	166,488	148,659
Impairment of oil and natural gas properties	66,785	118,839
(Gain) loss on derivative instruments	(145,934)	262,083
Derivative instrument settlement payments	(46,722)	(370,798)
Deferred income taxes	(13)	(41)
Loss (gain) on sale of assets	(1,090)	(1,142)
Restructuring costs, net of payments	124	124
Write-off of debt issuance costs	5,649	2,374
Other	5,594	14,846
Changes in assets and liabilities:		—
Accounts receivables and other assets	48,621	(73,512)
Inventory	(403)	(249)
Accounts payable and accrued expenses	(47,119)	78,153
Net cash provided by (used in) operating expenses	308,261	429,943
Cash flows from investing activities		
Capital acquisitions, net	(17,968)	(544,065)
Capital expenditures	(286,420)	(241,633)
Proceeds from sale of assets	15,514	10,082
Net cash provided by (used in) investing activities	(288,874)	(775,616)
Cash flows from financial activities		
Distributions to common unitholders	(340,000)	(120,000)
Credit facility borrowings	355,000	753,000
Repayments of credit facility	(575,000)	(343,000)
Issuance of term debt	630,000	(22,250)
Long-term debt issuance costs	(18,488)	—
Redemption of common units	(1,548)	(507)
Principal payments on finance lease obligations	(958)	(375)
Other	—	(204)
Net cash (used in) provided by financing activities	49,006	266,664
(Decrease) increase in cash and restricted cash	68,393	(79,009)
Cash and restricted cash – beginning of period	16,806	95,815
Cash and restricted cash – end of period	$ 85,199	$ 16,806

1. Nature of Operations

Maverick Natural Resources, LLC ("**MNR**" or "**Parent**") and its subsidiaries, including Maverick Asset Holdings LLC ("**MAH**"), newly formed Maverick ABS Holdco, LLC ("**ABS Holdco**"), and Maverick Services, LLC ("**MAV Services**"), (collectively, "**Maverick**," "**we**" or the "**Company**") is a Delaware limited liability company formed on March 22, 2018. We are a Houston, Texas-based oil and natural gas company focused on the development and production of long-lived oil and natural gas reserves throughout the United States. Our primary operations are in seven regions in the United States: East Texas, Mid-Continent (Western Oklahoma and Eastern New Mexico); Permian (West Texas); Rockies (Wyoming); Southeast (Southwest Florida, Florida Panhandle and Alabama); and Western Anadarko (Texas Panhandle and Southwestern Oklahoma).

On October 26, 2023, the Parent, through its consolidated subsidiaries, raised $640 million through an asset-backed securitization financing transaction. Several new subsidiaries were created including MNR ABS Holdings I, LLC ("**ABS Holdings**") and MNR ABS Issuer I, LLC ("**ABS Issuer**"). See Note 4 – Acquisitions and Divestitures – Transactions Between Entities Under Common Control and Note 10 – Debt for further discussion.

During 2022, the Company acquired certain producing properties in the Permian Basin and in the Western Anadarko Basin from two separate oil and gas companies in separate transactions. See Note 4 for further discussion.

During 2022, the Company divested properties in and the Midwest region. Certain Midwest divestitures resulted in the deconsolidation of entities. See Note 4 – Acquisitions and Divestitures for further discussion.

The Company operates its properties through its primary operating subsidiaries: Breitburn Operating, L.P. ("**BOLP**"), Unbridled Resources, LLC ("**Unbridled**"), and Maverick Permian, LLC.

In addition to our operating companies, the Company's subsidiaries include: (i) Wheeler Midstream, LLC, an oil terminal located in Wheeler County, TX, which purchases oil from both properties operated by Unbridled, a wholly owned entity, and third-party operated properties, (ii) MidPoint Midstream, LLC, a gas gathering operation located in Wheeler and Hemphill Counties, Texas and Roger Mills and Beckham Counties, Oklahoma, which gathers and compresses natural gas produced from Unbridled and third party operated properties, and (iii) Bluebonnet Resources, LLC, which acquired unproved acreage for development purposes.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States ("**GAAP**"). Our consolidated financial statements include Maverick and our wholly owned or majority-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Recently Adopted Accounting Standards

In June 2016, the Financial Accounting Standards Board ("**FASB**") issued Accounting Standards Update ("**ASU**") No. 2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("**ASU 2016-13**"), which changes the impairment model for most financial assets. The ASU introduces a new credit loss methodology, Current Expected Credit Losses (CECL), which requires earlier recognition of credit losses, while also providing additional transparency about credit risk. Since its original issuance in 2016, the FASB has issued several updates to the original ASU. The CECL framework utilizes a lifetime "expected credit loss" measurement objective for the recognition of credit losses for loans, held-to-maturity securities, and other receivables at the time the financial asset is originated or acquired. The expected credit losses are adjusted each period for changes in expected lifetime credit losses. The methodology replaces the multiple existing impairment methods, which generally require that a loss be incurred before it is recognized.

On January 1, 2023, the Company adopted the guidance applying the modified retrospective basis approach. The adoption of this standard did not have a material impact on the Company's consolidated financial statements as of the adoption date, January 1, 2023.

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("**ASU 2020-04**"), which provided optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that referenced LIBOR ("**London Inter-Bank Offered Rate**") or another rate. ASU 2020-04 was in effect through December 31, 2022. In January 2021, the FASB issued ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope ("**ASU 2021-01**"), to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848" ("**ASU 2022-06**"), which defers the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. As of December 31, 2023, the Company's borrowings under its Credit Facility bear interest at an ABR or SOFR basis plus an applicable margin and the ABS loans have a fixed interest rate. At this time, the Company does not plan to enter into additional contracts using LIBOR as a reference rate. For additional information, see Note 10 – Debt.

In October 2021, the FASB issued ASU 2021-07, "Compensation – Stock Compensation (Topic 718): Determining the Current Price of an Underlying Share for Equity-Classified Share-Based Awards" as a practical expedient to allow a nonpublic entity to determine the current price input of equity-classified share-based awards issued to both employees and nonemployees using the reasonable application of a reasonable valuation method. The practical expedient describes the characteristics of the reasonable application of a reasonable valuation method as the same characteristics used in the regulations of the U.S. Department of Treasury for income tax purposes (the "**Treasury Regulations**"). Consequently, a reasonable valuation performed in accordance with the Treasury Regulations is an example of a way to achieve the practical expedient. This accounting standard had no effect on the Company and the company continues to use a reasonable valuation method for its equity classified awards.

Significant Recent Accounting Standards Issued Not Yet Adopted

In March 2023, the FASB issued an ASU to amend certain provisions of ASC 842 that apply to arrangements between related parties under common control. The ASU amends the accounting for the amortization period of leasehold improvements in common-control leases for all entities and requires certain disclosures when the lease term is shorter than the useful life of the asset. This ASU is effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. Early adoption is permitted. We do not expect the application of this ASU to have a material impact on our consolidated financial statements or disclosures.

Use of Estimates

The preparation of financial statements and related footnotes in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

Our significant estimates include oil and natural gas reserves; cash flow estimates used in impairment testing of oil and natural gas properties and midstream assets; depreciation, depletion, amortization ("**DD&A**") and accretion; asset retirement obligations ("**ARO**"); accrued revenue and related receivables; operating expenses and accrued liabilities; valuation of liability-classified incentive awards; mark-to-market hedge valuations; and unit-based compensation. We believe our estimates are reasonable, and actual results could differ significantly from these estimates.

Cash and Restricted Cash

Our cash consists of cash in the bank. Current restricted cash represents funds held in escrow that will be used to settle certain general unsecured claims related to the 2018 bankruptcy and cash held in a liquidity reserve account and collection account maintained in connection with the ABS Financing Transaction. At December 31, 2023, the amounts in Restricted Cash consisted of $3.2 million, $23.6 million and $5.1 million for the escrow, liquidity reserve and collection accounts, respectively. At December 31, 2022, the escrow account had a balance of $3.2 million. The liquidity reserve and the collection account did not have a balance at December 31, 2022. Long-term restricted cash represents funds held for future development costs and abandonment obligations at the Jay field. See Note 8 – Other Long-Term Assets for further discussion.

Revenue Recognition and Natural Gas Balancing

We recognize revenues from the sale of oil, natural gas and natural gas liquid ("**NGL**") when control of the oil, natural gas and NGL production has transferred to the customer, the transaction price has been determined and collectability is reasonably assured and evidenced by a contract. Performance obligations under our contracts with customers are typically satisfied when oil, natural gas and NGL are transferred through delivery at the inlet of pipeline or processing plant, onloading to the delivery truck or barge.

Oil terminal revenues are recognized when delivery to the purchaser has occurred, title has transferred, and the associated receivable is recoverable.

We generate gathering revenues by providing gathering and compression services to third parties. We recognize revenue for these arrangements over time based on a per unit rate applied to volumes that travel through the gathering system. In addition, we retain any drip liquids collected on our gathering systems. The value of these drip liquids is recognized as part of gathering revenue in the month the underlying gathering service is provided based upon the price realized for sale of drip condensate to third party customers which represents a market price.

Natural gas production imbalances represent the fair value of amounts payable or receivable for natural gas production imbalances, and revenues are recognized based on our share of volumes sold, regardless of whether we have taken our proportional share of volume produced. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2023 and 2022, our natural gas production imbalance asset of $3.1 million and $3.0 million, respectively, was included in other long-term assets and natural gas production imbalance liability of $21.8 million and $23.9 million, respectively, was included in other long-term liabilities on our consolidated balance sheets.

Inventory

Inventory represents our share of crude oil produced from our Florida and Texas operations that is held in storage tanks and unsold at the end of the period. Inventory is reported as current assets in our consolidated balance sheets and carried at the lower of cost or market. We assess the carrying value of our inventory periodically to determine any adjustments necessary to reduce the carrying value to net realizable value. Uncertainties that may impact our assessment include: the applicable quality and location differentials and changes in the timing of a sale. We did not recognize any write-downs during the periods presented.

Property, Plant and Equipment

Proved Oil and Natural Gas Properties

We account for oil and natural gas exploration and development activities using the successful efforts method. Under this method, all property acquisition and development costs are capitalized when incurred and depleted on a unit-of-production basis over total proved reserves and proved developed reserves, respectively. Proved leasehold costs associated with proved reserves are depleted based on total proved reserves, which include proved undeveloped reserves.

Costs of retired, sold or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds to accumulated DD&A unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently in the consolidated statements of operations.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties include lease acquisition costs which are costs incurred to acquire unproved leases. Lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated lease acquisition costs. Lease acquisition costs that are expensed are recorded as “impairment of oil and natural gas properties” in our consolidated statements of operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Natural Gas Properties

We evaluate proved oil and natural gas properties for impairment whenever facts or circumstances indicate that the carrying values of such properties may not be recoverable. We perform impairment assessments by grouping assets at the lowest level for which there are identifiable cash flows. Impairment is indicated when a triggering event occurs and/or the sum of the estimated future net cash flows of an evaluated asset group is less than the asset group’s carrying value. Triggering events may include potential disposition of assets and declines in oil, natural gas and NGL prices. If impairment is indicated, we estimate fair value using a discounted cash flow approach. The factors used to determine fair value are subject to management’s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with risk and current market conditions associated with realizing the expected cash flows projected.

We evaluate unproved oil and natural gas properties periodically for impairment on a geographic basis based on remaining lease terms, drilling results or future plans to develop acreage. These factors may be affected by economic factors including future oil and natural gas prices and projected capital costs.

We evaluate the recovery of our other property, plant and equipment whenever events or circumstances indicate a decline in the recoverability of the respective carrying values may have occurred. We compare the net carrying value of the asset group to the undiscounted net cash flows projected. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount to fair value.

Impairment expense for proved and unproved properties is reported as “impairment of oil and natural gas properties” in the consolidated statements of operations. Impairment expense for other property, plant and equipment is reported as “impairment of long-lived assets” in the consolidated statements of operations.

Other Property, Plant and Equipment

Other property, plant and equipment include buildings, field equipment, compressors, furniture, leasehold improvements, computer hardware and software. We record other property, plant and equipment at cost and depreciate the assets on the straight-line method over the estimated lives of the individual assets.

We assign the useful lives of our property, plant and equipment based upon our internal estimates that are reviewed by management periodically. We use estimated lives of 20 years for our buildings, two to seven years for field equipment, furniture and computer hardware and software, and the remaining lease term for leasehold improvements. At the time of sale or disposal, the costs and accumulated DD&A of the sold or disposed assets are removed from our consolidated balance sheets with any gain or loss realized in our consolidated statements of operations.

Midstream Assets

Midstream assets consist primarily of natural gas gathering and pipelines, as well as an oil terminal. Renewals and betterments, which substantially extend the useful lives of the assets, are capitalized and reported as other property, plant and equipment in our consolidated balance sheets. Maintenance and repairs are expensed when incurred. These assets are depreciated on the straight-line method over 3 to 30 years. We consider estimated future dismantlement, restoration and abandonment costs in our calculation of straight-line DD&A for our natural gas gathering, processing facilities and pipelines.

Leases

At inception, contracts are assessed for the presence of a lease according to the criteria prescribed by Accounting Standards Codification (“**ASC**”) Topic 842, “Leases” (“**ASC 842**”). If a lease is present, further criteria is assessed to determine if the lease should be classified as an operating or finance lease. Operating leases are presented on the consolidated balance sheet as Operating lease right-of-use assets with the corresponding lease liabilities presented as Operating lease obligations – current and Operating lease obligations noncurrent. Finance lease assets are presented on the consolidated balance sheet as Other property, plant and equipment with the corresponding liabilities presented in Current portion of long-term debt and Long-term debt.

Generally, lease liabilities are recognized at commencement and based on the present value of the future minimum lease payments to be made over the lease term. Lease assets are then recognized based on the value of the lease liabilities. For leases where the implicit lease rates are not determinable, the minimum lease payments are discounted using the Company's collateralized incremental borrowing rates.

Operating leases are expensed according to their nature and recognized in Operating expenses or General and administrative expenses. Finance leases are depreciated and amortized with the relevant expenses recognized in Depreciation, Depletion and Amortization and Interest Expense on the consolidated statement of operations. See Note 6 – Leases for further discussion.

Revenue and Production Taxes Payable

We calculate and pay taxes and royalties on crude oil and natural gas in accordance with particular contractual provisions of the leases, license or concession agreements and the laws and regulations applicable to those agreements.

Asset Retirement Obligations

We recognize estimated liabilities for future costs associated with the abandonment of our oil and natural gas properties, gas gathering, processing facilities and pipelines. We record a liability for the fair value of an ARO and a corresponding increase to the carrying value of the related long-lived asset in the period in which wells are drilled or acquired. See Note 11 – Asset Retirement Obligations for further discussion.

Liability-Classified Awards

We classify certain awards that will be settled in cash as liability awards in our balance sheet in accounts payable and accrued expenses. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense and operating costs over the vesting period of the award. The Company's liability-classified awards include a performance condition based on preceding Implied Equity Value (as defined in Note 14 – Compensation). See Note 5 – Financial Instruments and Fair Value Measurements for further discussion.

Unit-Based Compensation

Unit-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards is recognized on a straight-line basis over the requisite service period. See Note 14 – Compensation for further discussion.

Environmental Liabilities

We are subject to federal, state and local environmental laws and regulations. These laws regulate the release, disposal or discharge of materials into the environment or otherwise relate to environmental protection. These laws and regulations may require that we remove or mitigate the environmental effect of the discharge, disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. We expense expenditures related to an existing condition caused by past operations that have no future economic benefit. We record liabilities for noncapital expenditures when environmental assessments or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability is fixed or determinable. We did not have environmental liabilities at December 31, 2023 and December 31, 2022, respectively.

Business Combinations and Asset Acquisitions

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition-date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of the proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average costs of capital rate are subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into exchange for such properties.

Any excess of the acquisition price over the estimated fair value of net assets acquired in recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded as a bargain purchase gain in other income, net on our consolidated statements of operations.

In an asset acquisition, transaction costs are capitalized, and any excess or deficit of fair value of net assets in relation to acquisition price is allocated to the acquired assets based on the relative fair value.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine that it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the mostly likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss.

Fair Value of Financial Instruments

Certain of our financial assets and liabilities are measured at fair value. Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Our financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 5 – Financial Instruments and Fair Value Measurements for additional details.

Fair Value of Nonfinancial Assets and Liabilities

We apply fair value accounting guidance to measure our nonfinancial assets and liabilities such as those obtained through property, plant and equipment, AROs and restructuring. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. Under the discounted cash flow method, estimated future cash flows are based on management’s expectations for the future and include estimates of future oil and natural gas production and other applicable sales estimates, operational costs and risk-adjusted discount rate. We may use the present value of estimated future cash inflows and outflows, third-party offers or prices of comparable assets with consideration of the current market conditions to value our nonfinancial assets and liabilities when circumstances dictate fair value determination is necessary.

Concentrations of Credit Risk

We are subject to credit risk resulting from the concentration of our oil, natural gas and NGL receivables with the following major purchasers that accounted for 10% or more of our total oil, natural gas and NGL sales for the periods presented:

	Twelve Months Ended December 31,	
	2023	2022
Purchaser		
Customer A	15%	N/A
Customer B	12%	12%
Customer C	11%	19%

Our financial instruments with credit risk exposure consist principally of cash and cash equivalents, accounts receivable, and derivative instruments. We maintain cash and cash equivalents in deposit accounts at financial institutions that may exceed the federally insured limits. We monitor credit risk exposure by (i) placing our assets and other financial instruments with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include our evaluation of customers' financial condition and monitoring payment history and (iii) netting derivative assets and liabilities where we have legal right of offset with counterparties and diversifying our derivative instrument portfolio.

Risk Management and Derivative Instruments

We have entered into derivative contracts with counterparties to reduce the effect of changes in oil and natural gas prices on a portion of our oil and natural gas production. We do not enter into such contracts for speculative trading purposes. Our commodity derivative instruments are measured at fair value in our consolidated balance sheets as derivative assets or derivative liabilities. We have not designated any derivative instruments as hedges for accounting purposes. Gains and losses from valuation changes in commodity derivatives are reported as (gain) loss on commodity derivative instruments in our consolidated statements of operations. Our cash flows are only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. Cash settlements are reflected as operating activities in our consolidated statements of cash flows. We expense transaction costs related to the modification of derivative instruments as incurred. See Note 5 – Financial Instruments and Fair Value Measurements for further discussion of our derivative instruments.

We have market and credit risk exposure due to commodity derivatives that are concentrated with certain counterparties who are affiliate lenders under the Credit Agreement. We believe the risk of nonperformance by our counterparties is low as we execute our derivative contracts only with credit-worthy financial institutions and we have no past-due receivables from our derivative counterparties. As of December 31, 2023, our largest derivative counterparties were Citizens Bank N.A., Key Bank National Association, J. ARON & Company, and JP Morgan Chase Bank N.A., which accounted for approximately 58.22%, 18.80%, 16.65%, and 6.33%, respectively, of our derivative settlement payable balance of $8.9 million.

Our commodity derivative contracts are documented with industry standard contracts known as Schedule to the Master Agreement and International Swaps and Derivatives Association, Inc. Master Agreement ("**ISDA**"). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. We are not required to provide any credit support to our counterparties other than cross collateralization with the oil and natural gas properties securing the Credit Agreement. We have certain limitations under the Credit Agreement, including a provision that limits the total amount of our production that may be hedged to certain percentages of current and forecasted production. As of December 31, 2023, we were in compliance with these limitations. See Note 5 – Financial Instruments and Fair Value Measurements and Note 10 – Debt for additional information.

Debt Issuance Costs

Debt issuance costs related to our Credit Facility and ABS Notes are amortized over the life of the related debt using the effective interest rate method and unamortized debt issuance costs are netted against the outstanding balance of debt obligations on our consolidated balance sheets. Any unamortized costs associated with retired debt are written off and included in the determination of gain or loss on extinguishment of debt.

Revenues

Sales of oil, natural gas and NGL are recognized at the point when control of the commodity is transferred to the customer and collectability is reasonably assured. Most of our contracts' pricing provisions are tied to a commodity market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with the other available oil, natural gas and NGL suppliers.

Oil Sales

Under our crude purchase and marketing contracts, we generally sell oil production at the wellhead and collect an agreed-upon index price, net of pricing differentials. We recognize revenue when control transfers to the purchaser at the wellhead or delivery point for onloading to delivery truck or barge at the net price received.

Natural Gas and NGL Sales

Under our natural gas gathering, processing and purchase contracts, we deliver unprocessed natural gas to processing plants at the wellhead or the inlet of the processing plant's system. The midstream entity then gathers and processes the natural gas to produce residue gas and NGLs generated from processing. In the majority of cases, the midstream entity remits payment to us for NGLs based on index-based pricing or weighted average sales proceeds less deductions which may include gathering, processing and transportation fees, while the residue gas is redelivered to us at the tailgate of the midstream entity's processing plant for marketing under separate contracts. We sell residue gas at the delivery point specified in the separate contract and collect an agreed-upon index price, net of pricing differentials. Transportation, gathering and processing costs incurred after control transfers to the purchaser are recognized as reductions to revenues rather than as operating costs.

Oil Terminal Sales

Under our oil terminal sales contracts, we sell oil at the delivery point specified in the contract and collect an agreed-upon index price, net of pricing differentials. Control as defined under ASC 606, "Revenue from Contracts with Customers" ("**ASC 606**") passes at the delivery point. The delivery point is the point at which the oil passes the last permanent delivery flange or meter connecting our facility to customer's facility. At the delivery point, the customer takes physical custody, title and risk of loss of the product and we have a right to receive payment for the sale. We recognize revenue at the net price received when control transfers to the customer. Oil terminal sales are reported in other revenues, net on our consolidated statements of operations.

Gathering Revenue

We generate gathering revenues by providing gathering and compression services to third parties, which are reported in other revenues on our consolidated statement of operations. We recognize revenue for these arrangements over time based on a per unit rate applied to volumes that travel through the gathering system. In addition, we retain any drip liquids collected on our gathering systems. The value of these drip liquids is recognized as part of gathering revenue in the month the underlying gathering service is provided based upon the price realized for sale of drip condensate to third party customers which represents a market price.

Purchased Condensate Sales

The Company's purchased oil and natural gas sales are derived from the sale of oil and natural gas purchased from a third party and reported in other revenues, net on our consolidated statements of operations. Revenues and expenses from these sales and purchases are generally recorded on a gross basis, as the Company acts as a principal in these transactions by assuming control of the purchased oil or natural gas before it is transferred to the customer.

Performance Obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. We record revenue on our oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the production is delivered.

We have elected practical expedients, pursuant to ASC 606, to exclude from the presentation of remaining performance obligations: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue under the right to invoice practical expedient.

Contract Balances

We invoice our customers when we have satisfied our performance obligations, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to third party purchasers. Accounts receivable is held at cost. At each reporting date, the Company assesses the expected lifetime credit losses on initial recognition of accounts receivable. At December 31, 2023, the credit loss allowance on accounts receivable from joint interest owners was $5.8 million, and the Company recorded $0.6 million of credit losses during 2023. At December 31, 2023, no credit loss allowance existed on revenue accounts receivable, and no credit losses were recorded during the period.

3. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Twelve Months Ended December 31,	
	2023	2022
	(in thousands of dollars)	
Cash payments		
Interest	$ 34,799	$ 12,927
Noncash investing activities		
(Increase) decrease in accrued capital expenditures	$ (10,809)	$ 34,081
(Increase) in asset retirement obligations	(11,202)	(3,804)
Increase in assets under operating leases	(10,928)	(3,032)
Decrease in liabilities for asset divestitures	(1,545)	(1,015)
Asset retirement obligations assumed	—	22,917
Noncash financing activities		
Increase in assets under finance leases	(1,876)	(2,982)
Reconciliation of cash, cash equivalents, and restricted cash reported in the consolidated balance sheets		
Cash and cash equivalents	$ 53,263	$ 10
Restricted cash	31,936	16,796
Total cash, cash equivalents, and restricted cash shown in the statement of cash flows	$ 85,199	$ 16,806

4. Acquisitions and Divestitures

Acquisitions

In January 2022, we entered into a definitive agreement to acquire certain producing properties in the Permian Basin from a large independent oil and gas company for a purchase price of $440 million, subject to customary adjustments (the "**Permian Acquisition**"). The acquisition was accounted for as a business combination. Through December 31, 2022, the purchase price allocation was adjusted as shown in the table below. These adjustments have been retrospectively reflected as of the acquisition date. This transaction closed in April 2022 and related transaction costs were $0.4 million.

The following table summarizes the net assets acquired from the Permian Acquisition.

	Permian Acquisition
	(in thousands of dollars)
Net assets purchased	
Oil and gas properties	$ 379,867
Other property, plant, and equipment	7,460
Asset retirement of obligation	(19,486)
Working capital adjustments	1,773
Fair value of net assets	$ 369,614
Consideration	
Purchase price	$ 440,000
Pre-close adjustments	(70,386)
Total consideration and post purchase price adjustments	369,614
Deposit paid in January 2022	(33,000)
Total consideration and post purchase price adjustments, net of deposit paid	$ 336,614

In May 2022, we entered into a definitive agreement to acquire certain producing properties in the Western Anadarko Basin from a large independent oil and gas company for a purchase price of $180 million, subject to customary adjustments (the "**Anadarko Acquisition**"). The acquisition was accounted for as a business combination. Through December 31, 2022, the purchase price allocation was adjusted as shown in the table below. These adjustments have been retrospectively reflected as of the acquisition date. This transaction closed in June 2022.

The following table summarizes the net assets acquired from the Anadarko Acquisition.

	Anadarko Acquisition
	(in thousands of dollars)
Net assets purchased	
Oil and gas properties	$ 170,580
Asset retirement of obligation	(3,430)
Working capital adjustments	(550)
Fair value of net assets	$ 166,600
Consideration	
Purchase price	$ 180,000
Pre-close adjustments	(13,400)
Total consideration and post purchase price adjustments	$ 166,600

Both acquisitions were funded by a fully committed $750 million reserve-based loan provided by a syndicate of banks, see further details in Note 10 – Debt.

During 2023, we acquired approximately 25,000 net acres of unproved acreage in Texas for total consideration of $14.6 million. The acquisition was financed through borrowings under our existing credit facility. The acreage is considered strategic to the Company's long-term growth objectives and is expected to provide significant opportunities for exploration and development. These leases are currently in the early stages of evaluation.

Transactions Between Entities Under Common Control

On October 26, 2023, Unbridled entered into an asset purchase agreement with ABS Issuer (the "**Purchase and Sale Agreement**"). Unbridled agreed to sell and transfer to ABS Issuer certain operated and non-operated oil and natural gas wells and all oil and natural gas leases, subleases and leasehold covering such wells (the "ABS Assets" and such transfer, the "ABS Asset Transfer") for a purchase price of $640 million, of which $630 million was cash and $10 million was a non-cash note payable. In connection with the ABS Asset Transfer, MAH transferred by novation to the ABS Issuer certain hedge agreements ("Assumed Hedges").

In connection with the transaction, ABS Issuer entered into an indenture with UMB Bank, N.A. as indenture trustee (the "**Indenture Trustee**") (the "**Indenture**") to which ABS Issuer issued (a) $640 million aggregate principal amount of Series 2023-1 Notes, consisting of (i) $285 million aggregate principal amount of its 8.121% Series 2023-1 Notes, Class A-1 Notes due December 2038, (ii) $260 million aggregate principal amount of its 8.946% Series 2023-1 Notes, Class A-2 Notes due December 2038 and (iii) $95 million aggregate principal amount of its 12.436% Series 2023-1 Notes, Class B Notes due December 2038 (collectively, the "**ABS Notes**") and (b) pledged the ABS Assets to the Indenture Trustee to secure the ABS Issuer's obligations under the Indenture (the "**ABS Financing Transaction**").

In addition the following events occurred in connection with the transaction: (i) $10 million of the ABS Notes were issued to Maverick, (ii) a holdback of $5.4 million related to consents not received at the date of the transaction which is reflected as restricted cash, (iii) a Liquidity Reserve Account was established for $23.6 million and is reflected as restricted cash, (iv) $260 million was an equity distribution and (v) repaid $300 million for the Credit Facility held by MAH.

We incurred hedge novation fees of $4.6 million in conjunction with the ABS Financing Transaction which were expensed as incurred in general and administrative expenses in our consolidated statement of operations. We incurred $12.7 million of costs including legal fees and administrative fees in connection with the ABS Financing Transaction which were capitalized as deferred financing costs and recorded as an offset to the carrying value of the ABS Notes. See Note 10 – Debt for more information regarding the ABS Notes.

Divestitures

In March 2023, we entered into an agreement with a third party to divest certain interests in oil and natural gas properties, rights and related assets in Western Anadarko Basin for a purchase price of $10.0 million. This sale was accounted for as a normal retirement under the provisions of paragraph ASC 932-360-40-3 with no gain or loss recorded on the sale for the year ended December 31, 2023.

In May 2023, we entered into an agreement with a third party to divest certain properties in west Texas for a purchase price of $4.5 million. We recognized a $0.3 million gain on the sale for the year ended December 31, 2023.

In November 2023, we entered into an agreement with a third party to divest certain interests in oil and natural gas properties, rights and related assets in Wyoming for a purchase price of $0. We recognized a $0.1 million gain on the sale for the year ended December 31, 2023.

In connection with other divestitures of non-core oil and natural gas properties, we recognized gains of $1.1 million in "gain (loss) on sale of assets" on our consolidated statements of operations for the year ended December 31, 2023.

In June 2022, we entered into an agreement with a third party to divest certain interests in oil and natural gas properties, rights and related assets in areas located in Michigan for a purchase price total of $6.0 million. As of June 30, 2022, we classified these as held for sale and we recognized an impairment charge on the properties of $12.0 million for the year-ended December 31, 2022. The transaction closed in August 2022, and we incurred a gain on this sale of $3.3 million for the year ended December 31, 2022.

In January 2022, we divested the Beaver Creek Interests and deconsolidated Beaver Creek, L.L.C. We incurred a loss $1.0 million in connection with this divestiture for the year ended December 31, 2022.

In connection with other divestitures, we recognized gains of $1.2 million in "gain (loss) on sale of assets" on our consolidated statements of operations for the year ended December 31, 2022.

5. Financial Instruments and Fair Value Measurements

Commodity Activities

At December 31, 2023, our commodity derivatives consisted of fixed price swaps and two-way costless collars. Our fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor). The two-way collars are a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling). For both swaps and collars, all transactions are settled in cash for the net difference between settlement and contract prices, multiplied by the hedged contract volumes, for the settlement period.

In October 2023, MAH novated to ABS Issuer certain derivative contracts underlying certain derivative instruments in connection with the ABS Financing Transaction. These derivative contracts consisted of fixed-price oil, natural gas and NGL swaps and collars. As a party to these contracts, ABS Issuer received payments directly from the counterparty or paid any amounts owed directly to the counterparty. Settlement of the novated commodity derivative contracts continued through the date the commodity derivatives instruments were unwound. Costs associated with the novation of $4.6 million were expensed as incurred in general and administrative expenses.

Our commodity derivative contracts settle monthly based on the differential between the contract price and the average NYMEX West Texas Intermediate index price ("**NYMEX WTI**") (oil), average NYMEX Henry Hub index price ("**NYMEX HH**") (natural gas) and Mont Belvieu Oil Price Information Service ("**OPIS**") (NGLs). The following table presents derivative positions for the periods indicated as of December 31, 2023:

	2024	2025	2026	2027	2028	2029	2030
Oil Positions							
Fixed Price Swaps – NYMEX WTI							
Volume (Bbl/d)	11,047	12,226	10,873	3,688	3,366	—	—
Average Price ($/Bbl)	$ 72.10	$ 71.85	$ 68.45	$ 65.95	$ 62.21	$ —	$ —
Fixed Price Swaps – NYMEX BRENT							
Volume (Bbl/d)	—	—	—	—	—	—	—
Average Price ($/Bbl)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Costless Collar – NYMEX WTI							
Volume (Bbl/d)	4,307	—	—	—	—	—	—
Average Put Price ($/Bbl)	$ 63.71	$ —	$ —	$ —	$ —	$ —	$ —
Average Call Price ($/Bbl)	$ 88.96	$ —	$ —	$ —	$ —	$ —	$ —
Total							
Volume (Bbl/d)	15,354	12,226	10,873	3,688	3,366	—	—
Average Price ($/Bbl)	$ 73.29	$ 71.85	$ 68.45	$ 65.95	$ 62.21	$ —	$ —
Gas Positions							
Fixed Price Swaps – Henry Hub							
Volume (MMBtu/d)	87,361	120,838	99,514	69,070	61,056	50,962	47,714
Average Price ($/MMBTu)	$ 3.42	$ 3.90	$ 3.89	$ 3.76	$ 3.63	$ 3.41	$ 3.27
Costless Collar – Henry Hub							
Volume (Bbl/d)	48,663	—	10,000	—	—	—	—
Average Put Price ($/Bbl)	$ 3.03	$ —	$ 3.50	$ —	$ —	$ —	$ —
Average Call Price ($/Bbl)	$ 7.35	$ —	$ 5.15	$ —	$ —	$ —	$ —
Total							
Volume (MMBtu/d)	136,023	120,838	109,514	69,070	61,056	50,962	47,714
Average Price ($/MMBTu)	$ 4.05	$ 3.90	$ 3.89	$ 3.76	$ 3.63	$ 3.41	$ 3.27
NGL Positions							
Fixed Price Swaps							
Volume (Bbl/d)	11,264	9,011	6,427	—	—	—	—
Average Price ($/Bbl)	$ 0.96	$ 0.88	$ 0.83	$ —	$ —	$ —	$ —
Total							
Volume (Bbl/d)	11,264	9,011	6,427	—	—	—	—
Average Price ($/Bbl)	$ 0.96	$ 0.88	$ 0.83	$ —	$ —	$ —	$ —
Fixed Gas Basis Swap							
Volume (Bbl/d)	97,148	84,068	77,423	—	—	—	—
Average Price ($/MMBTu)	$ (0.17)	$ (0.26)	$ (0.22)	$ —	$ —	$ —	$ —

Balance Sheet Presentation

The following table summarizes the fair value of the derivatives outstanding on a gross and net basis:

	December 31, 2023				
	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Commodity Derivatives Netting[a]	Total Financial Instruments
	(Balance sheet location, thousands of dollars)				
Assets					
Current assets – derivative instruments	$ 7,539	$ 39,124	$ 18,958	$ (19,118)	$ 46,503
Other long-term assets – derivative instruments	30,451	39,797	23,686	(45,917)	48,018
Total assets	37,990	78,921	42,645	(65,035)	94,521
Liabilities					
Current liabilities – derivative instruments	(2,897)	(1,931)	(14,388)	19,118	(98)
Long-term liabilities – derivative instruments	(24)	(29,261)	(20,625)	45,917	(3,994)
Total liabilities	(2,921)	(31,193)	(35,013)	65,035	(4,092)
Net assets	$ 35,069	$ 47,728	$ 7,632	$ —	$ 90,429

	December 31, 2022				
	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Commodity Derivatives Netting[1]	Total Financial Instruments
	(Balance sheet location, thousands of dollars)				
Assets					
Current assets – derivative instruments	$ 5,411	$ 4,260	$ 3,893	$ (12,513)	$ 1,051
Other long-term assets – derivative instruments	9,478	6,300	3,699	(15,123)	4,354
Total assets	14,890	10,560	7,592	(27,636)	5,405
Liabilities					
Current liabilities – derivative instruments	(38,228)	(44,236)	(29,352)	12,513	(99,302)
Long-term liabilities – derivative instruments	(9,367)	(11,561)	(2,525)	15,123	(8,330)
Total liabilities	(47,594)	(55,797)	(31,877)	27,636	(107,632)
Net assets	$ (32,705)	$ (45,238)	$ (24,285)	$ —	$ (102,227)

Note:

(1) Represents counterparty netting under our ISDA Agreements. See Note 2 – Summary of Significant Accounting Policies. For our derivative contracts, we may enter into master netting, collateral and offset agreements with counterparties. These agreements provide us the ability to offset a counterparty's rights and obligations, request additional collateral when necessary, or liquidate the collateral in the event of counterparty default. We net the fair value of cash collateral paid or received against fair value amounts recognized for net derivative positions executed with the same counterparty under the same master netting or offset agreement.

The following table summarizes the unrealized gains/losses on commodity derivatives, which are included in the (loss) gain on commodity derivative instruments line of the income statement:

	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Total Financial Instruments
	(in thousands of dollars)			
Twelve Months Ended December 31, 2023	$ 67,774	$ 92,966	$ 31,916	$ 192,656
Twelve Months Ended December 31, 2022	29,114	21,198	58,403	108,715

The following table summarizes the realized gains/losses on commodity derivatives, which are included in the "(loss) gain on commodity derivative instruments" line of the income statement:

	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Total Financial Instruments
	(in thousands of dollars)			
Twelve Months Ended December 31, 2023	$ (35,072)	$ 7,646	$ (19,296)	$ (46,722)
Twelve Months Ended December 31, 2022	(124,698)	(175,443)	(70,658)	(370,798)

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We measure certain assets and liabilities at fair value, using the fair value hierarchy noted below. We use valuation techniques that maximize the use of observable inputs and obtain the majority of our inputs from published objective sources or third-party market participants. We incorporate the impact of nonperformance risk, including credit risk, into our fair value measurements. The fair value hierarchy gives the highest priority of Level 1 to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority of Level 3 to unobservable inputs. We categorize our fair value financial instruments based upon the objectivity of the inputs and how observable those inputs are. The three levels of inputs are described further as follows:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date.

Level 2 Inputs other than quoted prices that are included in Level 1. Level 2 includes financial instruments that are actively traded but are valued using models or other valuation methodologies. We consider the over the counter ("**OTC**") commodity derivative contracts in our portfolio to be Level 2.

Level 3 Inputs that are not directly observable for the asset or liability and are significant to the fair value of the asset or liability. Level 3 includes financial instruments that are not actively traded and have little or no observable data for input into industry standard models. We consider our liability-classified long term incentive plan awards and put option liability to be Level 3 liabilities. See Note 13 – Equity and Note 14 – Compensation for additional details.

Our assessment of the significance of an input to its fair value measurement requires judgment and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels.

Commodity Derivative Instruments

Our commodity derivative instruments include oil, natural gas and NGL swaps and collars. The fair value of our commodity derivative instruments is based on upon a third-party preparer's calculation using mark-to-market valuation reports provided by our counterparties for monthly settlement purposes to determine the valuation of our derivative instruments. We do not have access to the specific proprietary valuation models or inputs used by our counterparties or third-party preparer.

We compare the third-party preparer's valuation to counterparty valuation statements and investigate any significant differences. Additionally, we analyze monthly valuation changes in relation to movements in crude oil and natural gas forward price curves. The fair values reflect nonperformance risk inherent in the transaction using current credit default swap values for each counterparty for asset positions and the Company's creditworthiness for liability positions. Accordingly, we recorded an adjustment to the fair value of our net derivative liability of $4.5 million and $2.4 million at December 31, 2023 and December 31, 2022, respectively.

Fair Value – Recurring Measurement Basis

The following table presents our financial assets and liabilities that were accounted for at fair value on a recurring basis on our consolidated balance sheets at December 31, 2023 and 2022 by level within the fair value hierarchy.

	December 31, 2023			
	Level 1	Level 2	Level 3	Level 4
	(in thousands of dollars)			
Assets				
Oil derivative instruments				
Oil swaps	$ —	$ 32,728	$ —	$ 32,728
Oil collars	—	2,341	—	2,341
Natural gas derivative instruments				
Natural gas swaps	—	34,051	—	34,051
Natural gas collars	—	13,677	—	13,677
NGL derivative instruments				
NGL swaps	—	7,632	—	7,632
Net assets	$ —	$ 90,429	$ —	$ 90,429

	December 31, 2022			
	Level 1	Level 2	Level 3	Level 4
	(in thousands of dollars)			
Assets				
Oil derivative instruments				
Oil swaps	$ —	$ (33,992)	$ —	$ (33,992)
Oil collars	—	1,286	—	1,286
Natural gas derivative instruments				
Natural gas swaps	—	(44,085)	—	(44,085)
Natural gas collars	—	(1,153)	—	(1,153)
NGL derivative instruments				
NGL swaps	—	(24,284)	—	(24,284)
Net assets	$ —	$ (102,227)	$ —	$ (102,227)

Fair Value – Nonrecurring Measurement Basis

Acquisitions and impairment of proved and unproved properties and other non-oil and natural gas properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of property as of the measurement date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil and condensate, natural gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

6. Leases

We primarily have lease agreements for office buildings and vehicles. Our leases generally have lease terms of one year to four years, some of which may include options to extend or shorten the term of the lease at the Company's discretion. We determine if an arrangement is a lease at inception. Some of our leases include lease and non-lease components. We have elected the practical expedient to not separate lease and non-lease components and account for both as a single lease component.

Operating lease right-of-use assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at commencement date. For leases where the implicit rate is not determinable, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. For leases including options to extend or terminate the lease, we factor such terms into our determination of the present value of future payments when it is reasonably certain that we will exercise that option. Operating lease expense for minimum lease payments is recognized on a straight-line basis over the lease term. Variable lease payments and short-term lease payments (leases with initial terms less than 12 months) are expensed as incurred.

Operating lease assets and liabilities are included in operating lease right-of-use assets, operating lease liabilities – current, and operating lease liabilities – noncurrent on our consolidated balance sheets. Our finance lease assets and liabilities are included in other property, plant, and equipment, current portion of long-term debt, and long-term debt on our consolidated balance sheets.

	December 31,	
	2023	2022
	(in thousands of dollars)	
Operating leases		
Operating lease right-of-use assets	$ 12,362	$ 5,136
Operating lease obligations – current	841	3,606
Operating lease obligations – noncurrent	25,316	2,112
Finance leases		
Other property, plant, and equipment[1]	$ 3,455	$ 3,084
Current portion of long-term debt	1,166	717
Long-term debt	2,389	1,920

Note:

(1) Finance lease assets are recorded net of accumulated amortization of $1.5 million and $0.4 million at December 31, 2023 and 2022, respectively.

The following table summarizes the components of leases cost for the periods presented:

	Year Ended December 31, 2023	2022
	(in thousands of dollars)	
Operating lease cost	$ 5,206	$ 5,357
Short-term lease cost	18,105	7,406
Finance lease cost		
Amortization of right-of-use assets	1,003	388
Interest on lease liabilities	198	84
Total lease cost	$ 24,513	$ 13,235

The following table summarizes the lease terms and discount rates:

	Year Ended December 31, 2023	2022
	(in thousands of dollars)	
Lease term and discount rate		
Weighted-average term (years)		
Operating leases	10.23	1.80
Finance leases	2.85	3.50
Weighted-average discount rate (percent)		
Operation leases	7.43%	6.20%
Finance leases	5.86%	5.70%

The following table summarizes other lease information for the periods presented:

	Year Ended December 31, 2023	2022
	(in thousands of dollars)	
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flow from operating leases	$ 8,007	$ (4,633)
Operating cash flow from finance leases	(1,003)	(375)
Financing cash flows from finance leases	(198)	(82)

Future minimum lease payments under noncancellable leases as of December 31, 2023 were as follows:

	Operating Leases	Finance Leases
	(in thousands of dollars)	
2024	$ 1,607	$ 1,368
2025	4,097	1,363
2026	3,951	918
2027	3,486	175
2028	3,527	—
Thereafter	22,736	—
Total lease payments	39,404	3,825
Less: Portion representing imputed interest	(13,247)	(270)
Total lease liabilities	26,157	3,555
Less: Current portion of lease liabilities	(841)	(1,166)
Long-term lease liabilities	$ 25,316	$ 2,389

7. Long-Lived Assets and Impairment

Our long-lived assets are comprised of oil and natural gas properties and other property, plant and equipment for the periods presented:

	2023	2022
	(in thousands of dollars)	
Proven oil and natural gas properties[(1)]	$ 2,548,263	$ 2,310,497
Unproved oil and natural gas properties	126,557	116,175
Total oil and natural gas properties	2,674,820	2,426,672
Other property, plant and equipment	110,888	77,230
Less: Accumulated depletion, depreciation and amortization	(1,097,788)	(876,451)
Net property, plant and equipment	$ 1,687,920	$ 1,627,451

Note:

(1) Estimates of future asset retirement costs of $260.4 million and $249.1 million are included in our proved oil and natural gas properties at December 31, 2023 and 2022, respectively.

Costs are excluded from the amortization base until proved reserves are established or impairment is determined.

Long-Lived Assets Impairment

During the year ended December 31, 2023, we recorded impairment losses totaling $66.8 million in proved properties. We incurred $3.5 million and $59.2 million of impairment in the first and second quarters of 2023 due to a significant decrease in commodity prices driven by a decrease in gas futures. We incurred $0.0 million and $4.1 million of impairment in the third and fourth quarters of 2023 due to significant downward revisions in reserves to certain impairment fields, driven by increased costs and decreased production. During the year ended December 31, 2022, we recorded impairment losses totaling $118.8 million in proved properties. We incurred $12 million of impairment in the second quarter of 2022 on divested properties as mentioned in Note 4 – Acquisitions and Divestitures, due to the sales price of the assets sold being lower than the net book value. We incurred $107.0 million of impairment in the fourth quarter of 2022 due to an increase in operating costs caused by supply chain pressures and an inflationary environment as well as changes in capital plans due to 2022 acquisitions.

Additionally, as a result of expiring leases and our periodic assessment of unproved properties, we amortized $0.0 million and $0.1 million of unproved oil and natural gas properties and reported amounts as depletion, depreciation and amortization in our consolidated statement of operations for the periods ended December 31, 2023 and 2022, respectively.

8. Other Long-Term Assets

Other long-term assets consist of the following:

	2023	2022
	(in thousands of dollars)	
Property reclamation	$ 11,910	$ 11,359
Unamortized debt issuance costs	13,206	17,920
Security deposits	1,735	2,904
Other	8,726	6,266
Total other long-term assets	$ 35,577	$ 38,449

Net Profit Interest

We have a net profit interest ("**NPI**") related to the Jay Field. The NPI is held 50% by Maverick and a third party ("**NPI Holder**"). Under the arrangement, the NPI is payable after: (i) funds are withheld, to the extent allowable each month under the arrangement, to pay for the NPI holder's share of future development costs and abandonment obligations, and (ii) we are reimbursed for the NPI holder's share of excess historical production costs. Once the NPI holder's share of the excess historical costs is reimbursed, the NPI will be payable monthly to the extent the NPI for that month exceeds the amount withheld for that month for future development costs and abandonment obligations. The NPI holder's share of excess historical production costs amounted to $11.5 million and $15.4 million at December 31, 2023 and 2022, respectively.

Additionally, we will retain the NPI holder's share of future development costs and abandonment obligations, subject to future production, production costs, and capital spending level, which will be paid using the funds withheld. The NPI holder's share along with our share of the abandonment costs as of December 31, 2023 and 2022 are reflected in asset retirement obligations on the consolidated balance sheets. Under the arrangement, we have the option to deposit into a separate account the funds withheld from the NPI holder for their portion of the future development costs and abandonment obligations. At December 31, 2023 and 2022, the funds totaled $0.0 million and $13.6 million, respectively, and are reflected in long-term restricted cash on our consolidated balance sheets. See additional details regarding the Jay Field NPI in Note 12 – Commitments and Contingencies and Note 16 – Subsequent Events.

Property Reclamation Deposit

As of December 31, 2023 and 2022, we had a property reclamation deposit of $11.9 and $11.4 million, respectively, included in other long-term assets, held in an escrow account as security for future abandonment and remediation obligations for the Jay Field. We are required to maintain the escrow account in effect for three years after all abandonment and remediation obligations have been completed. The funds in the escrow account are not to be returned to us until the later of three years after satisfaction of all abandonment obligations or December 31, 2026. At certain dates subsequent to closing, we have the right to request a refund of a portion or all of the property reclamation deposit. The seller has the sole discretion to grant our refund request. In addition to the cash deposit, we are required to provide letters of credit. At December 31, 2023 and 2022, we had $21.0 million in letters of credit related to the property reclamation deposit.

9. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following:

	2023	2022
	(in thousands of dollars)	
Accounts payable	$ 112,218	$ 175,804
Revenue and royalties payable	93,315	102,899
Wages and salaries payable	21,008	13,134
Accrued interest payable	12,100	6,071
Production and property taxes payable	22,217	26,808
Hedge settlement payables	8,911	11,331
Other current liabilities	2,868	4,346
Total accounts payable and accrued expenses	$ 272,637	$ 340,393

10. Debt

Our debt was comprised of the following:

	2023	2022
	(in thousands of dollars)	
Credit Facility	$ 190,000	$ 410,000
ABS Notes	640,000	—
Finance Lease Obligations	3,555	2,637
Debt issuance costs	(12,377)	—
Notes held by ABS parent	(10,000)	—
Total debt	811,178	412,637
Current portion, long-term debt	(112,607)	—
Current portion of finance lease obligations	(1,166)	(717)
Total long-term debt	$ 697,405	$ 411,920

ABS Notes

In connection with the ABS Financing Transaction (see Note 4 – Acquisitions and Divestitures), on October 26, 2023, ABS Issuer acquired certain oil and natural gas interests in currently-producing oil and natural gas wells and other assets from Unbridled pursuant to an asset purchase agreement and the acquisition was funded by the issuance of the ABS Notes (as defined in Note 4 – Acquisitions and Divestitures), due December 2038, pursuant to a note purchase agreement. At December 31, 2023, the ABS Notes were comprised of the following:

	2023
	(in thousands of dollars)
Series 2023 – 1 Class A-1 8.121% Notes	$ 285,000
Series 2023 – 1 Class A-2 8.946% Notes	260,000
Series 2023 – 1 Class B 12.436% Notes	95,000
Total ABS Notes	640,000

The ABS Notes are secured by certain oil and natural gas interests in currently producing oil and natural gas wells and other assets. The ABS Notes accrue interest at the respective stated per annum rates and have a final maturity date of December 15, 2038. Interest and principal payments are payable on a monthly basis. During the period ended December 31, 2023, we incurred $10.3 million of interest related to the ABS Notes.

The ABS Notes are subject to a series of covenants and restrictions customary for transactions of this type, including (i) that the Issuer maintains specified reserve accounts to be used to make required interest payments in respect of the ABS Notes, (ii) provisions relating to optional and mandatory prepayments and the related payment of specified amounts, including specified make-whole payments under certain circumstances, (iii) certain indemnification payments in the event, among other things, that the assets pledged as collateral are used in stated ways defective or ineffective, (iv) covenants related to recordkeeping, access to information and similar matters, and (v) the Issuer will comply with all laws and regulations which it is subject to. The ABS Notes are also subject to customary accelerated amortization events provided for in the indenture, including events tied to failure to maintain stated debt service coverage ratios, failure to maintain certain production metrics, certain change of control and management termination events, and event of default and the failure to repay or refinance the ABS Notes on the applicable scheduled maturity date. The ABS Notes are subject to certain customary events of default, including events relating to non-payment of required interest, principal, or other amounts due on or with respect to the ABS Notes, failure to comply with covenants within certain time frames, certain bankruptcy events, breaches of specified representations and warranties, failure of security interests to be effective and certain judgments.

Under the indenture, the Company must maintain the following financial covenants determined as of the last day of the quarter: 1) Aggregate Debt Service Coverage Ratio (DSCR) less than 1.05, 2) Senior DSCR less than 1.25

As of December 31, 2023, we were in compliance with our covenants under the ABS Notes.

Senior Secured Reserve-Based Credit Facility

In connection with the Permian Acquisition (see Note 4 - Acquisitions and Divestitures), on January 27, 2022, we entered into an agreement with a syndicate of banks including JPMorgan Chase Bank acting as Administrator, Royal Bank of Canada, Citizens Bank, KeyBank National Association acting as co syndication agents, RBC Capital Markets, and KeyBank Capital Markets (the "**Credit Facility**"). The agreement is for a maximum $1 billion credit facility with an initial $500 million borrowing base. The maturity date is April 1, 2026. The Credit Facility replaced the Credit Agreement (defined below) subsequent to its closing on April 1, 2022, incurring deferred financing costs of $16.3 million.

The Credit Facility limits the amounts we could borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. Our obligations under the credit facility were collateralized by substantially all of our oil and natural gas properties, including mortgage liens on oil and natural gas properties having at least 85% of the reserve value as determined by reserve reports.

The Credit Facility contains certain customary affirmative and negative covenants, including financial covenants requiring maintenance of the Consolidated Total Debt to EBITDAX Ratio to be less than 3.00 to 1.00 and a Current Ratio of no less than 1.00 to 1.00.

At our election, borrowings under the credit facility may be made on an Alternate Base Rate ("**ABR**") or a Secured Overnight Financing Rate ("**SOFR**") basis plus an applicable margin. In connection with the Credit Facility, the applicable margins vary from 2.00% to 3.00% for ABR borrowings and 3.00% to 4.00% for SOFR borrowings depending on the borrowing base. In addition, we are also required to pay a commitment fee on the amount of any unused commitments at a rate of 0.50% per annum. Interest on ABR borrowings and the commitment fee are generally payable quarterly. As of December 31, 2023, the effective interest rate of the Credit Facility was 9.24%.

In June 2022, we entered into an amendment to the Credit Facility (the "**First Amendment**") which increased the borrowing base from the initial $500 million to $750 million. Each lender's borrowing capacity was increased with the exception of Goldman Sachs Bank, and we accounted for the First Amendment as a modification of debt. We incurred deferred financing costs of $2.6 million in relation to this amendment.

In October 2022, we entered into the second amendment to the Credit Facility (the "**Second Amendment**"), which increased the borrowing base to $1 billion. Each lender's borrowing capacity was increased with the exception of Texas Capital Bank, and we accounted for the Second Amendment as a modification of debt. We incurred deferred financing costs of $2.6 million in relation to this amendment.

In July 2023, we entered into the third amendment to the Credit Facility (the "**Third Amendment**"), which reduced the borrowing base from $1 billion to $750 million. Each lender's borrowing capacity was decreased, and we accounted for the Third Amendment as a modification of debt. Additionally, the Third Amendment allowed for a one-time cash distribution to our equity holders not to exceed $10 million in aggregate through 30 September 2023. We did not incur deferred financing costs in relation to the Third Amendment.

In October 2023 in conjunction with the ABS Financing Transaction, we entered into the fourth amendment to the Credit Facility (the "**Fourth Amendment**"), which amended in its entirety the original Credit Facility. Pursuant to the Fourth Amendment, among other things, the borrowing base was reduced from $750 million to $350 million, and the respective reduced commitments of the various lending banks were reallocated among the continuing lenders to assign the exiting lenders' commitment. We accounted for the decreases in a lender's borrowing capacity as a modification and accounted for any lender that exited the credit facility as a debt extinguishment. In connection with ABS, we repaid $0.0 million as of December 31, 2023.

We incurred deferred financing costs of $5.6 million in relation to the Fourth Amendment. At December 31, 2023, our borrowing base is $350.0 million, and the aggregate commitment of all lenders is $1 billion. Our next borrowing base redetermination is scheduled for April 1, 2024.

Unamortized debt issuance costs associated with the Credit Facility were $13.2 million as of December 31, 2023.

As of December 31, 2023, we were in compliance with our debt covenants under the Credit Facility.

Credit Agreement

On October 24, 2018, BOLP, as borrower, entered into a $1.0 billion credit agreement with Maverick Natural Resources, LLC as the parent guarantor, JPMorgan Chase Bank, N.A., as the administrative agent, collateral agent and letter of credit issuer, Royal Bank of Canada, as syndication agent and other syndicate financial institutions (the "**Lenders**") (the "**Credit Agreement**"). The Credit Agreement had a maturity date of October 24, 2023, and was replaced by the Credit Facility (discussed above) effective April 1, 2022.

Interest Expense

Our interest expense is as follows:

	2023	2022
	(in thousands of dollars)	
Credit Facility[(1)]	$ 40,828	$ 18,566
ABS Notes[(2)]	10,307	—
Amortization of deferred debt issuance costs, Credit Facility	10,274	6,462
Amortization of deferred debt issuance costs, ABS Notes	581	—
Other Credit Facility, net	186	81
	$ 62,176	$ 21,109
(1) Includes commitment fees and other fees	$ 2,733	$ 2,738
(2) Includes commitment fees and other fees	$ —	$ —

11. Asset Retirement Obligations

We recognize the fair value of a liability for an ARO in the period it is incurred if a reasonable estimate of fair value can be made. Our ARO represents the present value of the expected costs to plug, abandon and remediate producing and shut-in wells at the end of the productive lives in compliance with applicable local, state and federal laws and applicable lease terms. We estimate the value of our ARO by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The ARO liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and natural gas properties using the unit-of-production method. We review our ARO estimates and assumptions periodically and, to the extent future revisions to these assumptions impact the fair value of the existing ARO liability, we make a corresponding adjustment to the related asset. We consider these inputs to be Level 3 inputs as discussed in Note 2 – Summary of Significant Accounting Policies and Note 5 – Financial Instruments and Fair Value Measurements.

The following table presents the balance and activity in our ARO for the periods presented:

	2023	2022
	(in thousands of dollars)	
Asset retirement obligations, beginning of year	$ 253,281	$ 225,817
Liabilities incurred from drilling	—	769
Liabilities settled	(19,839)	(7,335)
Liabilities related to divested properties[(1)]	(9,970)	(6,345)
Liabilities related acquired properties[(2)]	—	22,916
Revisions of estimates[(3)]	11,535	3,036
Accretion expense[(4)]	14,666	14,425
Asset retirement obligations end of year	249,673	253,281
Less: Current portion of asset retirement obligations	(7,282)	(5,060)
Noncurrent portion of asset retirement obligations	$ 242,391	$ 248,221

Notes:

(1) Includes ARO related to various sold properties. See Note 4 – Acquisitions and Divestitures.

(2) Related to ARO acquired from Permian and Anadarko acquisitions. See Note 4 – Acquisitions and Divestitures.

(3) During the periods presented, we revised our estimates primarily to reflect the following changes in estimated well lives, oil and natural gas prices and plugging and abandonment cost estimates.

(4) Included in DD&A on our consolidated statements of operations.

12. Commitments and Contingencies

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At both December 31, 2023 and 2022, we had $21.3 million of irrevocable letters of credit outstanding, of which $21.0 million related to the property reclamation deposit as discussed in Note 8 – Other Long-Term Assets. At December 31, 2023, no amounts were drawn under the letters of credit.

Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings, other than litigation in regards to the Jay Field NPI. As of December 31, 2023, we had accrued $4.2 million related to this litigation. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statues to which we are subject.

13. Equity

Common Units

During 2023, we repurchased 3,222 units for $1.5 million for certain members and executives.

Member Distributions

In October 2022, the Board approved a distribution of totaling $120 million at $41.43 per common unit to the common unitholders of record on the applicable record date.

In January 2023, the Board approved a distribution of $30 million at $10.36 per common unit to the common unitholders of record on the applicable record date.

In May 2023, the Board approved two distributions totaling $50 million. The first distribution was $30 million at 10.36 per common unit to the common unitholders of record on the applicable record date. The second distribution was $20 million at $6.91 per common unit to the common unitholders of record on the applicable record date.

In October 2023, the Board approved a distribution of $260 million at $89.76 per common unit to the common unitholders of record on the applicable record date.

The state of Oklahoma requires operators to withhold 5% of all production revenues associated with royalty interests held by Oklahoma nonresidents to be offset against state income taxes. As Maverick is not subject to income taxes as a limited liability company, the tax liability associated with the operations of Unbridled is the responsibility of the members. As such, the balance of Oklahoma state withholding has been reflected as an equity distribution. At December 31, 2023 and 2022, the total distributions attributable to Oklahoma state withholding is $0.6 million and $0.4 million, respectively.

14. Compensation

Defined Contribution Plan

We sponsor a 401(k) defined contribution plan for eligible employees, and the Plan includes a provision for employer matching contributions. We recorded general and administrative expenses for our matching contributions totaling $2.4 million and $1.3 million for the years ended December 31, 2023 and 2022, respectively.

Long Term Incentive Plans

Maverick Natural Resources, LLC Long Term Incentive Plan (or the "**LTIP**") was effective and approved by the Board in August 2019. The LTIP provides for the compensation of employees and eligible nonemployee directors of the Company and its subsidiaries by granting Incentive Units to employees and directors with 3-year and 1-year vesting terms, respectively, from the grant date. The Incentive Unit awards are accounted for as liability-classified awards that will settle in cash and reported as accounts payable and accrued expenses in our consolidated balance sheets. Forfeitures associated with the LTIP awards granted are recognized when they occur.

The Incentive Unit Amounts upon vesting are payable in cash and is equal to the quotient of the Implied Equity Value as of the last day of the fiscal year preceding the Vesting Event provided, that, in the case of vesting due to an Exit Event or Asset Sale, the Implied Equity Value is, in the sole discretion of the Administrator, either (i) the Implied Equity Value as of the last day of the fiscal year preceding such Vesting Event, or (ii) the Implied Equity Value as of another appropriate date determined by the Administrator, divided by a fixed number subject to adjustment by the Administrator. The Implied Equity Value means an amount equal to the quotient of Adjusted EBITDA and Peer Multiple, less Net Debt, plus Cumulative Distributions. The value of each LTIP unit at December 31, 2023 was estimated at $78.34 per unit. The fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 measurement within the fair value hierarchy.

In August 2023, the Company granted long-term incentive awards to various executives in the form of cash. The Awards are subject to time-based vesting conditions.

The following table summarizes liability-classified performance unit activity for the years ended December 31, 2023 and 2022 and provides information for unvested units as of December 31, 2023 and 2022:

	Number of Units
Unvested units at December 31, 2021	95,814
Granted	88,524
Forfeited	(30,305)
Vested	(57,909)
Unvested units at December 31,2022	96,124
Granted	108,473
Forfeited	(20,068)
Vested	(64,194)
Unvested units at December 31, 2023	120,335

The Company recognized cash-based long-term incentive compensation of $1.3 million and $1.0 million for executive awards in general and administrative expense in our consolidated statement of operations for both the years ended December 31, 2023 and 2022.

Equity Incentive Awards

For equity classified awards, we recognize expense for the grant date fair value of the award over the vesting period of the awards. Forfeitures are accounted for as they occur. The grant date fair value of the common units was derived from an estimate of Enterprise Value, or the fair value of our upstream and midstream businesses and long-term debt and liabilities. Significant inputs used to determine the fair values of properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by our management at the time of the valuation and are sensitive and subject to change.

In August 2023, the Company granted executive incentive awards to various executives in the form of common units. The Awards are subject to performance-based vesting conditions based on market conditions. The expected term for awards granted in 2023 is 1.4 to 2.4 years. The Company did not grant any awards in 2022.

The Company recognized non-cash unit-based compensation of $1.6 million in general and administrative expense in our consolidated statement of operations for the year ended December 31, 2023. The weighted average grant date fair value for the award was $309.13 per common unit. As of December 31, 2023, 28,900 common units have been granted, 16,895 common units remain unvested, and unamortized compensation expense is $4.9 million over the next four years.

The Company recognized non-cash unit-based compensation of $1.2 million in general and administrative expense in our consolidated statement of operations for the year ended December 31, 2022. The weighted average grant date fair value for the award was $333.16 per common unit. As of December 31, 2022, 17,222 common units have been granted, 8,663 common units remain unvested, and unamortized compensation expense is $3.2 million over the next four years.

15. Restructuring Costs

In 2023 and 2022, as part of the Company's restructuring plan, we incurred restructuring costs of approximately $1.6 million and $0.3 million, respectively, primarily related to plans for reductions in workforce to improve operational efficiencies.

Restructuring costs recorded in our consolidated statements of operations are presented for the respective periods:

	2023	2022
	(in thousands of dollars)	
Type of restructuring cost	$ 1,485	$ 120
Severance and related benefit costs	146	163
Office-lease abandonment and relation	$ 1,631	$ 283

16. Subsequent Events

The Company has evaluated subsequent events through April 29, 2024, the date the financial statements were issued and noted the events below.

In February 2024, the Company replaced the performance-based equity incentive awards granted in August 2023 with time-based equity incentive awards.

In March 2024, the Company settled its Jay Field litigation for $9.2 million. As part of the settlement, the Company purchased the net profit interest in the Jay Field for approximately $5 million. The Company recognized a litigation settlement accrual as of December 31, 2023 for $4.2 million.

SECTION B

REPORT OF INDEPENDENT AUDITORS

To the Board of Managers of Maverick Natural Resources, LLC

Opinion

We have audited the accompanying consolidated financial statements of Maverick Natural Resources, LL and its subsidiaries (the "**Company**"), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of operations, members' equity, and cash flows for the years then ended, including the related notes (collectively referred to as the "**consolidated financial statements**").

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the consolidated financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

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In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

Houston, Texas

April 29, 2024

SECTION C

MAVERICK NATURAL RESOURCES, LLC AND SUBSIDIARIES

Unaudited Consolidated Financial Statements

September 30, 2024

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Balance Sheets (Unaudited)
September 30, 2024 and December 31, 2023

	September 30, 2024	December 31, 2023
	Thousands of dollars	
Assets		
Current assets		
Cash	$ 40,137	$ 53,263
Restricted cash - current	36,736	31,936
Accounts receivable, net	127,889	140,260
Derivative instruments	37,581	46,503
Inventory	9,666	2,209
Prepaid expenses and other current assets	6,535	7,089
Total current assets	258,544	281,260
Property, plant and equipment		
Oil and natural gas properties	2,391,401	2,674,820
Other property, plant and equipment	119,920	110,888
Property, plant and equipment	2,511,321	2,785,708
Accumulated depletion, depreciation, and impairment	(1,047,475)	(1,097,788)
Property, plant and equipment, net	1,463,846	1,687,920
Other long-term assets		
Assets held-for-sale - noncurrent	90,291	–
Derivative instruments	23,151	48,018
Operating lease right-of-use assets	11,534	12,362
Other long-term assets	33,260	35,577
Total assets	$ 1,880,626	$ 2,065,137
Liabilities and Equity		
Current liabilities		
Accounts payable and accrued expenses	$ 220,839	$ 272,637
Current portion of long-term debt	110,254	113,773
Derivative instruments	-	98
Current portion of asset retirement obligation	7,282	7,282
Operating lease obligations - current	1,477	841
Liabilities related to assets held-for-sale	13,401	–
Total current liabilities	353,253	394,631
Long-term debt	657,292	697,405
Derivative instruments	548	3,994
Asset retirement obligation	226,248	242,391
Operating lease obligations - noncurrent	24,932	25,316
Liabilities related to assets held-for-sale - noncurrent	16,957	–
Other long-term liabilities	29,785	29,501
Total liabilities	1,309,015	1,393,238
Members' equity	571,611	671,899
Total liabilities and equity	$ 1,880,626	$ 2,065,137

The accompanying notes are an integral part of these consolidated financial statements.

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Operations (Unaudited)
Nine Months Ended September 30, 2024 and 2023

	Year to Date September 30, 2024	Year to Date September 30, 2023
	Thousands of dollars	
Revenues and other income items		
Oil revenues	$ 421,209	$ 465,331
Natural gas revenues	77,601	119,439
NGL revenues	78,111	85,248
Oil, natural gas and NGL revenues	576,921	670,018
Loss on commodity derivative instruments	(2,322)	(27,341)
Other revenues, net	60,881	65,067
Total revenues and other income items	635,480	707,744
Operating costs and expenses		
Operating costs	353,810	372,859
Depletion, depreciation and amortization	130,491	119,186
Impairment of oil and natural gas properties	110,856	62,683
General and administrative expenses	45,638	55,010
Restructuring costs	8,822	1,600
Gain on sale of assets	(2,206)	(1,022)
Total operating costs and expenses	647,411	610,316
Operating income (loss)	(11,931)	97,428
Interest expense	63,558	41,810
Other income, net	(2,680)	(842)
Total other expense (income)	60,878	40,968
Income (loss) before taxes	(72,809)	56,460
Income tax expense (benefit)	148	(416)
Net income (loss)	$ (72,957)	$ 56,876

The accompanying notes are an integral part of these consolidated financial statements.

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity (Unaudited)
Period ended September 30, 2024 and 2023

	Outstanding Common Units	Total Members' Equity
	Thousands of dollars	
Balances, December 31, 2022	**2,896**	**$ 755,148**
Unit-based compensation	–	(410)
Units issued under unit-based compensation awards, net of tax withholdings	2	1,321
Net income	–	56,876
Redemption of units	(1)	(1,538)
Distributions	–	(80,000)
Other	–	(220)
Balances, December 31, 2023	**2,897**	**671,899**
Units issued under unit-based compensation awards, net of tax withholdings	5	3,092
Net loss	–	(72,957)
Redemption of units	(1)	(1,145)
Unit-based compensation modified to liability awards	(9)	(4,682)
Distributions	–	(24,242)
Other	–	(354)
Balances, September 30, 2024	**2,892**	**571,611**

The accompanying notes are an integral part of these consolidated financial statements.

Maverick Natural Resources, LLC and Subsidiaries
Consolidated Statements of Cash Flows (Unaudited)
Nine Months Ended September 30, 2024 and 2023

	Nine Months Ended September 30,	
	2024	2023
	Thousands of dollars	
Cash flows from operating activities		
Net income (loss)	$ (72,957)	$ 56,876
Adjustments to reconcile cash flow from operating activities:		
Depletion, depreciation and amortization	130,491	119,186
Impairment of oil and natural gas properties	110,856	62,683
(Gain) loss on derivative instruments	2,322	27,341
Derivative instrument settlement payments	27,923	(34,819)
Deferred income taxes	–	(397)
Gain on sale of assets	(2,206)	(1,022)
Restructuring costs, net of payments	2,498	93
Write off of debt issuance costs	1,556	3,678
Other	8,672	1,520
Changes in assets and liabilities:		
Accounts receivable and other assets	2,737	47,961
Inventory	(2,352)	(1,615)
Accounts payable and accrued expenses	(29,048)	(53,687)
Net cash provided by operating activities	180,492	227,798
Cash flows from investing activities		
Capital acquisitions, net	(14,683)	(17,367)
Capital expenditures	(104,416)	(227,185)
Proceeds from sale of assets	1,799	15,514
Net cash used in investing activities	(117,300)	(229,038)
Cash flows from financing activities		
Distributions to common unitholders	(24,242)	(80,000)
Credit facility borrowings	160,500	315,000
Repayments of credit facility	(126,500)	(245,000)
Issuance of term debt	10,000	–
Repayments of term debt	(88,464)	–
Long-term debt issuance costs	–	(114)
Redemption of common units	(1,928)	(1,538)
Principal payments on finance lease obligations	(884)	(672)
Net cash used in financing activities	(71,518)	(12,324)
Increase (decrease) in cash and restricted cash	(8,326)	(13,564)
Cash and restricted cash - beginning of period	85,199	16,806
Cash and restricted cash - end of period	$ 76,873	$ 3,242

The accompanying notes are an integral part of these consolidated financial statements.

Maverick Natural Resources, LLC and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
As of September 30, 2024 and December 31, 2023 and for the nine-month periods September 30, 2023

1. Nature of Operations

Maverick Natural Resources, LLC ("**MNR**" or "**Parent**") and its subsidiaries, including Maverick Asset Holdings LLC ("**MAH**"), Maverick ABS Holdco, LLC ("**ABS Holdco**"), and Maverick Services, LLC ("**MAV Services**"), (collectively, "**Maverick**," "**we**" or the "**Company**") is a Delaware limited liability company formed on March 22, 2018. We are a Houston, Texas-based oil and natural gas company focused on the development and production of long-lived oil and natural gas reserves throughout the United States. Our primary operations are in seven regions in the United States: East Texas, Mid-Continent (Western Oklahoma and Eastern New Mexico); Permian (West Texas); Rockies (Wyoming); Southeast (Southwest Florida, Florida Panhandle and Alabama); and Western Anadarko (Texas Panhandle and Southwestern Oklahoma).

On October 26, 2023, the Parent, through its consolidated subsidiaries, raised $640 million through an asset-backed securitization financing transaction. Several new subsidiaries were created including MNR ABS Holdings I, LLC ("**ABS Holdings**") and MNR ABS Issuer I, LLC ("**ABS Issuer**"). See Note 4 – Acquisitions, Divestitures, and Assets Held for Sale – Transactions Between Entities Under Common Control and Note 9 – Debt for further discussion.

In January 2025, the Company entered into a definitive merger agreement with Diversified Energy Company PLC ("Diversified"), pursuant to which Diversified will acquire all the outstanding equity interest of the Company. For additional information, see Note 14 – Subsequent Events.The Company operates its properties through its primary operating subsidiaries: Breitburn Operating, L.P. ("**BOLP**"), Unbridled Resources, LLC ("**Unbridled**"), and Maverick Permian, LLC.

In addition to our operating companies, the Company's subsidiaries include: (i) Wheeler Midstream, LLC, an oil terminal located in Wheeler County, TX, which purchases oil from both properties operated by Unbridled, a wholly owned entity, and third-party operated properties, (ii) MidPoint Midstream, LLC, a gas gathering operation located in Wheeler and Hemphill Counties, Texas and Roger Mills and Beckham Counties, Oklahoma, which gathers and compresses natural gas produced from Unbridled and third party operated properties, and (iii) Bluebonnet Resources, LLC, which acquired unproved acreage for development purposes.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our unaudited consolidated financial statements relate to our financial position as of September 30, 2024 and December 31, 2023, and our results of operations for the nine months ended September 30, 2024 and September 30, 2023, respectively. They reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited financial statements, with the exception of any recently adopted accounting pronouncements. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted, although the Company believes that the disclosures are adequate to make the information presented not misleading. Our consolidated financial statements include Maverick and our wholly owned or majority-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Recently Adopted Accounting Standards

In June 2016, the Financial Accounting Standards Board ("**FASB**") issued Accounting Standards Update ("**ASU**") No. 2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("**ASU 2016-13**"), which changes the impairment model for most financial assets. The ASU introduces a new credit loss methodology, Current Expected Credit Losses (CECL), which requires earlier recognition of credit losses, while also providing additional transparency about credit risk. Since its original issuance in 2016, the FASB has issued several updates to the original ASU. The CECL framework utilizes a lifetime "expected credit loss" measurement objective for the recognition of credit losses for loans, held-to-maturity securities, and other receivables at the time the financial asset is originated or acquired. The expected credit losses are adjusted each period for changes in expected lifetime credit losses. The methodology replaces the multiple existing impairment methods, which generally require that a loss be incurred before it is recognized.

On January 1, 2023, the Company adopted the guidance applying the modified retrospective basis approach. The adoption of this standard did not have a material impact on the Company's consolidated financial statements as of the adoption date, January 1, 2023.

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("**ASU 2020-04**"), which provided optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that referenced LIBOR ("**London Inter-Bank Offered Rate**") or another rate. ASU 2020-04 was in effect through December 31, 2022. In January 2021, the FASB issued ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope ("**ASU 2021-01**"), to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848" ("**ASU 2022-06**"), which defers the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. As of September 30, 2024, the Company's borrowings under its Credit Facility bear interest at an ABR or SOFR basis plus an applicable margin and the ABS loans have a fixed interest rate. At this time, the Company does not plan to enter into additional contracts using LIBOR as a reference rate. For additional information, see Note 9 – Debt.

In October 2021, the FASB issued ASU 2021-07, "Compensation – Stock Compensation (Topic 718): Determining the Current Price of an Underlying Share for Equity-Classified Share-Based Awards" as a practical expedient to allow a nonpublic entity to determine the current price input of equity-classified share-based awards issued to both employees and nonemployees using the reasonable application of a reasonable valuation method. The practical expedient describes the characteristics of the reasonable application of a reasonable valuation method as the same characteristics used in the regulations of the U.S. Department of Treasury for income tax purposes (the "Treasury Regulations"). Consequently, a reasonable valuation performed in accordance with the Treasury Regulations is an example of a way to achieve the practical expedient. This accounting standard had no effect on the Company and the company continues to use a reasonable valuation method for its equity classified awards.

In March 2023, the FASB issued an ASU to amend certain provisions of Accounting Standards Codification ("**ASC**") Topic 842, "Leases" ("**ASC 842**") that apply to arrangements between related parties under common control. The ASU amends the accounting for the amortization period of leasehold improvements in common-control leases for all entities and requires certain disclosures when the lease term is shorter than the useful life of the asset. This ASU is effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. Early adoption is permitted. This accounting standard had no effect on the Company and the Company will continue to evaluate the standard in the future.

New Pronouncements Issued But Not Yet Adopted

In November 2024, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2024-03, "Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40)," which expands disclosures around an entity's costs and expenses of specific items (i.e. employee compensation, DD&A), requires the inclusion of amounts that are required to be disclosed under GAAP in the same disclosure as other disaggregation requirements, requires qualitative descriptions of amounts remaining in expense captions that are not separately disaggregated quantitatively, and requires disclosure of total selling expenses, and in annual periods, the definition of selling expenses. The amendment does not change or remove existing disclosure requirements. The amendment is effective for fiscal years beginning after December 15, 2026, and interim periods with fiscal years beginning after December 15, 2027. Early adoption is permitted, and the amendment can be adopted prospectively or retrospectively to any or all periods presented in the financial statements. The Company is currently assessing the impact of adopting this standard.

Use of Estimates

The preparation of financial statements and related footnotes in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

Our significant estimates include oil and natural gas reserves; cash flow estimates used in impairment testing of oil and natural gas properties and midstream assets; depreciation, depletion, amortization ("**DD&A**") and accretion; asset retirement obligations ("**ARO**"); accrued revenue and related receivables; operating expenses and accrued liabilities; valuation of liability-classified incentive awards; mark-to-market valuations; and unit-based compensation. We believe our estimates are reasonable, and actual results could differ significantly from these estimates.

Cash and Restricted Cash

Our cash consists of cash in the bank. Current restricted cash represents funds held in escrow that will be used to settle certain general unsecured claims related to the 2018 bankruptcy and cash held in a liquidity reserve account, collection account, and plug and abandonment account maintained in connection with the ABS Financing Transaction. As of September 30, 2024, the amounts in Restricted Cash consisted of $3.2 million, $20.4 million, $12.1 million, and $0.9 million for the escrow, liquidity reserve, collection, and plug and abandonment accounts, respectively. As of December 31, 2023, the amounts in Restricted Cash consisted of $3.2 million $23.6 million, and $5.1 for the escrow, liquidity reserve, and collection accounts, respectively. As of September 30, 2024 and December 31, 2023, long-term restricted cash did not have a balance.

Revenue Recognition and Natural Gas Balancing

We recognize revenues from the sale of oil, natural gas and natural gas liquid ("**NGL**") when control of the oil, natural gas and NGL production has transferred to the customer, the transaction price has been determined and collectability is reasonably assured and evidenced by a contract. Performance obligations under our contracts with customers are typically satisfied when oil, natural gas and NGL are transferred through delivery at the inlet of pipeline or processing plant, onloading to the delivery truck or barge.

Oil terminal revenues are recognized when delivery to the purchaser has occurred, title has transferred, and the associated receivable is recoverable.

We generate gathering revenues by providing gathering and compression services to third parties. We recognize revenue for these arrangements over time based on a per unit rate applied to volumes that travel through the gathering system. In addition, we retain any drip liquids collected on our gathering systems. The value of these drip liquids is recognized as part of gathering revenue in the month the underlying gathering service is provided based upon the price realized for sale of drip condensate to third party customers which represents a market price.

Natural gas production imbalances represent the fair value of amounts payable or receivable for natural gas production imbalances, and revenues are recognized based on our share of volumes sold, regardless of whether we have taken our proportional share of volume produced. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of September 30, 2024 and December 31, 2023, our natural gas production imbalance asset of $3.8 million and $3.1 million, respectively, was included in other long-term assets and natural gas production imbalance liability of $22.7 million and $21.8 million, respectively, was included in other long-term liabilities on our consolidated balance sheets.

Inventory

Inventory represents our share of crude oil produced from our Florida and Texas operations that is held in storage tanks and unsold at the end of the period. Inventory is reported as current assets in our consolidated balance sheets and carried at the lower of cost or market. We assess the carrying value of our inventory periodically to determine any adjustments necessary to reduce the carrying value to net realizable value. Uncertainties that may impact our assessment include: the applicable quality and location differentials and changes in the timing of a sale. We did not recognize any write-downs during the periods presented.

Property, Plant and Equipment

Proved Oil and Natural Gas Properties

We account for oil and natural gas exploration and development activities using the successful efforts method. Under this method, all property acquisition and development costs are capitalized when incurred and depleted on a unit-of-production basis over total proved reserves and proved developed reserves, respectively. Proved leasehold costs associated with proved reserves are depleted based on total proved reserves, which include proved undeveloped reserves.

Costs of retired, sold or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds to accumulated DD&A unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently in the consolidated statements of operations.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties include lease acquisition costs which are costs incurred to acquire unproved leases. Lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated lease acquisition costs. Lease acquisition costs that are expensed are recorded as "impairment of oil and natural gas properties" in our consolidated statements of operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Natural Gas Properties

We evaluate proved oil and natural gas properties for impairment whenever facts or circumstances indicate that the carrying values of such properties may not be recoverable. We perform impairment assessments by grouping assets at the lowest level for which there are identifiable cash flows. Impairment is indicated when a triggering event occurs and/or the sum of the estimated future net cash flows of an evaluated asset group is less than the asset group's carrying value. Triggering events may include potential disposition of assets and declines in oil, natural gas and NGL prices. If impairment is indicated, we estimate fair value using a discounted cash flow approach. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with risk and current market conditions associated with realizing the expected cash flows projected.

We evaluate unproved oil and natural gas properties periodically for impairment on a geographic basis based on remaining lease terms, drilling results or future plans to develop acreage. These factors may be affected by economic factors including future oil and natural gas prices and projected capital costs.

We evaluate the recoverability of our other property, plant and equipment whenever events or circumstances indicate a decline in the recoverability of the respective carrying values may have occurred. We compare the net carrying value of the asset group to the undiscounted net cash flows projected. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount to fair value.

Impairment expense for proved and unproved properties is reported as “impairment of oil and natural gas properties” in the consolidated statements of operations. Impairment expense for other property, plant and equipment is reported as “impairment of long-lived assets” in the consolidated statements of operations.

Other Property, Plant and Equipment

Other property, plant and equipment include buildings, field equipment, compressors, furniture, leasehold improvements, computer hardware and software. We record other property, plant and equipment at cost and depreciate the assets using the straight-line method over the estimated lives of the individual assets.

We assign the useful lives of our property, plant and equipment based upon our internal estimates that are reviewed by management periodically. We use estimated lives of 20 years for our buildings, two to seven years for field equipment, furniture and computer hardware and software, and the remaining lease term for leasehold improvements. At the time of sale or disposal, the costs and accumulated DD&A of the sold or disposed assets are removed from our consolidated balance sheets with any gain or loss realized in our consolidated statements of operations.

Midstream Assets

Midstream assets consist primarily of natural gas gathering facilities and pipelines, as well as an oil terminal. Renewals and betterments, which substantially extend the useful lives of the assets, are capitalized and reported as other property, plant and equipment in our consolidated balance sheets. Maintenance and repairs are expensed when incurred. These assets are depreciated using the straight-line method over 3 to 30 years. We consider estimated future dismantlement, restoration and abandonment costs in our calculation of straight-line DD&A for our natural gas gathering, processing facilities and pipelines.

Leases

At inception, contracts are assessed for the presence of a lease according to the criteria prescribed by Accounting Standards Codification (“**ASC**”) Topic 842, “Leases” (“**ASC 842**”). If a lease is present, further criteria is assessed to determine if the lease should be classified as an operating or finance lease. Operating leases are presented on the consolidated balance sheet as operating lease right-of-use assets with the corresponding lease liabilities presented as operating lease obligations - current and Operating lease obligations - noncurrent. Finance lease assets are presented on the consolidated balance sheet as other property, plant and equipment with the corresponding liabilities presented in current portion of long-term debt and long-term debt.

Generally, lease liabilities are recognized at commencement and based on the present value of the future minimum lease payments to be made over the lease term. Lease assets are then recognized based on the value of the lease liabilities. For leases where the implicit lease rates are not determinable, the minimum lease payments are discounted using the Company’s collateralized incremental borrowing rates.

Operating leases are expensed according to their nature and recognized in operating expenses or general and administrative expenses. Finance leases are depreciated and amortized with the relevant expenses recognized in depreciation, depletion and amortization and interest expense on the consolidated statement of operations.

Revenue and Production Taxes Payable

We calculate and pay taxes and royalties on crude oil and natural gas in accordance with particular contractual provisions of the leases, license or concession agreements and the laws and regulations applicable to those agreements.

Asset Retirement Obligations

We recognize estimated liabilities for future costs associated with the abandonment of our oil and natural gas properties, gas gathering, processing facilities and pipelines. We record a liability for the fair value of an ARO and a corresponding increase to the carrying value of the related long-lived asset in the period in which wells are drilled or acquired. See Note 10 – Asset Retirement Obligations for further discussion.

Liability-Classified Awards

We classify certain awards that will be settled in cash as liability awards in our consolidated balance sheets in accounts payable and accrued expenses. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense and operating costs over the vesting period of the award. The Company's liability-classified awards include a performance condition based on preceding Implied Equity Value. See Note 5 – Financial Instruments and Fair Value Measurements for further discussion.

Unit-Based Compensation

Unit-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards is recognized on a straight-line basis over the requisite service period.

Environmental Liabilities

We are subject to federal, state and local environmental laws and regulations. These laws regulate the release, disposal or discharge of materials into the environment or otherwise relate to environmental protection. These laws and regulations may require that we remove or mitigate the environmental effect of the discharge, disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. We expense expenditures related to an existing condition caused by past operations that have no future economic benefit. We record liabilities for noncapital expenditures when environmental assessments or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability is fixed or determinable. We did not have environmental liabilities at September 30, 2024 and December 31, 2023, respectively.

Business Combinations and Asset Acquisitions

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition-date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of the proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average costs of capital rate are subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into exchange for such properties.

Any excess of the acquisition price over the estimated fair value of net assets acquired in recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded as a bargain purchase gain in other income, net on our consolidated statements of operations.

In an asset acquisition, transaction costs are capitalized, and any excess or deficit of fair value of net assets in relation to acquisition price is allocated to the acquired assets based on the relative fair value.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine that it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the mostly likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss.

Fair Value of Financial Instruments

Certain of our financial assets and liabilities are measured at fair value. Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Our financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 5 – Financial Instruments and Fair Value Measurements for additional details.

Fair Value of Nonfinancial Assets and Liabilities

We apply fair value accounting guidance to measure our nonfinancial assets and liabilities such as those obtained through property, plant and equipment, AROs and restructuring. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. Under the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and natural gas production and other applicable sales estimates, operational costs and risk-adjusted discount rate. We may use the present value of estimated future cash inflows and outflows, third-party offers or prices of comparable assets with consideration of the current market conditions to value our nonfinancial assets and liabilities when circumstances dictate fair value determination is necessary.

Concentrations of Credit Risk

We are subject to credit risk resulting from the concentration of our oil, natural gas and NGL receivables with the following major purchasers that accounted for 10% or more of our total oil, natural gas and NGL sales for the periods presented:

	Nine Months Ended September 30,	
Purchaser	**2024**	**2023**
Customer A	15%	12%
Customer B	13%	6%
Customer C	12%	12%

Our financial instruments with credit risk exposure consist principally of cash, accounts receivable, and derivative instruments. We maintain cash in deposit accounts at financial institutions that may exceed the federally insured limits. We monitor credit risk exposure by (i) placing our assets and other financial instruments with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include our evaluation of customers' financial condition and monitoring payment history and (iii) netting derivative assets and liabilities where we have legal right of offset with counterparties and diversifying our derivative instrument portfolio.

Risk Management and Derivative Instruments

We have entered into derivative contracts with counterparties to reduce the effect of changes in oil and natural gas prices on a portion of our oil and natural gas production. We do not enter into such contracts for speculative trading purposes. Our commodity derivative instruments are measured at fair value in our consolidated balance sheets as derivative assets or derivative liabilities. We have not designated any derivative instruments as hedges for accounting purposes. Gains and losses from valuation changes in commodity derivatives are reported as (gain) loss on commodity derivative instruments in our consolidated statements of operations. Our cash flows are only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. Cash settlements are reflected as operating activities in our consolidated statements of cash flows. We expense transaction costs related to the modification of derivative instruments as incurred. See Note 5 – Financial Instruments and Fair Value Measurements for further discussion of our derivative instruments.

We have market and credit risk exposure due to commodity derivatives that are concentrated with certain counterparties who are affiliate lenders under the Credit Agreement. We believe the risk of nonperformance by our counterparties is low as we execute our derivative contracts only with credit-worthy financial institutions and we have no past-due receivables from our derivative counterparties. As of September 30, 2024, J. ARON & Company, JP Morgan Chase Bank N.A., and KeyBank, which accounted for approximately 60%, 39%, and 1%, respectively, of our total hedge settlement receivable.

Our commodity derivative contracts are documented with industry standard contracts known as Schedule to the Master Agreement and International Swaps and Derivatives Association, Inc. Master Agreement ("**ISDA**"). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. We are not required to provide any credit support to our counterparties other than cross collateralization with the oil and natural gas properties securing the Credit Agreement. We have certain limitations under the Credit Agreement, including a provision that limits the total amount of our production that may be hedged to certain percentages of current and forecasted production. As of September 30, 2024, we were in compliance with these limitations. See Note 5 – Financial Instruments and Fair Value Measurements and Note 9 – Debt for additional information.

Debt Issuance Costs

Debt issuance costs related to our Credit Facility and ABS Notes are amortized over the life of the related debt using the effective interest rate method and unamortized debt issuance costs are netted against the outstanding balance of debt obligations on our consolidated balance sheets. Any unamortized costs associated with retired debt are written off and included in the determination of gain or loss on extinguishment of debt.

Revenues

Sales of oil, natural gas and NGL are recognized at the point when control of the commodity is transferred to the customer and collectability is reasonably assured. Most of our contracts' pricing provisions are tied to a commodity market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with the other available oil, natural gas and NGL suppliers.

Oil Sales

Under our crude purchase and marketing contracts, we generally sell oil production at the wellhead and collect an agreed-upon index price, net of pricing differentials. We recognize revenue when control transfers to the purchaser at the wellhead or delivery point for onloading to delivery truck or barge at the net price received.

Natural Gas and NGL Sales

Under our natural gas gathering, processing and purchase contracts, we deliver unprocessed natural gas to processing plants at the wellhead or the inlet of the processing plant's system. The midstream entity then gathers and processes the natural gas to produce residue gas and NGLs generated from processing. In the majority of cases, the midstream entity remits payment to us for NGLs based on index-based pricing or weighted average sales proceeds less deductions which may include gathering, processing and transportation fees, while the residue gas is redelivered to us at the tailgate of the midstream entity's processing plant for marketing under separate contracts. We sell residue gas at the delivery point specified in the separate contract and collect an agreed-upon index price, net of pricing differentials. Transportation, gathering and processing costs incurred after control transfers to the purchaser are recognized as reductions to revenues rather than as operating costs.

Oil Terminal Sales

Under our oil terminal sales contracts, we sell oil at the delivery point specified in the contract and collect an agreed-upon index price, net of pricing differentials. Control as defined under ASC 606, "Revenue from Contracts with Customers" ("**ASC 606**") passes at the delivery point. The delivery point is the point at which the oil passes the last permanent delivery flange or meter connecting our facility to customer's facility. At the delivery point, the customer takes physical custody, title and risk of loss of the product and we have a right to receive payment for the sale. We recognize revenue at the net price received when control transfers to the customer. Oil terminal sales are reported in other revenues, net on our consolidated statements of operations.

Gathering Revenue

We generate gathering revenues by providing gathering and compression services to third parties, which are reported in other revenues, net on our consolidated statement of operations. We recognize revenue for these arrangements over time based on a per unit rate applied to volumes that travel through the gathering system. In addition, we retain any drip liquids collected on our gathering systems. The value of these drip liquids is recognized as part of gathering revenue in the month the underlying gathering service is provided based upon the price realized for sale of drip condensate to third party customers which represents a market price.

Purchased Condensate Sales

The Company's purchased oil and natural gas sales are derived from the sale of oil and natural gas purchased from a third party and reported in other revenues, net on our consolidated statements of operations. Revenues and expenses from these sales and purchases are generally recorded on a gross basis, as the Company acts as a principal in these transactions by assuming control of the purchased oil or natural gas before it is transferred to the customer.

Performance Obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. We record revenue on our oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the production is delivered.

We have elected practical expedients, pursuant to ASC 606, to exclude from the presentation of remaining performance obligations: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue under the right to invoice practical expedient.

Contract Balances

We invoice our customers when we have satisfied our performance obligations, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to third party purchasers. Accounts receivable is held at cost. At each reporting date, the Company assesses the expected lifetime credit losses on initial recognition of accounts receivable. At September 30, 2024, the credit loss allowance on accounts receivable was $5.8 million, and no credit losses were recorded during the nine months ended September 30, 2024. At December, 2023, the credit loss allowance on accounts receivable from joint interest owners was $5.8 million, and no credit losses were recorded during the nine months ended September 30, 2023.

3. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Nine Months Ended September 30,	
	2024	2023
	Thousands of dollars	
Cash payments		
Interest	$ 64,337	$ 33,606
Taxes	161	7
Noncash investing activities		
(Increase) decrease in accrued capital expenditures	$ 12,228	$ (1,413)
(Increase) decrease in asset retirement obligations	(2,986)	(10,657)
(Increase) decrease in assets under operating leases	–	(10,939)
(Increase) decrease in liabilities for asset divestitures	(628)	3,580
Noncash financing activities		
(Increase) decrease in assets under finance leases	(35)	–
Reconciliation of cash and restricted cash reported in the consolidated balance sheets		
Cash	$ 40,137	$ 10
Restricted cash	36,736	3,232
Total cash and restricted cash shown in the statement of cash flows	$ 76,873	$ 3,242

4. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions

During the nine months ended September 30, 2024 and 2023, the Company did not have any material acquisitions.

Transactions Between Subsidiaries of the Company

On October 26, 2023, Unbridled entered into an asset purchase agreement with ABS Issuer (the "**Purchase and Sale Agreement**"). Unbridled agreed to sell and transfer to ABS Issuer certain operated and non-operated oil and natural gas wells and all oil and natural gas leases, subleases and leasehold covering such wells (the "**ABS Assets**" and such transfer, the "**ABS Asset Transfer**") for a purchase price of $640 million, of which $630 million was cash and $10 million was a non-cash note payable, which was subsequently issued to a third party in January 2024 for $10 million in cash and accrued interest of $0.2 million.

In connection with the transaction, ABS Issuer entered into an indenture with UMB Bank, N.A. as indenture trustee (the "**Indenture Trustee**") (the "**Indenture**") to which ABS Issuer issued (a) $640 million aggregate principal amount of Series 2023-1 Notes, consisting of (i) $285 million aggregate principal amount of its 8.121% Series 2023-1 Notes, Class A-1 Notes due December 2038, (ii) $260 million aggregate principal amount of its 8.946% Series 2023-1 Notes, Class A-2 Notes due December 2038 and (iii) $95 million aggregate principal amount of its 12.436% Series 2023-1 Notes, Class B Notes due December 2038 (collectively, the "**ABS Notes**") and (b) pledged the ABS Assets to the Indenture Trustee to secure the ABS Issuer's obligations under the Indenture (the "**ABS Financing Transaction**").

In addition the following events occurred in connection with the transaction: (i) $10 million of the ABS Notes were issued to Maverick, (ii) a holdback of $5.4 million related to consents not received at the date of the transaction which is reflected as restricted cash, (iii) a Liquidity Reserve Account was established for $23.6 million and is reflected as restricted cash, (iv) $260 million was an equity distribution and (v) repaid $300 million for the Credit Facility.

We incurred hedge novation fees of $4.6 million in conjunction with the ABS Financing Transaction which were expensed as incurred in general and administrative expenses in our consolidated statement of operations. We incurred $12.7 million of costs including legal fees and administrative fees in connection with the ABS Financing

Transaction which were capitalized as deferred financing costs and recorded as an offset to the carrying value of the ABS Notes.

Divestitures

In May 2024, we entered into an agreement with a third party to divest certain properties in west Texas. The divestiture was executed without a purchase price, and the Company received no financial consideration for the transaction. We recognized a $2.2 million gain on the sale for the nine months ended September 30, 2024. The gain was primarily due to relief of related asset retirement obligations.

In March 2023, we entered into an agreement with a third party to divest certain interests in oil and natural gas properties, rights and related assets in Western Anadarko Basin for a purchase price of $10.0 million. This sale was accounted for as a normal retirement under the provisions of paragraph ASC 932-360-40-3 with no gain or loss recorded on the sale for the nine months ended September 30, 2023.

In May 2023, we entered into an agreement with a third party to divest certain properties in west Texas for a purchase price of $4.5 million. We recognized a $0.3 million gain on the sale for the nine months ended September 30, 2023.

Assets Held for Sale

In August 2024, the Company entered into two agreements with two separate third parties to sell certain East Texas assets (the "**East Texas Sale**") for a combined purchase price totaling $97.0 million. As of September 30, 2024, the held for sale criteria were met. The related oil and natural gas properties, other property and equipment, asset retirement obligations, and revenue in suspense are classified as held for sale and presented separately in the appropriate asset and liability sections of the consolidated balance sheet. The transactions closed in October 2024.

5. Financial Instruments and Fair Value Measurements

Commodity Activities

At September 30, 2024, our commodity derivatives consisted of fixed price swaps and two-way costless collars. Our fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor). The two-way collars are a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling). For both swaps and collars, all transactions are settled in cash for the net difference between settlement and contract prices, multiplied by the hedged contract volumes, for the settlement period.

Our commodity derivative contracts settle monthly based on the differential between the contract price and the average NYMEX West Texas Intermediate index price ("**NYMEX WTI**") (oil), average NYMEX Henry Hub index price ("**NYMEX HH**") (natural gas) and Mont Belvieu Oil Price Information Service ("**OPIS**") (NGLs). The following table presents derivative positions for the periods indicated as of September 30, 2024:

	2024	2025	2026	2027	2028	2029	2030
Oil Positions							
Fixed Price Swaps - NYMEX WTI							
Volume (Bbl/d)	13,450	11,926	10,623	3,688	3,366	–	–
Average Price ($/Bbl)	$ 71.88	$ 71.85	$ 68.45	$ 65.95	$ 62.21	$ –	$ –
Costless Collar - NYMEX WTI							
Volume (Bbl/d)	1,000	–	–	–	–	–	–
Average Put Price ($/Bbl)	$ 67.00	$ –	$ –	$ –	$ –	$ –	$ –
Average Call Price ($/Bbl)	$ 80.35	$ –	$ –	$ –	$ –	$ –	$ –
Total							
Volume (Bbl/d)	14,450	11,926	10,623	3,688	3,366	–	–
Average Price ($/Bbl)	$ 72.01	$ 71.85	$ 68.45	$ 65.95	$ 62.21	$ –	$ –

	2024	2025	2026	2027	2028	2029	2030
Gas Positions							
Fixed Price Swaps - Henry Hub							
Volume (MMBtu/d)	106,285	108,838	86,514	69,070	61,056	50,962	47,714
Average Price ($/MMBtu)	$ 3.49	$ 3.89	$ 3.87	$ 3.76	$ 3.63	$ 3.41	$ 3.27
Costless Collar - Henry Hub							
Volume (Bbl/d)	10,000	–	10,000	–	–	–	–
Average Put Price ($/Bbl)	$ 2.50	$ –	$ 3.50	$ –	$ –	$ –	$ –
Average Call Price ($/Bbl)	$ 5.80	$ –	$ 5.15	$ –	$ –	$ –	$ –
Total							
Volume (MMBtu/d)	116,285	108,838	96,514	69,070	61,056	50,962	47,714
Average Price ($/MMBtu)	$ 3.54	$ 3.89	$ 3.87	$ 3.76	$ 3.63	$ 3.41	$ 3.27
NGL Positions							
Fixed Price Swaps							
Volume (Bbl/d)	10,500	8,661	6,127	–	–	–	–
Average Price ($/Bbl)	$ 0.91	$ 0.88	$ 0.83	$ –	$ –	$ –	$ –
Total							
Volume (Bbl/d)	10,500	8,661	6,127	–	–	–	–
Average Price ($/Bbl)	$ 0.91	$ 0.88	$ 0.83	$ –	$ –	$ –	$ –
Fixed Gas Basis Swap							
Volume (Bbl/d)	90,219	84,068	77,423	–	–	–	–
Average Price ($/MMBtu)	$ (0.19)	$ (0.26)	$ (0.23)	$ –	$ –	$ –	$ –

Balance Sheet Presentation

The following table summarizes the fair value of the derivatives outstanding on a gross and net basis:

	September 30, 2024				
	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Commodity Derivatives Netting[1]	Total Financial Instruments
	Financial Statement Caption, thousands of dollars				
Assets					
Current assets - derivative instruments	$ 21,632	$ 28,369	$ 10,634	$ (23,054)	$ 37,581
Other long-term assets - derivative instruments	13,825	32,174	8,968	(31,816)	23,151
Total assets	35,457	60,543	19,602	(54,870)	60,732
Liabilities					
Current liabilities - derivative instruments	$ (23)	$ (4,162)	$ (18,869)	$ 23,054	–
Long-term liabilities - derivative instruments	(2,457)	(17,085)	(12,822)	31,816	(548)
Total liabilities	(2,480)	(21,247)	(31,691)	54,870	(548)
Net assets	$ 32,977	$ 39,296	$ (12,089)	$ –	$ 60,184

	December 31, 2023				
	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Commodity Derivatives Netting[1]	Total Financial Instruments
	Financial Statement Caption, thousands of dollars				
Assets					
Current assets - derivative instruments	$ 7,539	$ 39,124	$ 18,958	$ (19,118)	$ 46,503
Other long-term assets - derivative instruments	30,451	39,797	23,686	(45,917)	48,018
Total assets	37,990	78,921	42,645	(65,035)	94,521

	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Commodity Derivatives Netting[(1)]	Total Financial Instruments
	December 31, 2023				
	Financial Statement Caption, thousands of dollars				
Liabilities					
Current liabilities - derivative instruments	$ (2,897)	$ (1,931)	$ (14,388)	$ 19,118	$ (98)
Long-term liabilities - derivative instruments	(24)	(29,261)	(20,625)	45,917	(3,994)
Total liabilities	(47,594)	(31,193)	(35,013)	65,035	(4,092)
Net liabilities	$ (32,705)	$ (45,238)	$ 7,632	$ –	$ 90,429

Note:

(1) Represents counterparty netting under our ISDA Agreements. See Note 2 – Summary of Significant Accounting Policies. For our derivative contracts, we may enter into master netting, collateral and offset agreements with counterparties. These agreements provide us the ability to offset a counterparty's rights and obligations, request additional collateral when necessary, or liquidate the collateral in the event of counterparty default. We net the fair value of cash collateral paid or received against fair value amounts recognized for net derivative positions executed with the same counterparty under the same master netting or offset agreement.

The following table summarizes the unrealized gains/losses on commodity derivatives, which are included in the "loss on commodity derivative instruments" line of the consolidated income statement:

	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Total Financial Instruments
	in thousands of dollars			
Nine Months Ended September 30, 2024	(2,092)	(8,433)	(19,721)	(30,246)
Nine Months Ended September 30, 2023	(38,207)	37,977	7,708	7,478

The following table summarizes the realized gains/losses on commodity derivatives, which are included in the "loss on commodity derivative instruments" line of the consolidated income statement:

	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	NGL Commodity Derivatives	Total Financial Instruments
	in thousands of dollars			
Nine Months Ended September 30, 2024	(15,214)	53,333	(10,196)	27,923
Nine Months Ended September 30, 2023	(25,832)	5,620	(14,608)	(34,820)

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We measure certain assets and liabilities at fair value, using the fair value hierarchy noted below. We use valuation techniques that maximize the use of observable inputs and obtain the majority of our inputs from published objective sources or third-party market participants. We incorporate the impact of nonperformance risk, including credit risk, into our fair value measurements. The fair value hierarchy gives the highest priority of Level 1 to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority of Level 3 to unobservable inputs. We categorize our fair value financial instruments based upon the objectivity of the inputs and how observable those inputs are. The three levels of inputs are described further as follows:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date.

Level 2 Inputs other than quoted prices that are included in Level 1. Level 2 includes financial instruments that are actively traded but are valued using models or other valuation methodologies. We consider the over the counter ("**OTC**") commodity derivative contracts in our portfolio to be Level 2.

Level 3 Inputs that are not directly observable for the asset or liability and are significant to the fair value of the asset or liability. Level 3 includes financial instruments that are not actively traded and have little or no observable data for input into industry standard models. We consider our liability-classified long term incentive plan awards and put option liability to be Level 3 liabilities. See Note 12 – Equity for additional details.

Our assessment of the significance of an input to its fair value measurement requires judgment and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels.

Commodity Derivative Instruments

Our commodity derivative instruments include oil, natural gas and NGL swaps and collars. The fair value of our commodity derivative instruments is based on upon a third-party preparer's calculation using mark-to-market valuation reports provided by our counterparties for monthly settlement purposes to determine the valuation of our derivative instruments. We do not have access to the specific proprietary valuation models or inputs used by our counterparties or third-party preparer.

We compare the third-party preparer's valuation to counterparty valuation statements and investigate any significant differences. Additionally, we analyze monthly valuation changes in relation to movements in crude oil and natural gas forward price curves. The fair values reflect nonperformance risk inherent in the transaction using current credit default swap values for each counterparty for asset positions and the Company's creditworthiness for liability positions. Accordingly, we recorded an adjustment to the fair value of our net derivative liability of $2.7 million and $4.5 million at September 30, 2024 and December 31, 2023, respectively.

Fair Value – Recurring Measurement Basis

The following table presents our financial assets and liabilities that were accounted for at fair value on a recurring basis on our consolidated balance sheets at September 30, 2024 and December 31, 2023 by level within the fair value hierarchy.

	September 30, 2024			
	Level 1	Level 2	Level 3	Total
		in thousands of dollars		
Commodity derivative instruments [1]				
Assets		115,603		115,603
Liabilities		(55,419)		(55,419)
Net assets (liabilities)	$ –	$ 60,184	$ –	$ 60,184

	December 31, 2023			
	Level 1	Level 2	Level 3	Total
		in thousands of dollars		
Commodity derivative instruments [1]				
Assets		159,557		159,557
Liabilities		(69,127)		(69,127)
Net assets (liabilities)	$ –	$ 90,429	$ –	$ 90,429

Note:

(1) The derivative fair values are based on analysis of each contract on a gross basis, excluding the impact of netting agreements with counterparties and reclassifications between long-term and short-term balances.

Fair Value – Nonrecurring Measurement Basis

Acquisitions and impairment of proved and unproved properties and other non-oil and natural gas properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of property as of the measurement date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil and condensate, natural gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. These inputs are not observable in the market and represent level 3 inputs. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

6. Long-Lived Assets and Impairment

Our long-lived assets are comprised of oil and natural gas properties and other property, plant and equipment for the periods presented:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Proved oil and natural gas properties[(1)]	$ 2,293,998	$ 2,548,263
Unproved oil and natural gas properties	97,403	126,557
Total oil and natural gas properties	2,391,401	2,674,820
Other property, plant and equipment	119,920	110,888
Less: Accumulated depletion, depreciation and amortization	(1,047,475)	(1,097,788)
Net property, plant and equipment	$ 1,463,846	$ 1,687,920

Note:

(1) Estimates of future asset retirement costs of $263.4 million and $260.4 million are included in our proved oil and natural gas properties at September 30, 2024 and December 31, 2023, respectively.

Costs are excluded from the amortization base until proved reserves are established or impairment is determined.

Long-Lived Assets Impairment

During the nine months ended September 30, 2024, we recorded impairment losses of $110.9 million on certain East Texas based assets detailed in Note 4 after entering into purchase and sale agreements for total consideration lower than the net book value of the asset group. During the nine months ended September 30, 2023, we recorded impairment losses of $62.7 million due to a significant decrease in commodity prices driven by a decrease in gas futures.

7. Other Long-Term Assets

Other long-term assets consist of the following:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Property reclamation	$ 12,381	$ 11,910
Unamortized debt issuance costs	9,078	13,206
Security deposits	1,458	1,735
Other	10,343	8,726
Total other long-term assets	$ 33,260	$ 35,577

Net Profit Interest

As of December 31, 2023, we held a 50% net profit interest ("**NPI**") related to Jay Field. The NPI is held 50% by Maverick and a third party ("**NPI Holder**"). Under the arrangement, the NPI is payable after: (i) funds are withheld, to the extent allowable each month under the arrangement, to pay for the NPI holder's share of future development costs and abandonment obligations, and (ii) we are reimbursed for the NPI holder's share of excess historical production costs. Once the NPI holder's share of the excess historical costs is reimbursed, the NPI will be payable monthly to the extent the NPI for that month exceeds the amount withheld for that month for future development costs and abandonment obligations.

In March 2024, the Company settled outstanding litigation related to the Jay NPI for $9.2 million, including $5.0 million to purchase the remaining 50% interest in the Jay NPI, and $4.2 million to settle all outstanding legal claims.

Property Reclamation Deposit

As of September 30, 2024 and December 31, 2023, we had a property reclamation deposit of $12.4 and $11.9 million, respectively, included in other long-term assets, held in an escrow account as security for future abandonment and remediation obligations for the Jay Field. We are required to maintain the escrow account in effect for three years after all abandonment and remediation obligations have been completed. The funds in the escrow account are not to be returned to us until the later of three years after satisfaction of all abandonment obligations or December 31, 2026. At certain dates subsequent to closing, we have the right to request a refund of a portion or all of the property reclamation deposit. The seller has the sole discretion to grant our refund request. In addition to the cash deposit, we are required to provide letters of credit. At September 30, 2024 and December 31, 2023, we had $21.0 million in letters of credit related to the property reclamation deposit.

8. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Accounts payable	$ 105,687	$ 112,218
Revenue and royalties payable	68,599	93,315
Wages and salaries payable	14,642	21,008
Accrued interest payable	4,906	12,100
Production and property taxes payable	19,252	22,217
Hedge settlement payables	4,820	8,911
Other current liabilities	2,933	2,868
Total accounts payable and accrued expenses	$ 220,839	$ 272,637

9. Debt

Our debt was comprised of the following:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Credit Facility	$ 224,000	$ 190,000
ABS Notes	551,536	640,000
Finance Lease Obligations	2,706	3,555
Debt issuance costs	(10,696)	(12,377)
Notes held by ABS parent	–	(10,000)
Total debt	767,546	811,178
Current portion, long-term debt	(108,965)	(112,607)
Current portion of finance lease obligations	(1,289)	(1,166)
Total long-term debt	$ 657,292	$ 697,405

ABS Notes

In connection with the ABS Financing Transaction (see *Note 4 – Acquisitions, Divestitures, and Assets Held for Sale*), on October 26, 2023, ABS Issuer acquired certain oil and natural gas interests in currently-producing oil and natural gas wells and other assets from Unbridled pursuant to an asset purchase agreement and the acquisition was funded by the issuance of the ABS Notes (as defined in *Note 4 – Acquisitions, Divestitures, and Assets Held for Sale*), due December 2038, pursuant to a note purchase agreement. At September 30, 2024 and December 31, 2023, the ABS Notes were comprised of the following:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Series 2023 - 1 Class A-1 8.121% Notes	$ 232,597	$ 285,000
Series 2023 - 1 Class A-2 8.946% Notes	239,166	260,000
Series 2023 - 1 Class B 12.436% Notes	79,773	95,000
Total ABS Notes	551,536	640,000

The ABS Notes are secured by certain oil and natural gas interests in currently producing oil and natural gas wells and other assets. The ABS Notes accrue interest at the respective stated per annum rates and have a final maturity date of December 15, 2038. Interest and principal payments are payable on a monthly basis. During the nine months ended September 30, 2024, we incurred $41.1 million of interest related to the ABS Notes.

The ABS Notes are subject to a series of covenants and restrictions customary for transactions of this type, including (i) that the Issuer maintains specified reserve accounts to be used to make required interest payments in respect of the ABS Notes, (ii) provisions relating to optional and mandatory prepayments and the related payment of specified amounts, including specified make-whole payments under certain circumstances, (iii) certain indemnification payments in the event, among other things, that the assets pledged as collateral are used in stated ways defective or ineffective, (iv) covenants related to recordkeeping, access to information and similar matters, and (v) the Issuer will comply with all laws and regulations which it is subject to. The ABS Notes are also subject to customary accelerated amortization events provided for in the indenture, including events tied to failure to maintain stated debt service coverage ratios, failure to maintain certain production metrics, certain change of control and management termination events, and event of default and the failure to repay or refinance the ABS Notes on the applicable scheduled maturity date. The ABS Notes are subject to certain customary events of default, including events relating to non-payment of required interest, principal, or other amounts due on or with respect to the ABS Notes, failure to comply with covenants within certain time frames, certain bankruptcy events, breaches of specified representations and warranties, failure of security interests to be effective and certain judgments.

Under the indenture, the Company must maintain the following financial covenants determined as of the last day of the quarter: 1) Aggregate Debt Service Coverage Ratio (DSCR) of at least 1.05, 2) Senior DSCR of at least 1.25, 3) Senior IO DSCR of at least 1.20.

As of September 30, 2024, we were in compliance with our covenants under the ABS Notes.

Senior Secured Reserve-Based Credit Facility

On January 27, 2022, we entered into an agreement with a syndicate of banks including JPMorgan Chase Bank acting as Administrator, Royal Bank of Canada, Citizens Bank, KeyBank National Association acting as co-syndication agents, RBC Capital Markets, and KeyBank Capital Markets (the "**Credit Facility**"). The agreement is for a maximum $1 billion credit facility with an initial $500 million borrowing base. The maturity date is April 1, 2026. The Credit Facility replaced the Credit Agreement (defined below) subsequent to its closing on April 1, 2022, incurring deferred financing costs of $16.3 million.

The Credit Facility limits the amounts we could borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. Our obligations under the credit facility were collateralized by substantially all of our oil and natural gas properties, including mortgage liens on oil and natural gas properties having at least 85% of the reserve value as determined by reserve reports.

The Credit Facility contains certain customary affirmative and negative covenants, including financial covenants requiring maintenance of the Consolidated Total Debt to EBITDAX Ratio to be less than 3.00 to 1.00 and a Current Ratio of no less than 1.00 to 1.00.

At our election, borrowings under the credit facility may be made on an Alternate Base Rate ("**ABR**") or a Secured Overnight Financing Rate ("**SOFR**") basis plus an applicable margin. In connection with the Credit Facility, the applicable margins vary from 2.00% to 3.00% for ABR borrowings and 3.00% to 4.00% for SOFR borrowings depending on the borrowing base. In addition, we are also required to pay a commitment fee on the amount of any unused commitments at a rate of 0.50% per annum. Interest on ABR borrowings and the commitment fee are generally payable quarterly. As of September 30, 2024, the effective interest rate of the Credit Facility was 8.87%.

In June 2022, we entered into an amendment to the Credit Facility (the "**First Amendment**") which increased the borrowing base from the initial $500 million to $750 million. Each lender's borrowing capacity was increased with the exception of Goldman Sachs Bank, and we accounted for the First Amendment as a modification of debt. We incurred deferred financing costs of $2.6 million in relation to this amendment.

In October 2022, we entered into the second amendment to the Credit Facility (the "**Second Amendment**"), which increased the borrowing base to $1 billion. Each lender's borrowing capacity was increased with the exception of Texas Capital Bank, and we accounted for the Second Amendment as a modification of debt. We incurred deferred financing costs of $2.6 million in relation to this amendment.

In July 2023, we entered into the third amendment to the Credit Facility (the "**Third Amendment**"), which reduced the borrowing base from $1 billion to $750 million. Each lender's borrowing capacity was decreased, and we accounted for the Third Amendment as a modification of debt. Additionally, the Third Amendment allowed for a one-time cash distribution to our equity holders not to exceed $10 million in aggregate through September 30, 2023. We did not incur deferred financing costs in relation to the Third Amendment.

In October 2023 in conjunction with the ABS Financing Transaction, we entered into the fourth amendment to the Credit Facility (the "**Fourth Amendment**"), which amended in its entirety the original Credit Facility. Pursuant to the Fourth Amendment, among other things, the borrowing base was reduced from $750 million to $350 million, and the respective reduced commitments of the various lending banks were reallocated among the continuing lenders to assign the exiting lenders' commitment. We accounted for the decreases in a lender's borrowing capacity as a modification and accounted for any lender that exited the credit facility as a debt extinguishment. In connection with the ABS financing transaction, we repaid $0.0 million as of December 31, 2023. We incurred deferred financing costs of $5.6 million in relation to the Fourth Amendment.

In September 2024, we entered into the fifth amendment to the Credit Facility (the "**Fifth Amendment**"), which, upon the close of the aforementioned East Texas Sale, reduced the borrowing base from $350 million to $315 million. Each lender's borrowing capacity was decreased, and we accounted for the Fifth Amendment as a modification of debt, resulting in a $1.5 million write off of deferred financing costs to interest expense. Additionally, the Fifth Amendment allowed for distribution of stock proceeds from the East Texas Sale. At September 30, 2024, our borrowing base is $315.0 million, and the aggregate commitment of all lenders is $1 billion. Our next borrowing base redetermination is scheduled for May 1, 2025.

Unamortized debt issuance costs associated with the Credit Facility were $9.1 million as of September 30, 2024. The unamortized debt issuance costs are included in other long-term assets.

As of September 30, 2024, we were in compliance with our debt covenants under the Credit Facility.

Interest Expense

Our interest expense is as follows:

	Nine Months Ended September 30,	
	2024	**2023**
	in thousands of dollars	
Credit Facility[1]	$ 17,624	$ 33,972
ABS Notes	41,075	–
Amortization of deferred debt issuance costs, Credit Facility	2,875	7,704
Amortization of deferred debt issuance costs, ABS Notes	1,748	–
Other Credit Facility, net	237	134
	$ 63,559	$ 41,810
[1] Includes commitment fees and other fees	$ 646	$ 2,331

10. Asset Retirement Obligations

We recognize the fair value of a liability for an ARO in the period it is incurred if a reasonable estimate of fair value can be made. Our ARO represents the present value of the expected costs to plug, abandon and remediate producing and shut-in wells at the end of the productive lives in compliance with applicable local, state and federal laws and applicable lease terms. We estimate the value of our ARO by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The ARO liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and natural gas properties using the unit-of-production method. We review our ARO estimates and assumptions periodically and, to the extent future revisions to these assumptions impact the fair value of the existing ARO liability, we make a corresponding adjustment to the related asset. We consider these inputs to be Level 3 inputs as discussed in Note 2 – Summary of Significant Accounting Policies and Note 5 – Financial Instruments and Fair Value Measurements.

The following table presents the balance and activity in our ARO for the periods presented:

	September 30, 2024	December 31, 2023
	in thousands of dollars	
Asset retirement obligations, beginning of period	$ 249,673	$ 253,281
Liabilities settled	(9,977)	(19,839)
Liabilities related to divested properties[a]	(2,425)	(9,970)
Liabilities related to held for sale properties[a]	(16,957)	–
Revisions of estimates[b]	2,985	11,535
Accretion expense[c]	10,231	14,666
Asset retirement obligations end of period	233,530	249,673
Less: Current portion of asset retirement obligations	(7,282)	(7,282)
Noncurrent portion of asset retirement obligations	$ 226,248	$ 242,391

Notes:

(1) Includes ARO related to various sold or held for sale properties. See Note 4 – Acquisitions, Divestitures, and Assets Held for Sale.

(2) During the periods presented, we revised our estimates primarily to reflect the following changes in estimated well lives, oil and natural gas prices and plugging and abandonment cost estimates.

(3) Included in DD&A on our consolidated statements of operations.

11. Commitments and Contingencies

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily relate to abandonments, environmental and other responsibilities where governmental and other organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At both September 30, 2024 and December 31, 2023, we had $21.3 million of irrevocable letters of credit outstanding, of which $21.0 million related to the property reclamation deposit as discussed in Note 7 – Other Long-Term Assets. At September 30, 2024, no amounts were drawn under the letters of credit.

Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statues to which we are subject.

12. Equity

Common Units

During the nine months ended September 30, 2024, we repurchased 1,102 units for $1.1 million related to a certain terminated executive. As a result of recent executive terminations, the Company determined that there is an established history cash settling equity awards, which indicates that the substantive terms of the outstanding equity awards include a cash settlement feature, which results in a liability classification. The Company determined it appropriate to modify all outstanding equity awards to liability awards. This modification resulted in the reclassification from equity to liability awards of 8,960 units for $4.7 million. During the year ended December 31, 2023, we repurchased 3,222 units for $1.5 million for certain members and executives.

Member Distributions

There was a $0.2 million distribution in May 2024 related to a certain terminated executive. In September 2024, the Board approved a distribution of $24 million at $8.30 per common unit to the common unit holders on record on the applicable record date. In January 2023, the Board approved a distribution of $30 million at $10.36 per common unit to the common unitholders of record on the applicable record date. In May 2023, the Board approved two distributions totaling $50 million. The first distribution was $30 million at $10.36 per common unit to the common unitholders of record on the applicable record date. The second distribution was $20 million at $6.91 per common unit to the common unitholders of record on the applicable record date.

The state of Oklahoma requires operators to withhold 5% of all production revenues associated with royalty interests held by Oklahoma nonresidents to be offset against state income taxes. As Maverick is not subject to income taxes as a limited liability company, the tax liability associated with the operations of Unbridled is the responsibility of the members. As such, the balance of Oklahoma state withholding has been reflected as an equity distribution. At September 30, 2024 and 2023, the total distributions attributable to Oklahoma state withholding is $1.1 million and $0.6 million, respectively.

13. Restructuring Costs

For the nine months ended September 30, 2024 as part of the Company's restructuring plan, we incurred restructuring costs of approximately $8.8 million. For nine months ended September 30, 2023 we incurred restructuring costs of approximately $1.6 million. The costs incurred were primarily related to plans for reductions in workforce to improve operational efficiencies. Restructuring costs recorded in our consolidated statements of operations are presented for the respective periods:

	Nine Months Ended September 30,	
	2024	**2023**
	in thousands of dollars	
Type of restructuring cost		
Severance and related benefit costs	$ 8,729	$ 1,485
Office-lease abandonment and relocation	93	115
	$ 8,822	$ 1,600

14. Subsequent Events

The Company has evaluated subsequent events through February 11, 2025, the date the financial statements were issued and noted the events below.

In August 2024, the Company entered into two separate agreements to sell certain East Texas based assets (the "**East Texas Sale**") to two third parties. Total combined proceeds from the East Texas Sale totaled $97.0 million, of which $34.5 million was settled in shares of one of the purchasing entities. The East Texas Sale closed in Q4 2024.

In January 2025, the Company received a favorable verdict related to a civil claim against another operator. The court awarded $5.6M to the Company, subject to final appeals by the opposing party.

In January 2025, the Company entered into a definitive merger agreement with Diversified Energy Company PLC ("**Diversified**"), pursuant to which Diversified will acquire all the outstanding equity interest of the Company for total consideration of approximately $1.3 billion. The transaction is subject to customary closing conditions, including due diligence assessments and other closing requirements. The closing date of the transaction is expected to occur in the first half of 2025.

Part 4
UNAUDITED PRO FORMA FINANCIAL INFORMATION

Section A: Unaudited Pro Forma Financial Information

The unaudited pro forma condensed combined financial information ("**Unaudited Pro Forma Financial Information**") set out in this Section A of Part 4 has been prepared for illustrative purposes only and therefore does not represent the Group's actual results.

On 6 June 2024, the Company acquired Oaktree Capital Management, LP's 100% membership interest in OCM Denali Holdings, LLC and its subsidiaries (the "**Oaktree Transaction**"), whose assets predominantly included non-operated working interests in producing wells and related facilities (the "**Oaktree Assets**") that are operated by the Company. The Company paid purchase consideration of $220.8 million, inclusive of transaction costs of $1.2 million and customary purchase price adjustments. As part of the Oaktree Transaction, the Company assumed Oaktree's debt of $132.6 million. The Company funded the purchase through a combination of existing and expanded liquidity and issued approximately $83.3 million in notes payable to Oaktree.

On 24 January 2025, the Company entered into an agreement (the "**Agreement**") whereby Maverick will merge with a subsidiary of the Company in a stock-and-cash transaction (the "**Acquisition**"), after which Maverick will become a wholly-owned subsidiary of the Company. Under the terms of the Agreement, the Company will fund the Acquisition through a combination of the issue of 21,217,713 new Ordinary Shares to Maverick unitholders and pay cash consideration of $207.1 million. Transaction costs and severance and change in control costs incurred with the Acquisition are expected to be approximately $50 million. Completion is subject to certain customary conditions, including, among others, regulatory clearance and approval by Shareholders for the issue and allotment of the Consideration Shares. These closing conditions may not be completed in a timely manner or at all, and, accordingly, the Acquisition may not be completed.

The following Unaudited Pro Forma Financial Information is derived from the historical consolidated financial statements of the Company and historical Statements of Revenues and Direct Operating Expenses related to the Oaktree Transaction and the historical Consolidated Balance Sheet and Consolidated Statements of Operations related to the Acquisition. The Unaudited Pro Forma Financial Information only includes the impact of the Oaktree Transaction and the Acquisition and does not include other acquisitions, the Capital Raise, or any repayment of debt by the Company during the periods presented.

The Company accounted for the Oaktree Transaction as an asset acquisition under International Financial Reporting Standards ("**IFRS**"), as the assets and operations acquired in the Oaktree Transaction do not meet the definition of a business under IFRS 3. The Company expects to account for the Acquisition as a business combination under IFRS 3.

The Oaktree Transaction closed on 6 June 2024. Therefore, the Oaktree Transaction is included in the Company's Condensed Consolidated Statement of Financial Position as of 30 June 2024. The unaudited pro forma condensed combined statement of financial position was prepared as if the Acquisition had occurred on 30 June 2024. The unaudited pro forma condensed combined statements of operations for the six-month period ended 30 June 2024 and the year ended 31 December 2023 presented below were prepared as if the Oaktree Transaction and the Acquisition had occurred on 1 January 2023.

The Unaudited Pro Forma Financial Information reflects the following pro forma adjustments related to the Acquisition and the Oaktree Transaction, based on available information and certain assumptions that the Company believes are reasonable:

- adjustments for the Company's allocation of the preliminary purchase price and expected consideration paid to complete the Acquisition;

- adjustments for additional interest expense for the Company's related borrowing on its Credit Facility for the Acquisition and Oaktree Transaction, amortization of estimated financing costs related to the amendment to be entered into by the Company on the closing date of the Acquisition to increase the borrowing base capacity and commitment amounts on the Company's Credit Facility, the issuance of a note payable to Oaktree and the assumption of Oaktree's debt;

- adjustments for depletion expense related to the properties that were acquired in the Oaktree Transaction and those expected to be acquired in the Acquisition;
- adjustments for accretion expense associated with Oaktree's proportionate working interest in the asset retirement obligations, as well as the asset retirement obligations related to the properties expected to be acquired in the Acquisition;
- adjustments for the calculation of the weighted average shares outstanding and earnings per share for the shares expected to be issued as consideration in the Acquisition;
- adjustments for the impact of estimated transaction and severance and change in control costs expected to be incurred as a result of the Acquisition; and
- the recognition of estimated tax impacts of the pro forma adjustments.

Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read in conjunction with the Unaudited Pro Forma Financial Information. In the Company's opinion, all adjustments that are necessary to present fairly the pro forma information have been made.

The Unaudited Pro Forma Financial Information has been prepared on a consistent basis with the accounting policies adopted by the Group in relation to the consolidated financial statements for the six-month period ended 30 June 2024 and the year ended 31 December 2023. The adjustments made in the Unaudited Pro Forma Financial Information are expected to have a continuing impact on the Group, unless stated otherwise.

The Unaudited Pro Forma Financial Information is not intended to represent what the Company's results of operations would have been had the Oaktree Transaction and the Acquisition actually been consummated on the assumed date nor does it purport to project the future operating results of the combined company following the Oaktree Transaction and the Acquisition. The Unaudited Pro Forma Financial Information does not reflect future events that may occur after the Oaktree Transaction and the Acquisition, including, but not limited to, the anticipated realisation of ongoing savings from potential operating efficiencies, asset dispositions, cost savings, or economies of scale that the combined company may achieve with respect to the combined operations. Specifically, the unaudited pro forma condensed combined statement of operations does not include projected synergies expected to be achieved as a result of the Oaktree Transaction and the Acquisition and any associated costs that may be required to be incurred to achieve the identified synergies. The unaudited pro forma condensed combined statement of operations also exclude the effects of costs of integration activities and asset dispositions that may result from the Oaktree Transaction and the Acquisition.

No adjustments have been made to take account of the trading results or financial performance of the Group subsequent to the relevant date for each pro forma condensed combined statement of operations.

Users should read the whole of this document and not rely solely on Unaudited Pro Forma Financial Information. The accountant's report on the Unaudited Pro Forma Financial Information is set out in Section B "*Accountant's Report on the Unaudited Pro Forma Financial Information*" of Part 4 "*Unaudited Pro Forma Financial Information*" of this document.

Diversified Energy Company PLC Pro Forma
Condensed Combined Statement of Financial Position
As of June 30, 2024 (Unaudited)

	DEC Historical (Note 1)	Maverick As Adjusted (Note 2)	Acquisition Adjustments (Note 4)	Pro Forma Combined
		(In thousands)		
ASSETS				
Non-current assets:				
Natural gas and oil properties, net	$ 2,718,258	$ 1,579,386	$ (110,222)	$ 4,187,422
Property, plant and equipment, net	455,083	74,209	—	529,292
Intangible assets	15,664	6,814	(6,698)	15,780
Restricted cash	36,374	—	—	36,374
Derivative financial instruments	39,617	1,279	—	40,896
Deferred tax asset	248,868	—	—	248,868
Other non-current assets	13,637	45,590	—	59,227
Total non-current assets	**3,527,501**	**1,707,278**	**(116,920)**	**5,117,859**
Current assets:				
Trade receivables, net	180,017	134,534	—	314,551
Cash and cash equivalents	3,483	62,662	207,100 (207,100) (12,500)	53,645
Restricted cash	18,602	39,700	—	58,302
Derivative financial instruments	70,313	4,327	—	74,640
Other current assets	16,547	13,008	—	29,555
Total current assets	**288,962**	**254,231**	**(12,500)**	**530,693**
Total assets	**3,816,463**	**1,961,509**	**(129,420)**	**5,648,552**
EQUITY AND LIABILITIES				
Shareholders' equity:				
Share capital	$ 12,793	$ —	$ 5,305	$ 18,098
Share premium	1,208,192	—	346,274	1,554,466
Treasury reserve	(109,322)	—	—	(109,322)
Share-based payment and other reserves	15,889	—	—	15,889
Retained earnings (accumulated deficit)	(591,624)	588,425	(588,425) (49,945)	(641,569)
Equity attributable to owners of the parent	**535,928**	**588,425**	**(286,791)**	**837,562**
Non-controlling interest	12,370	—	—	12,370
Total equity	**548,298**	**588,425**	**(286,791)**	**849,932**
Non-current liabilities:				
Asset retirement obligations	510,935	244,213	(68,809)	686,339
Leases	29,309	25,458	—	54,767
Borrowings	1,442,986	681,377	(21,553) 207,100 (12,500)	2,297,410
Deferred tax liability	10,879	—	—	10,879
Derivative financial instruments	611,576	23,426	—	635,002
Other non-current liabilities	4,491	29,292	—	33,783
Total non-current liabilities	**2,610,176**	**1,003,766**	**104,238**	**3,718,180**
Current liabilities:				
Trade and other payables	60,482	225,051	—	285,533
Taxes payable	42,624	—	—	42,624
Leases	13,712	—	—	13,712
Borrowings	211,574	113,544	(5,257)	319,861
Derivative financial instruments	99,790	22,579	—	122,369
Other current liabilities	229,807	8,144	8,445 49,945	296,341
Total current liabilities	**657,989**	**369,318**	**53,133**	**1,080,440**
Total liabilities	**3,268,165**	**1,373,084**	**157,371**	**4,798,620**
Total equity and liabilities	**$ 3,816,463**	**1,961,509**	**$ (129,420)**	**$ 5,648,552**

See accompanying notes to the Unaudited Pro Forma Financial Information.

Diversified Energy Company PLC
Pro Forma Condensed Combined Statement of Operations
For the Six Months Ended June 30, 2024 (Unaudited)

	DEC Historical (Note 1)	Oaktree Historical (Note 1)	Maverick As Adjusted (Note 2)	Oaktree Transaction Adjustments (Note 3)		Acquisition Adjustments (Note 4)		Pro Forma Combined	
	(In thousands, except share and per unit data)								
Revenue	$ 368,674	$ 35,398	$ 435,980	$ 20,891	(a)	$ —		$ 860,943	
Operating expense	(196,112)	(19,344)	(239,681)	(8,562)	(a)	—		(463,699)	
Depreciation, depletion and amortization	(119,220)	—	(82,318)	(14,877)	(b)	22,718	(a)	(193,697)	
Gross profit	**53,342**	**16,054**	**113,981**	**(2,548)**		**22,718**		**203,547**	
General and administrative expense	(58,326)	—	(34,919)	—		—		(93,245)	
Allowance for expected credit losses	—	—	—	—		—		—	
Gain (loss) on natural gas and oil property and equipment	7,210	—	2,206	—		—		9,416	
Gain (loss) on sale of equity interest	—	—	—	—		—		—	
Unrealized gain (loss) on investment	2,433	—	—	—		—		2,433	
Gain (loss) on derivative financial instruments	(2,268)	—	(118,407)	—		—		(120,675)	
Impairment of proved properties	—	—	—	—		—		—	
Operating profit (loss)	**2,391**	**16,054**	**(37,139)**	**(2,548)**		**22,718**		**1,476**	
Finance costs	(60,581)	—	(41,844)	(10,684)	(c)	(10,640)	(b)	(123,749)	
Accretion of asset retirement obligation	(14,667)	—	(6,825)	(754)	(d)	1,078	(c)	(21,168)	
Loss on early retirement of debt	(10,649)	—	—	—		—		(10,649)	
Other income (expense)	1,254	—	1,715	—		—		2,969	
Income (loss) before taxation	**(82,252)**	**16,054**	**(84,093)**	**(13,986)**		**13,156**		**(151,121)**	
Income tax benefit (expense)	97,997	—	(160)	(497)	(e)	3,157	(d)	100,497	
Net income (loss)	**15,745**	**16,054**	**(84,253)**	**(14,483)**		**16,313**		**(50,624)**	
Other comprehensive income (loss)	(1,905)	—	—	—		—		(1,905)	
Total comprehensive income (loss)	**$ 13,840**	**$ 16,054**	**(84,253)**	**$ (14,483)**		**$ 16,313**		**$ (52,529)**	
Net income (loss) attributable to owners of the parent									
Diversified Energy Company PLC	$ 15,061	$ 16,054	$ (84,253)	$ (14,483)		$ 16,313		$ (51,308)	
Non-controlling interest	684	—	—	—		—		684	
Net income (loss)	**$ 15,745**	**$ 16,054**	**$ (84,253)**	**$ (14,483)**		**$ 16,313**		**$ (50,624)**	
Earnings (loss) per share attributable to owners of the parent									
Earnings (loss) per share - basic	$ 0.3	$ —	$ —	$ —		$ —		$ (0.75)	(e)
Earnings (loss) per share - diluted	$ 0.3	$ —	$ —	$ —		$ —		$ (0.75)	(e)
Weighted average shares outstanding - basic	47,202,283	—	—	—		—		68,419,996	(e)
Weighted average shares outstanding - diluted	47,561,299	—	—	—		—		68,419,996	(e)

See accompanying notes to the Unaudited Pro Forma Financial Information.

Diversified Energy Company PLC
Pro Forma Condensed Combined Statement of Operations
For the Year Ended December 31, 2023 (Unaudited)

	DEC Historical (Note 1)	Oaktree Historical (Note 1)	Maverick As Adjusted (Note 2)	Oaktree Transaction Adjustments (Note 3)		Acquisition Adjustments (Note 4)		Pro Forma Combined	
	(In thousands, except share and per unit data)								
Revenue	$ 868,263	$ 152,521	$ 977,390	$ —		$ —		$1,998,174	
Operating expense	(440,562)	(87,210)	(488,261)	—		—		(1,016,033)	
Depreciation, depletion and amortization	(224,546)	—	(151,822)	(38,720)	(b)	24,733	(a)	(390,355)	
Gross profit	**203,155**	**65,311**	**337,307**	**(38,720)**		**24,733**		**591,786**	
General and administrative expense	(119,722)	—	(84,949)	—		(49,945)	(b)	(254,616)	
Allowance for expected credit losses	(8,478)	—	—	—		—		(8,478)	
Gain (loss) on natural gas and oil property and equipment	24,146	—	1,090	—		—		25,236	
Gain (loss) on sale of equity interest	18,440	—	—	—		—		18,440	
Unrealized gain (loss) on investment	4,610	—	—	—		—		4,610	
Gain (loss) on derivative financial instruments	1,080,516	—	145,934	—		—		1,226,450	
Impairment of proved properties	(41,616)	—	(66,785)	—		—		(108,401)	
Operating profit (loss)	**1,161,051**	**65,311**	**332,597**	**(38,720)**		**(25,212)**		**1,495,027**	
Finance costs	(134,166)	—	(62,176)	(29,605)	(c)	(20,747)	(c)	(246,694)	
Accretion of asset retirement obligation	(26,926)	—	(14,666)	(1,809)	(d)	3,171	(d)	(40,230)	
Loss on early retirement of debt	—	—	—	—		—		—	
Other income (expense)	385	—	1,130	—		—		1,515	
Income (loss) before taxation	**1,000,344**	**65,311**	**256,885**	**(70,134)**		**(42,788)**		**1,209,618**	
Income tax benefit (expense)	(240,643)	—	(604)	1,160	(e)	(10,269)	(e)	(250,356)	
Net income (loss)	**759,701**	**65,311**	**256,281**	**(68,974)**		**(53,057)**		**959,262**	
Other comprehensive income (loss)	(270)	—	—	—		—		(270)	
Total comprehensive income (loss)	**$ 759,431**	**$ 65,311**	**256,281**	**$ (68,974)**		**$ (53,057)**		**$958,992**	
Net income (loss) attributable to owners of the parent									
Diversified Energy Company PLC	$ 758,018	$ 65,311	$ 256,281	$ (68,974)		$ (53,057)		$957,579	
Non-controlling interest	1,683	—	—	—		—		1,683	
Net income (loss)	**$ 759,701**	**$ 65,311**	**$ 256,281**	**$ (68,974)**		**$ (53,057)**		**$959,262**	
Earnings (loss) per share attributable to owners of the parent									
Earnings (loss) per share - basic	$ 16.07	$ —	$ —	$ —		$ —		$ 14.00	(f)
Earnings (loss) per share - diluted	$ 15.95	$ —	$ —	$ —		$ —		$ 13.93	(f)
Weighted average shares outstanding - basic	47,165,380	—	—	—		—		68,383,093	(f)
Weighted average shares outstanding - diluted	47,514,000	—	—	—		—		68,732,234	(f)

See accompanying notes to the Unaudited Pro Forma Financial Information.

Notes to Unaudited Pro Forma Financial Information

Note 1 – DEC Historical and Oaktree Historical – Basis of Pro Forma Presentation

The accompanying Unaudited Pro Forma Financial Information was prepared based on the historical consolidated financial statements of the Company for the year ended 31 December 2023 and the six months ended 30 June 2024 (which are incorporated by reference into this Prospectus pursuant to Part 8 ("*Documents Incorporated by Reference*")).

The Oaktree historical revenue and operating expense amounts are derived from the unaudited Oaktree historical Statement of Revenues and Direct Operating Expenses for the three months ended 31 March 2024 and the year ended 31 December 2023 (the "**Oaktree Q1 2024 Financial information**" and "**Oaktree 2023 Financial Information**", respectively, as described in the Presentation of Financial Information section of this Prospectus) and have been sourced from historical financial records related to the Oaktree Assets.

The Maverick historical financial information is derived from the Maverick historical unaudited and unpublished interim Consolidated Balance Sheet as of 30 June 2024, the audited Consolidated Statement of Operations for the year ended 31 December 2023 and the unaudited and unpublished interim Consolidated Statement of Operations for the six months ended 30 June 2024 (the "**Maverick Financial Information**"), as described in the Presentation of Financial Information section of this Prospectus. The Oaktree 2023 Financial Information, Oaktree Q1 2024 Financial Information and the Maverick Financial Information has not been audited in accordance with the International Standards on Auditing (UK) or reviewed in accordance with the International Standard on Review Engagements (UK). The Oaktree 2023 Financial Information, Oaktree Q1 2024 Financial Information and Maverick Historical Financial Information have been prepared in accordance with U.S. GAAP, while the accompanying pro forma adjustments have been prepared under IFRS. The Company has assessed the differences in the basis of accounting and, except as set out in Note 4, no material adjustments are required.

The unaudited pro forma condensed combined statement of operations for the six months ended 30 June 2024 and the year ended 31 December 2023 were prepared assuming the Acquisition and the Oaktree Transaction occurred on 1 January 2023. The unaudited pro forma condensed combined balance sheet as of 30 June 2024 was prepared as if the Acquisition had occurred on 30 June 2024. The Oaktree Transaction closed on 6 June 2024. Therefore, the Oaktree Transaction is already included in the Company's condensed consolidated statement of financial position as of 30 June 2024.

The Unaudited Pro Forma Financial Information reflects pro forma adjustments that are described in the accompanying notes and are based on currently available information and certain assumptions that the Company believes are reasonable, however, actual results may differ materially. In the Company's opinion, all adjustments that are necessary to present fairly the pro forma information have been made. The Unaudited Pro Forma Financial Information does not purport to represent what the Company's results of operations would have been if the Acquisition and the Oaktree Transaction had actually occurred on the date indicated above, nor is it indicative of the Company's future results of operations. The Unaudited Pro Forma Financial Information should be read in conjunction with the historical consolidated financial statements and related notes of the Company, as applicable, for the periods presented.

Note 2 - Maverick As Adjusted

Certain reclassifications have been made to the historical presentation of Maverick's financial statements to conform to the Company's historical presentation.

Balance Sheet as of June 30, 2024
(*In thousands*)

Maverick Caption	Diversified Caption	Maverick Historical	Reclassification Adjustments		Maverick As Adjusted
	ASSETS				
	Non-current assets:				
Oil and natural gas properties..............	Natural gas and oil properties, net........	$ 2,715,824	$ (1,136,438)	(1)	1,579,386

Maverick Caption	Diversified Caption	Maverick Historical	Reclassification Adjustments		Maverick As Adjusted
Other property, plant and equipment		118,804	(118,804)	(2)	—
Accumulated depletion, depreciation, and impairment		(1,174,219)	1,174,219	(1)	—
	Property, plant and equipment, net	—	74,209	(1) (2)	74,209
	Intangible assets	—	6,814	(2)	6,814
	Restricted cash	—	—		—
Derivative instruments	Derivative financial instruments	1,279	—		1,279
Operating lease right-of-use assets		11,803	(11,803)	(3)	—
	Deferred tax asset	—	—		—
Other long-term assets	Other non-current assets	33,787	11,803	(3)	45,590
	Total non-current assets	**1,707,278**	**—**		**1,707,278**
	Current assets:				
Accounts receivable, net	Trade receivables, net	134,534	—		134,534
Cash	Cash and cash equivalents	62,662	—		62,662
Restricted cash – current	Restricted cash	39,700	—		39,700
Derivative instruments	Derivative financial instruments	4,327	—		4,327
Inventory		8,113	(8,113)	(4)	—
Prepaid expenses and other current assets	Other current assets	4,895	8,113	(4)	13,008
	Total current assets	**254,231**	**—**		**254,231**
	Total assets	**1,961,509**	**—**		**1,961,509**
	EQUITY AND LIABILITIES				
	Shareholders' equity:				
	Share capital	—	—		—
	Share premium	—	—		—
	Treasury reserve	—	—		—
	Share-based payment and other reserves	—	—		—
Members' equity	Retained earnings (accumulated deficit)	588,425	—		588,425
	Equity attributable to owners of the parent	**588,425**	**—**		**588,425**
	Non-controlling interest	—	—		—
	Total equity	**588,425**	**—**		**588,425**
	Non-current liabilities:				
Asset retirement obligation	Asset retirement obligations	244,213	—		244,213
Operating lease obligations – noncurrent	Leases	25,458	—		25,458
Long-term debt	Borrowings	681,377	—		681,377
	Deferred tax liability	—	—		—
Derivative instruments	Derivative financial instruments	23,426	—		23,426
Other long-term liabilities	Other non-current liabilities	29,292	—		29,292
	Total non-current liabilities	**1,003,766**	**—**		**1,003,766**
	Current liabilities:				
Accounts payable and accrued expenses	Trade and other payables	225,051	—		225,051
Current portion of long-term debt	Borrowings	113,544	—		113,544
Derivative instruments	Derivative financial instruments	22,579	—		22,579
Current portion of asset retirement obligations		7,282	(7,282)	(5)	—
Operating lease obligation – current		**862**	**(862)**	(5)	**—**
	Other current liabilities	**—**	**8,144**	(5)	**8,144**
	Total current liabilities	**369,318**	**—**		**369,318**
	Total liabilities	**1,373,084**	**—**		**1,373,084**
	Total equity and liabilities	**$ 1,961,509**	**$ —**		**$ 1,961,509**

Notes:

(1) Represents the reclassification of balances contained in "Accumulated depletion, depreciation, and impairment" on Maverick's historical balance sheet to "Natural gas and oil properties, net" and "Property, plant and equipment, net" to conform to the Company's balance sheet presentation.

(2) Represents the reclassification of balances contained in "Other property, plant and equipment" on Maverick's historical balance sheet to "Property, plant and equipment, net" and "Intangible assets" to conform to the Company's balance sheet presentation.

(3) Represents the reclassification of balances contained in “Operating lease right-of-use assets” on Maverick’s historical balance sheet to “Other non-current assets” to conform to the Company’s balance sheet presentation.

(4) Represents the reclassification of balances contained in “Inventory” on Maverick’s historical balance sheet to “Other current assets” to conform to the Company’s balance sheet presentation.

(5) Represents the reclassification of balances contained in “Current portion of asset retirement obligations” and “Operating lease obligation - current” on Maverick’s historical balance sheet to “Other current liabilities” to conform to the Company’s balance sheet presentation.

Statement of Operations for the Six Months Ended June 30, 2024
(In thousands)

Maverick Caption	Diversified Caption	Maverick Historical	Reclassification Adjustments		Maverick As Adjusted
Oil revenues		$288,298	$ (288,298)	(1)	$ —
Natural gas revenues		52,087	(52,087)	(1)	—
NGL revenues		53,721	(53,721)	(1)	—
Other revenues, net		41,874	(41,874)	(1)	—
	Revenue	—	435,980	(1)	435,980
Operating costs	**Operating expense**	**239,681**	**—**	**(5)**	**(239,681)**
Depletion, depreciation and amortization	Depreciation, depletion and amortization	89,143	(6,825)	(2)(5)	(82,318)
	Gross profit	107,156	(6,825)		113,981
General and administrative expenses	General and administrative expense	31,043	3,876	(3)(5)	(34,919)
Restructuring costs		3,876	(3,876)	(3)	—
	Allowance for expected credit losses	—	—		—
(Gain) loss on sale of assets	Gain (loss) on natural gas and oil property and equipment	(2,206)	—	(6)	2,206
	Gain (loss) on sale of equity interest	—	—		—
	Unrealized gain (loss) on investment	—	—		—
Realized gain (loss) on commodity derivative instruments	Gain (loss) on derivative financial instruments	12,421	(130,828)	(4)	(118,407)
Unrealized gain (loss) on commodity derivative instruments		(130,828)	130,828	(4)	—
Impairment of oil and natural gas properties	Impairment of proved properties	—	—		—
	Operating profit (loss)	(43,964)	(6,825)		(37,139)
Interest expense	Finance costs	41,844	—	(5)	(41,844)
	Accretion of asset retirement obligation	—	6,825	(2)(5)	(6,825)
	Loss on early retirement of debt	—	—		—
Other income, net	Other income (expense)	(1,715)	—	(6)	1,715
	Income (loss) before taxation	**(84,093)**	**—**		**(84,093)**
Income tax expense (benefit)	Income tax benefit (expense)	160	—	(5)	(160)
	Net income (loss)	**(84,253)**	**—**		**(84,253)**
	Other comprehensive income (loss)	—	—		—
	Total comprehensive income (loss)	**$(84,253)**	**$ —**		**$(84,253)**

Notes:

(1) Represents the reclassification of amounts contained in "Oil revenues," "Natural gas revenues," "NGL revenues," and "Other revenues, net" on Maverick's historical income statement to "Revenue" to conform to the Company's income statement presentation.

(2) Represents the reclassification of amounts contained in "Depletion, depreciation and amortization" on Maverick's historical income statement to "Accretion of asset retirement obligation" to conform to the Company's income statement presentation.

(3) Represents the reclassification of amounts contained in "General and administrative expenses" and "Restructuring costs" on Maverick's historical income statement to "General and administrative expense" to conform to the Company's income statement presentation.

(4) Represents the reclassification of amounts contained in "Realized gain (loss) on commodity derivative instruments" and "Unrealized gain (loss) on commodity derivative instruments" on Maverick's historical income statement to "Gain (loss) on derivative financial instruments" to conform to the Company's income statement presentation.

(5) Represents the presentation on Maverick's historical income statement as a negative value to conform to the Company's income statement presentation.

(6) Represents the presentation on Maverick's historical income statement as a positive value to conform to the Company's income statement presentation.

Statement of Operations for the Twelve Months Ended December 31, 2023
(*In thousands*)

Maverick Caption	Diversified Caption	Maverick Historical	Reclassification Adjustments		Maverick As Adjusted
Oil revenues		$ 619,524	$ (619,524)	(1)	$ —
Natural gas revenues		161,054	(161,054)	(1)	—
NGL revenues		113,320	(113,320)	(1)	—
Other revenues, net		83,492	(83,492)	(1)	—
	Revenue	—	977,390	(1)	977,390
Operating costs	Operating expense	488,261	—	(4)	(488,261)
Depletion, depreciation and amortization	Depreciation, depletion and amortization	166,488	(14,666)	(2)(4)	(151,822)
	Gross profit	**322,641**	**(14,666)**		**337,307**
General and administrative expenses	General and administrative expense	83,318	1,631	(3)(4)	(84,949)
Restructuring costs		1,631	(1,631)	(3)	—
	Allowance for expected credit losses	—	—		—
(Gain) loss on sale of assets	Gain (loss) on natural gas and oil property and equipment	(1,090)	—	(5)	1,090
	Gain (loss) on sale of equity interest	—	—		—
	Unrealized gain (loss) on investment	—	—		—
Gain (loss) on commodity derivative instruments	Gain (loss) on derivative financial instruments	145,934	—	(4)	145,934
Impairment of oil and natural gas properties	Impairment of proved properties	66,785	—	(4)	(66,785)
	Operating profit (loss)	**317,931**	**(14,666)**		**332,597**
Interest expense	Finance costs	62,176	—	(4)	(62,176)
	Accretion of asset retirement obligation	—	14,666	(2)(4)	(14,666)
	Loss on early retirement of debt	—	—		—
Other income, net	Other income (expense)	(1,130)	—	(5)	1,130
	Income (loss) before taxation	**256,885**	**—**		**256,885**
Income tax expense (benefit)	Income tax benefit (expense)	604	—	(4)	(604)
	Net income (loss)	**256,281**	**—**		**256,281**
	Other comprehensive income (loss)	—	—		—
	Total comprehensive income (loss)	**$ 256,281**	**$ —**		**$ 256,281**

Notes:

(1) Represents the reclassification of amounts contained in "Oil revenues," "Natural gas revenues," "NGL revenues," and "Other revenues, net" on Maverick's historical income statement to "Revenue" to conform to the Company's income statement presentation.

(2) Represents the reclassification of amounts contained in "Depletion, depreciation and amortization" on Maverick's historical income statement to "Accretion of asset retirement obligation" to conform to the Company's income statement presentation.

(3) Represents the reclassification of amounts contained in "General and administrative expenses" and "Restructuring costs" on Maverick's historical income statement to "General and administrative expense" to conform to the Company's income statement presentation.

(4) Represents the presentation on Maverick's historical income statement as a negative value to conform to the Company's income statement presentation.

(5) Represents the presentation on Maverick's historical income statement as a positive value to conform to the Company's income statement presentation.

Note 3 - Oaktree Transaction Adjustments

The Unaudited Pro Forma Financial Information reflects the adjustments listed below for the Oaktree Transaction.

(a) Adjustments are for the period 1 April 2024 through 6 June 2024, the date the Oaktree Transaction closed and have been sourced from the unaudited historical financial records related to the Oaktree Assets. Note that the related Oaktree Assets adjustments for the period 1 January 2024 through 31 March 2024 are included within the ‘Oaktree Historical’ column of the pro forma condensed combined statement of operations for the six months ended June 30, 2024.

(b) Depletion expense associated with the acquired producing properties for the respective 6 and 12 month periods presented.

(c) Interest expense for the Company’s related $172 million borrowing on its Credit Facility and ABS Warehouse Facility using current interest rates, the issuance of an $83 million note payable to Oaktree and the assumption of Oaktree’s $133 million proportionate share of the ABS VI debt for the respective 6 and 12 month periods presented.

(d) Accretion of asset retirement obligation associated with Oaktree’s proportionate working interest in the asset retirement obligations for the respective 6 and 12 month periods presented.

(e) Adjustments to the income tax provision reflect the historical and adjusted income (loss) before taxation multiplied by an approximate 24% effective tax rate for the respective 6 and 12 month periods presented.

Note 4 - Acquisition Adjustments – including Maverick Preliminary Purchase Price Allocation

Statement of Financial Position

The table below calculates the ‘Acquisition Adjustments’ as presented on the face of the pro forma condensed combined statement of financial position. These adjustments are a combination of (i) Maverick US GAAP to IFRS adjustments (given that the starting column is the ‘Maverick As Adjusted’ US GAAP balance sheet as of June 30, 2024 as calculated in Note 2 and as presented on the face of the pro forma condensed combined statement of financial position); (ii) preliminary purchase price fair value adjustments; and (iii) other Maverick transaction related adjustments.

The sum of the ‘Maverick As Adjusted’ column and adjustments (1) through (4) reconciles to the ‘Preliminary Purchase Price Allocation’ column presented subsequently within this Note 4.

	Maverick As Adjusted	US GAAP to IFRS Adjustments	Purchase Fair Value Adjustments		Maverick Transaction Adjustments		Total Acquisition Adjustments
					(In thousands)		
ASSETS							
Non-current assets:							
Natural gas and oil properties, net	$ 1,579,386	$ —	$ (110,222)	(2)	$ —		$ (110,222)
Property, plant and equipment, net	74,209	—	—		—		—
Intangible assets	6,814	—	(6,698)	(3)	—		(6,698)
Derivative financial instruments	1,279	—	—		—		—
Other non-current assets	45,590	—	—		—		—
Total non-current assets	**1,707,278**	—	**(116,920)**		—		**(116,920)**
Current assets:							
Trade receivables, net	134,534	—	—		—		—
Cash and cash equivalents	62,662	—	—		207,100	(5)	207,100
					(207,100)	(5)	(207,100)
					(12,500)	(6)	(12,500)
Restricted cash	39,700	—	—		—		—
Derivative financial instruments	4,327	—	—		—		—
Other current assets	13,008	—	—		—		—
Total current assets	**254,231**	—	—		**(12,500)**		**(12,500)**
Total assets	**1,961,509**	—	**(116,920)**		**(12,500)**		**(129,420)**
EQUITY AND LIABILITIES							
Shareholders’ equity:							
Share capital	$ —	$ —	$ —		$ 5,305	(7)	$ 5,305
Share premium	—	—	—		346,274	(7)	346,274
Retained earnings (accumulated deficit)	588,425	—	—		(588,425)	(7)	(588,425)

						(49,945)	(8)	(49,945)
Equity attributable to owners of the parent	**588,425**	—		—		**(286,791)**		**(286,791)**
Total equity	**588,425**	—		—		**(286,791)**		**(286,791)**
Non-current liabilities:								
Asset retirement obligations	244,213	(68,809)	(1)	—		—		(68,809)
Leases	25,458	—		—		—		—
Borrowings	681,377	—		(21,553)	(4)	—		(21,553)
						207,100	(5)	207,100
						(12,500)	(6)	(12,500)
Derivative financial instruments	23,426	—		—		—		—
Other non-current liabilities	29,292	—		—		—		—
Total non-current liabilities	**1,003,766**	**(68,809)**		**(21,553)**		**194,600**		**104,238**
Current liabilities:								
Trade and other payables	225,051	—		—		—		—
Borrowings	113,544	—		(5,257)	(4)	—		(5,257)
Derivative financial instruments	22,579	—		—		—		—
Other current liabilities	8,144	8,445	(1)	—		—		8,445
						49,945	(8)	49,945
Total current liabilities	**369,318**	**8,445**		**(5,257)**		**49,945**		**53,133**
Total liabilities	**1,373,084**	**(60,364)**		**(26,810)**		**244,545**		**157,371**
Total equity and liabilities	$ **1,961,509**	$ **(60,364)**		$ **(26,810)**		$ **(42,246)**		**$ (129,420)**

Notes:

(1) Maverick prepares its financial statements in accordance with U.S. GAAP, while Diversified prepares its financial statements in accordance with IFRS. Accordingly, the Company has adjusted Maverick's current and non-current asset retirement obligation to conform to IFRS. No other material adjustments were necessary to conform to Diversified's IFRS presentation.

(2) Represents the downward adjustment of $110.2 million for the estimated fair value of Maverick's natural gas and oil properties at 30 June 2024.

(3) Represents the downward adjustment of $6.7 million for certain software intangibles that are not expected to be utilized by the combined company.

(4) Represents the downward adjustment of $21.6 million and $5.3 million, respectively, to Maverick's current and non-current ABS borrowings based on the estimated fair value at 30 June 2024.

(5) Represents the adjustment to cash and cash equivalents and non-current borrowings of $207.1 million for the expected cash consideration paid to legacy Maverick unitholders through a draw on the Company's expanded credit facility.

(6) Represents the adjustment of $12.5 million for estimated financing costs expected to be incurred by Diversified related to the amendment to be entered into by Diversified on the closing date of the Acquisition to increase the borrowing base and commitment amounts on its existing revolving credit facility.

(7) Represents the adjustment for the elimination of the legacy equity associated with Maverick, as well as the $351.6 million expected value of Diversified's shares to be issued to legacy Maverick unit holders based on Diversified's close price as of 6 February 2025. See calculation below.

(8) Represents the accrual of $33.8 million of estimated transaction costs and $16.2 million of estimated severance and change in control costs payable to certain identified Maverick officers who are expected to be terminated as a result of the Acquisition, which are expected to be incurred by Diversified subsequent to 30 June 2024. These transaction and severance and change in control costs are preliminary estimates; the final amounts and the resulting effect on Diversified's financial position may differ significantly.

Maverick preliminary purchase price allocation

As the accounting acquirer, Diversified expects to account for the Acquisition as a business combination in accordance with IFRS 3. Diversified's allocation of the preliminary purchase price with respect to the Acquisition is based on preliminary estimates of, and assumptions related to, the fair value of the assets to be acquired and liabilities to be assumed as of 30 June 2024, using currently available information. Because the Unaudited Pro Forma Financial Information has been prepared based on these preliminary estimates, the final purchase price allocation and the resulting effect on the financial position and results of operations of the combined company may be materially different from the pro forma amounts included herein. Diversified expects to finalize the purchase price allocation as soon as reasonably practicable after completing the Acquisition, which will not extend beyond the one-year measurement period provided under IFRS 3.

The preliminary purchase price allocation is subject to change due to several factors, including, but not limiting to, the following:

- Changes in the estimated fair value of Maverick's identifiable assets acquired and liabilities assumed as of the closing date of the Acquisition, which could result from changes in natural gas and oil commodity prices, oil and gas reserves estimates, discount rates and other factors; and

- Changes in the estimated fair value of the Diversified common stock consideration issued to Maverick unitholders, based on the Diversified common stock closing price. The final value of the consideration will be determined based on the market price of Diversified common stock at closing. A 20% change in the closing price of Diversified common stock, as compared to the 6 February 2025 closing price, would increase or decrease the consideration by approximately $70 million, assuming all other factors are held constant. Diversified anticipates that a change in the closing price of Diversified common stock will primarily impact the value of natural gas and oil properties.

The table below represents the preliminary value of the total consideration.

	Diversified Shares Issued[1]	**Price per Share**[2]	**Purchase Price Consideration**
	(In thousands, except share and per unit data)		
Diversified shares issued to legacy Maverick unit holders	21,217,713	$ 16.57	$ 351,578
PLUS: Cash consideration to Maverick through draw on expanded credit facility			207,100
Preliminary purchase price consideration			**$ 558,678**

Notes:

(1) The Diversified shares issued consists of the number of shares of Diversified common stock expected to be issued to legacy Maverick unitholders on the close date of the Acquisition.

(2) The per share price reflects the closing price per share of Diversified common stock as of 6 February 2025.

The table below represents the allocation of the preliminary price consideration to the net assets acquired. This 'Preliminary Purchase Price Allocation' column reconciles to the sum of the 'Maverick As Adjusted' column and adjustments (1) through (4) as set out within the first table within this Note 4.

	Preliminary Purchase Price Allocation
Assets acquired	*(In thousands)*
Non-current assets	
Natural gas and oil properties, net	$ 1,469,164
Property, plant and equipment, net	74,209
Intangible assets	116
Derivative financial instruments	1,279
Other non-current assets	45,590
Current assets	
Trade receivables, net	134,534
Cash and cash equivalents	62,662
Restricted cash	39,700
Derivative financial instruments	4,327
Other current assets	13,008
Total assets acquired	**1,844,589**
Liabilities assumed	
Non-current liabilities	
Asset retirement obligations	(175,404)

	Preliminary Purchase Price Allocation
Leases	(25,458)
Borrowings	(659,824)
Derivative financial instruments	(23,426)
Other non-current liabilities	(29,292)
Current liabilities	
Trade and other payables	(225,051)
Borrowings	(108,287)
Derivative financial instruments	(22,579)
Other current liabilities	(16,590)
Total liabilities assumed	**(1,285,911)**
Net assets acquired	**$ 558,678**
Preliminary purchase price consideration	**$ 558,678**

Statement of Operations

The unaudited pro forma combined statement of operations for the six months ended 30 June 2024 reflects the adjustments listed below for the Acquisition:

(a) Represents the incremental depreciation, depletion and amortization expense related to the assets to be acquired in the Acquisition, which is based on the preliminary purchase price allocation. Depletion was calculated using the unit-of-production method under the successful efforts method of accounting. The depletion expense was adjusted for the revision to the depletion rate reflecting the acquisition costs and the reserves volumes attributable to the acquired oil and gas properties. The pro forma depletion rate attributable to the Acquisition was $4.71 per barrel of oil equivalent.

(b) Represents the net increase to interest expense resulting from the (i) incremental interest expense for borrowings on Diversified's expanded credit facility to finance the closing of the Acquisition and (ii) incremental interest expense for the amortization of estimated financing costs related to the amendment to be entered into by Diversified on the closing date of the Acquisition to increase the borrowing base capacity and commitment amounts on Diversified's revolving credit facility as follows:

	Six Months Ended June 30 2024
	(In thousands)
Incremental interest expense for borrowings on Diversified's expanded revolving credit facility	(9,077)
Incremental interest expense for amortization of expected financing costs	(1,563)
Net transaction accounting adjustments to interest expense	**$ (10,640)**

A 0.125% change in the variable interest rate of Diversified's revolving credit facility or a $10 million change in the amount financed would increase or decrease interest expense presented in the unaudited pro forma condensed combined statement of operations for the six months ended 30 June 2024 by $0.1 million and $0.4 million, respectively.

(c) Represents a decrease in accretion expense attributable to asset retirement obligations of $1.1 million for the six months ended 30 June 2024 due to a downward adjustment in the asset retirement obligation based on its fair value under IFRS.

(d) Represents the estimated income tax impact of the pro forma adjustments from the Acquisition at the estimated blended federal and state statutory rate of approximately 24% for the six months ended 30 June 2024. Because the tax rates used for this Unaudited Pro Forma Financial Information are an estimate, the blended rate will likely vary from the actual effective rate in periods subsequent to the completion of the Acquisition.

(e) The table below represents the calculation of the weighted average shares outstanding and earnings per share included in the unaudited pro forma condensed combined statement of operations for the six months ended 30 June 2024. As the Acquisition is being reflected in the unaudited pro forma condensed combined statement of operations for the six months ended 30 June 2024 as if it had occurred on 1 January 2025, the calculation of weighted average shares outstanding for basic and diluted earnings per share assumes that the shares issuable related to the Acquisition have been outstanding for the entire period.

	Six Months Ended June 30, 2024
	(In thousands, except share and per unit data)
Net loss, pro forma combined	**$ (51,308)**
Diversified weighted average shares outstanding - basic	47,202,283
Diversified shares issued in exchange for legacy Maverick shares as part of consideration transferred	21,217,713
Pro forma weighted average shares outstanding - basic	**68,419,996**
Dilutive impact of potential shares	0
Pro forma weighted average shares outstanding - diluted	**68,419,996**
Earnings attributable to Diversified per share, basic	$ (0.75)
Earnings attributable to Diversified per share, diluted	$ (0.75)
Potentially dilutive shares[(1)]	359,016

Note:

(1) Outstanding share-based payment awards excluded from the diluted EPS calculation because their effect would have been anti-dilutive.

The unaudited pro forma condensed combined statement of operations for the year ended 31 December 2023 reflects the adjustments listed below.

(a) Represents the incremental depreciation, depletion and amortization expense related to the assets to be acquired in the Acquisition, which is based on the preliminary purchase price allocation. Depletion was calculated using the unit-of-production method under the successful efforts method of accounting. The depletion expense was adjusted for the revision to the depletion rate reflecting the acquisition costs and the reserves volumes attributable to the acquired oil and gas properties. The pro forma depletion rate attributable to the Acquisition was $4.71 per barrel of oil equivalent.

(b) Represents $33.8 million of estimated transaction costs and $16.2 million of estimated severance and change in control costs payable to certain Maverick officers who are expected to be terminated as a result of the Acquisition, which are expected to be incurred by Diversified upon closing the Acquisition. These costs are preliminary estimates; the final amounts and the resulting effect on Diversified's results of operations may differ significantly. These costs are nonrecurring and will not affect Diversified's statement of operations beyond 12 months after the closing of the Acquisition.

(c) Represents the net increase to interest expense resulting from the (i) incremental interest expense for borrowings on Diversified's expanded credit facility to finance the closing of the Acquisition and (ii) incremental interest expense for the amortization of estimated financing costs related to the amendment to be entered into by Diversified on the closing date of the Acquisition to increase the borrowing base capacity and commitment amounts on Diversified's revolving credit facility as follows:

	Year Ended December 31, 2023
	(In thousands)
Incremental interest expense for borrowings on Diversified's expanded revolving credit facility	(17,622)
Incremental interest expense for amortization of expected financing costs	(3,125)
Net transaction accounting adjustments to interest expense	**$ (20,747)**

A 0.125% change in the variable interest rate of Diversified's revolving credit facility or a $10 million change in the amount financed would increase or decrease interest expense presented in the unaudited pro forma condensed combined statement of operations for the year ended December 31, 2023 by $0.3 million and $0.9 million, respectively.

(d) Represents a decrease in accretion expense attributable to asset retirement obligations of $3.2 million for the year ended 31 December 2023 due to a downward adjustment in the asset retirement obligation based on its fair value under IFRS.

(e) Represents the estimated income tax impact of the pro forma adjustments from the Acquisition at the estimated blended federal and state statutory rate of approximately 24% for the year ended 31 December 2023. Because the tax rates used for this Unaudited Pro Forma Financial Information are an estimate, the blended rate will likely vary from the actual effective rate in periods subsequent to the completion of the Acquisition.

(f) The table below represents the calculation of the weighted average shares outstanding and earnings per share included in the unaudited pro forma condensed combined statement of operations for the year ended 31 December 2023. As the Acquisition is being reflected in the unaudited pro forma condensed combined statement of operations for the year ended 31 December 2023 as if it had occurred on 1 January 2025, the calculation of weighted average shares outstanding for basic and diluted earnings per share assumes that the shares issuable related to the Acquisition have been outstanding for the entire year.

	Year Ended December 31, 2023
	(In thousands, except share and per unit data)
Net income, pro forma combined	**$ 957,579**
Diversified weighted average shares outstanding - basic	47,165,380
Diversified shares issued in exchange for legacy Maverick shares as part of consideration transferred	21,217,713
Pro forma weighted average shares outstanding - basic	**68,383,093**
Dilutive impact of potential shares	349,141
Pro forma weighted average shares outstanding - diluted	**68,732,234**
Earnings attributable to Diversified per share, basic	$ 14.00
Earnings attributable to Diversified per share, diluted	$ 13.93
Potentially dilutive shares[1]	54,133

Note:

(1) Outstanding share-based payment awards excluded from the diluted EPS calculation because their effect would have been anti-dilutive.

The directors (the "**Directors**")
Diversified Energy Company Plc
4th Floor, Phoenix House
1 Station Hill, Reading
Berkshire, RG1 1NB
United Kingdom

Stifel Nicolaus Europe Limited (the "**Sponsor**")
150 Cheapside
London, EC2V 6ET
United Kingdom

20 February 2025

Dear Ladies and Gentlemen

Diversified Energy Company Plc (the "Company")

We report on the unaudited pro forma financial information (the "**Pro Forma Financial Information**") set out in Section A of Part 4 of the Company's prospectus dated 20 February 2025 (the **"Prospectus"**).

This report is required by section 3 of Annex 20 to the PR Regulation and item 11.5 of Annex 3 to the PR Regulation and is given for the purpose of complying with that item and for no other purpose.

Opinion

In our opinion:

(a) the Pro Forma Financial Information has been properly compiled on the basis stated; and
(b) such basis is consistent with the accounting policies of the Company.

Responsibilities

It is the responsibility of the Directors to prepare the Pro Forma Financial Information in accordance with sections 1 and 2 of Annex 20 to the PR Regulation and item 11.5 of Annex 3 to the PR Regulation.

It is our responsibility to form an opinion, as required by section 3 of Annex 20 of the PR Regulation and item 11.5 of Annex 3 to the PR Regulation, as to the proper compilation of the Pro Forma Financial Information and to report our opinion to you.

No reports or opinions have been made by us on any financial information relating to the year ended 31 December 2023 and the six month period ended 30 June 2024 for Maverick Natural Resources LLC ("**Maverick**" and, together with its subsidiaries, the "**Maverick Group**") or for the Oaktree Assets (on 6 June 2024, the Company acquired Oaktree Capital Management, LP's 100% membership interest in OCM Denali Holdings, LLC and its subsidiaries, whose assets predominantly included non-operated working interests in producing wells and related facilities (the "**Oaktree Assets**")) used in the compilation of the Pro Forma Financial Information. In providing this opinion we are not

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providing any assurance on any source financial information of the Maverick Group or the Oaktree Assets, on which the Pro Forma Financial Information is based beyond the above opinion.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed at the date of their issue.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and for any responsibility arising under item 5.3.2R(2)(f) of the Prospectus Regulation Rules of the Financial Conduct Authority (the "**Prospectus Regulation Rules**") to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 3 to the PR Regulation, consenting to its inclusion in the Prospectus.

Basis of preparation

The Pro Forma Financial Information has been prepared on the basis described in the notes to the Pro Forma Financial Information, for illustrative purposes only, to provide information about how the proposed admission of the new ordinary shares of the Company to the equity shares (commercial companies) category of the Official List maintained by the Financial Conduct Authority and the proposed admission of those shares to trading on the London Stock Exchange's main market for listed securities, and the proposed acquisition by the Company of the Maverick Group (the "**Transaction**"), might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the financial statements for the year ended 31 December 2023 and period ended 30 June 2024.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Financial Reporting Council ("**FRC**") in the United Kingdom. We are independent in accordance with the Revised Ethical Standard 2024 issued by the FRC as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro Forma Financial Information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Declaration

For the purposes of item 5.3.2 R (2)(f) of the Prospectus Regulation Rules we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 3 to the PR Regulation.

Yours faithfully

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants

ESTIMATES

of

RESERVES AND FUTURE REVENUE

to the

MAVERICK NATURAL RESOURCES, LLC INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in the

UNITED STATES

as of

JANUARY 1, 2025

COMPETENT PERSON'S REPORT

Prepared for and

BASED ON PRICE AND COST PARAMETERS

specified by

DIVERSIFIED ENERGY COMPANY PLC

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY

GEOPHYSICS • PETROPHYSICS

February 20, 2025

Diversified Energy Company PLC
1800 Corporate Drive
Birmingham, Alabama 35242

Stifel Nicolaus Europe Limited
150 Cheapside
London EC2V 6ET
United Kingdom

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of January 1, 2025, to the Maverick Natural Resources, LLC (Maverick) interest in certain oil and gas properties located in the United States. It is our understanding that Diversified Energy Company PLC (DEC) has entered into an agreement to purchase the Maverick interest in these properties, with an expected closing date in the first half of 2025. We completed our evaluation on or about the date of this letter. This Competent Person's Report (report) has been prepared using price and cost parameters specified by DEC, referred to as the Base Price Case, as discussed in subsequent paragraphs of this letter.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE), the United Kingdom (UK) version of Regulation (EU) 2017/1129 that forms part of UK law by virtue of the European Union (Withdrawal) Act 2018 as amended, and the recommendations of the Financial Conduct Authority (FCA), as set out in Primary Market Technical Note 619.1 – the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification for the primary evaluators who contributed to this report and a glossary of terms used in this report. This report has been prepared for use by DEC in connection with a prospectus to be published for admission of the ordinary shares proposed to be issued by DEC in connection with the acquisition of Maverick and a potential equity raise to the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange's Main Market for listed securities. In our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Maverick interest in these properties, as of January 1, 2025, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	62,430.6	51,062.5	545,909.7	2,341,147.1	1,518,466.8
Proved Developed Non-Producing	566.7	48.0	557.2	20,136.5	11,536.6
Proved Undeveloped	31,591.5	5,886.2	166,862.4	1,146,707.5	454,593.6
Total Proved	94,588.9	56,996.7	713,329.3	3,507,990.0	1,984,597.2

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

As shown in the Table of Contents, this report includes summary projections of reserves and revenue by reserves category for the Base Price Case, a technical discussion, and pertinent figures and exhibits.

Gross revenue shown in this report is Maverick's share of the gross (100 percent) revenue from the properties prior to any deductions and, as requested, includes the revenue associated with the sale of sulfur; the revenue attributable to sulfur is shown herein as "other" revenue. Future net revenue is after deductions for Maverick's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using Base Price Case oil, NGL, gas, and sulfur price parameters specified by DEC. Oil and NGL prices are based on NYMEX West Texas Intermediate prices and are adjusted for quality, transportation fees, and market differentials. Gas prices are based on NYMEX Henry Hub prices and are adjusted for energy content, transportation fees, and market differentials. The sulfur price is $116 per metric ton. Sensitivities using Low and High Price Cases are further detailed in the Technical Discussion section of this report. Oil, NGL, and gas prices, before adjustments, are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2025	69.87	3.527
12-31-2026	66.70	3.907
12-31-2027	64.88	3.841
12-31-2028	63.81	3.729
Thereafter	63.07	3.584

Operating costs used in this report are based on operating expense records of Maverick. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. As requested, the per-well costs for the operated properties include credits to operating expenses associated with overhead recovery allowed under joint operating agreements; however, these credits have not been used to determine economic limits for the properties. The current overhead recovery amount is less than 5 percent of the first-year estimated operating costs for the proved developed producing category. Headquarters general and administrative overhead expenses are included to the extent that they are covered under joint operating agreements for the operated properties. As requested, operating costs are not escalated for inflation.

Capital costs used in this report were provided by Maverick and are based on internal planning budgets. Capital costs are included as required for facility and field maintenance, workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Maverick's estimates of the costs to abandon the wells and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Maverick interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Maverick receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Maverick, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from DEC, Maverick, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: C. Ashley Smith
C. Ashley Smith, P.E. 100560
Vice President

Date Signed: February 20, 2025

STATE OF TEXAS
C. A. SMITH
100560
LICENSED
PROFESSIONAL ENGINEER

By: Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: February 20, 2025

STATE OF TEXAS
E. C. ROY, III
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CAS:MSS

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

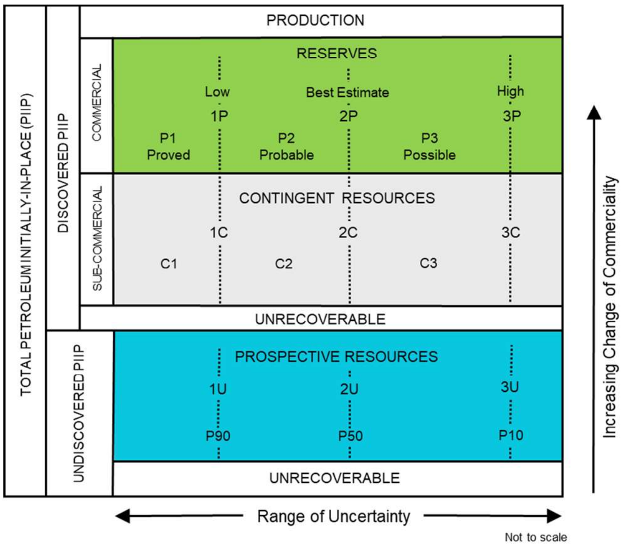

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **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 project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. 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 categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **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.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

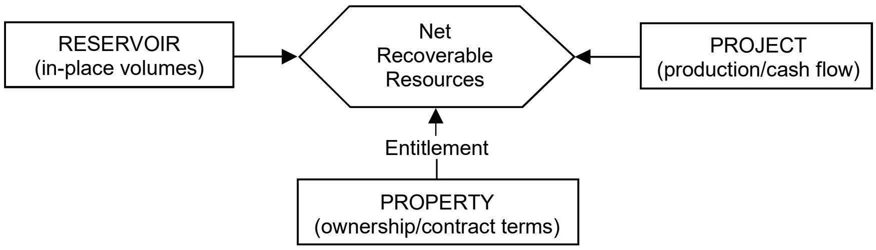

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.
2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CERTIFICATE OF QUALIFICATION

I, C. Ashley Smith, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

> I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for Diversified Energy Company PLC. The effective date of this evaluation is January 1, 2025.
>
> I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Diversified Energy Company PLC or its affiliated companies.
>
> I attended University of Missouri-Rolla, and I graduated in 2000 with a Bachelor of Science Degree in Petroleum Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 23 years of experience in petroleum engineering studies and evaluations.

By: C. Ashley Smith

C. Ashley Smith, P.E.
Vice President
Texas License No. 100560

STATE OF TEXAS
C. A. SMITH
100560
LICENSED
PROFESSIONAL ENGINEER

February 20, 2025
Houston, Texas

CERTIFICATE OF QUALIFICATION

I, Edward C. Roy III, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

> I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for Diversified Energy Company PLC. The effective date of this evaluation is January 1, 2025.
>
> I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Diversified Energy Company PLC or its affiliated companies.
>
> I attended Texas Christian University, and I graduated in 1992 with a Bachelor of Science Degree in Geology; I attended Texas A&M University and graduated in 1998 with a Master of Science Degree in Geology; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 27 years of experience in geological and geophysical studies and evaluations.

By: Edward C. Roy III

Edward C. Roy III, P.G.
Vice President
Texas License No. 2364

STATE OF TEXAS
E. C. ROY, III
GEOLOGY
2364
LICENSED
PROFESSIONAL GEOSCIENTIST

February 20, 2025
Houston, Texas

GLOSSARY OF TERMS

$	United States dollars
%	percent
Abandon	The process of decommissioning a wellbore that is no longer useful for production or injection.
As-of date	Pertaining to an assessment or evaluation report; the date for which the assessment or evaluation is valid with respect to data (production and other data) and product pricing.
API	American Petroleum Institute
b-factor	hyperbolic b-factor
Barrel	A unit of measurement commonly used in quoting volumes of liquid hydrocarbons; 1 barrel is equivalent to 42 United States gallons.
BBL	barrels
BBL/MMCF	barrels per million cubic feet
BOE	barrels of oil equivalent
BTU	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit under specific conditions.
CO_2	carbon dioxide
Commercial	When a project is commercial, this implies that the essential social, environmental, and economic conditions are met, including political, legal, regulatory, and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame.
DCA	decline curve analysis
DCP	DCP Midstream Partners
DEC	Diversified Energy Company PLC
Energy Transfer	Energy Transfer LP
EU	European Union
Evaluation	The geoscience, petrophysical, engineering, and associated studies conducted on a petroleum exploration, development, or producing project resulting in estimates of in-place volumes of petroleum and the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines.
FCA	Financial Conduct Authority
Formation	A body of rock that is sufficiently distinctive and continuous that it can be mapped.
ft	feet
frac	Large hydraulic stimulation treatments required to maximize the flow of hydrocarbons from the reservoir to the wellbore.

GLOSSARY OF TERMS

Geology	The study of the earth and the physical, chemical, and biological processes affecting it.
Geophysics	The study of rock properties and stratigraphy through the use of analytical methods involving various types of remote sensing data collection and interpretation.
Gross production	100 percent of oil and gas production.
Gross wells	Total wells in which an interest is owned.
H_2S	hydrogen sulfide
Horizontal well	An oil or gas well that is drilled at an angle of at least eighty degrees to a vertical wellbore.
Hydrocarbon	Chemical compounds consisting wholly of hydrogen and carbon, in either liquid or gaseous form. Natural gas and petroleum are mixtures of hydrocarbons.
M$	thousands of United States dollars
Maverick	Maverick Natural Resources, LLC
MarkWest	MarkWest Energy Partners, L.P.
MBBL	thousands of barrels
MBOE	thousands of barrels of oil equivalent
MCF	thousands of cubic feet
MMBTU	millions of British thermal units
MMCF	millions of cubic feet
N_2	nitrogen
Net production	That portion of gross production attributable to an entity's owned net revenue interest.
Net revenue interest	An entity's ownership relative to oil and gas production and revenue.
NGL	natural gas liquids
NSAI	Netherland, Sewell & Associates, Inc.
NYMEX	New York Mercantile Exchange
Overhead	The ongoing expense of operating a business.
Perforate	To create holes in a production casing or liner to allow fluids to flow from the reservoir into the wellbore.
Permeability	A measure of the ability of fluid to flow through a given rock.
Petrophysics	A set of models and computer algorithms that use data from well logs and cores to estimate the physical characteristics of rocks such as shale volume, porosity, water saturation, and permeability.
Pipeline	A pipe through which any hydrocarbon or its products is delivered to an end user.
Plains	Plains All American Pipeline

GLOSSARY OF TERMS

Porosity	A measure of the amount of void spaces or pores in a given rock or material that can store trapped fluids.
Possible reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than probable reserves.
PRMS	Petroleum Resources Management System
Probable reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.
Proved developed	Proved developed producing and proved developed non-producing.
Proved reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.
Proved undeveloped reserves	Proved reserves that are expected to be recovered through future significant investments.
report	Competent Person's Report
Reserves	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.
Reservoir	A porous rock unit in which hydrocarbons occur.
Sandstone	A sedimentary rock composed mainly of sand-size mineral or rock grains and often composed largely of grains of quartz.
Sediment	Generally, waterborne debris that settles out of suspension.
Sedimentary rock	A type of rock formed by aggregation of sediments.
Shale	A fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers.
Silt	Similar to a sandstone but with finer grain size.
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
Stratigraphy	The study of the history, composition, relative ages, and distribution of strata, and the interpretation of strata to elucidate Earth history.
UK	United Kingdom
Undeveloped acreage	Acreage in which wells have not been drilled or completed to a point that would permit the production of commercial quantities of hydrocarbons.
Valero	Valero Energy Corporation
Vertical well	An oil or gas well that is drilled vertically into the ground.
Well log	A device that records physical parameters of rock in the wellbore during or after drilling, or the data obtained by these devices.

GLOSSARY OF TERMS

Wellhead	The portion of a well that is above ground; includes the casinghead and tubing head. It is used to contain the pressure in the tubing or tubing-casing annulus, land tubing, control the flow of fluids and reduce the pressure, and run tools.
Williams	The Williams Company, Inc.
Working interest	An entity's ownership relative to cost and expenses.
WTI	West Texas Intermediate

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

TOTAL PROVED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	22,675.5	254,177.7	7,307.3	4,412.2	51,249.4	67.77	18.08	3.252	495,217.9	79,756.2	166,639.2	594.2	742,207.5
12-31-2026	25,765.7	257,760.9	9,317.8	4,414.9	53,499.3	64.92	17.21	3.643	604,957.1	76,002.5	194,921.7	531.0	876,412.3
12-31-2027	22,842.9	239,715.7	9,225.0	4,211.2	52,144.9	63.06	16.62	3.574	581,736.5	69,977.7	186,343.8	458.0	838,516.1
12-31-2028	21,099.4	236,531.2	7,959.8	3,906.0	51,353.3	61.87	16.35	3.503	492,450.6	63,844.9	179,902.7	422.1	736,620.4
12-31-2029	19,204.7	221,120.4	6,755.4	3,477.9	47,366.9	61.04	16.17	3.423	412,373.1	56,228.9	162,131.3	355.8	631,089.1
12-31-2030	14,596.8	195,926.3	5,365.8	3,118.5	41,566.0	60.88	16.18	3.419	326,697.0	50,445.0	142,107.2	313.2	519,562.4
12-31-2031	11,603.1	166,397.8	4,528.8	2,833.3	36,003.9	60.76	16.18	3.377	275,151.6	45,843.7	121,580.3	284.3	442,860.0
12-31-2032	9,962.3	146,240.1	3,992.5	2,592.8	32,115.1	60.66	16.18	3.354	242,197.1	41,959.3	107,717.2	264.4	392,138.1
12-31-2033	8,742.4	129,535.3	3,568.2	2,379.2	29,018.7	60.58	16.18	3.340	216,148.2	38,497.4	96,934.2	240.4	351,820.2
12-31-2034	7,797.0	116,255.6	3,221.8	2,189.4	26,460.5	60.51	16.18	3.332	194,946.3	35,420.1	88,161.1	213.9	318,741.3
12-31-2035	7,079.0	105,850.7	2,946.4	2,024.4	24,293.8	60.45	16.17	3.327	178,107.6	32,740.5	80,817.1	199.9	291,865.2
12-31-2036	6,299.9	93,413.3	2,702.6	1,875.8	22,381.8	60.40	16.17	3.323	163,240.7	30,326.8	74,366.4	187.7	268,121.5
12-31-2037	5,678.7	83,926.8	2,472.8	1,737.1	20,657.5	60.36	16.16	3.320	149,260.0	28,068.9	68,588.7	170.3	246,087.8
12-31-2038	5,191.2	77,055.4	2,256.1	1,607.4	19,098.7	60.35	16.15	3.320	136,157.3	25,966.9	63,408.6	158.7	225,691.6
12-31-2039	4,622.7	68,526.0	1,960.0	1,473.0	17,707.3	60.16	16.05	3.321	117,910.2	23,645.5	58,806.9	0.0	200,362.6
SUBTOTAL	193,161.3	2,392,433.4	73,580.3	42,253.2	524,916.9	62.33	16.54	3.415	4,586,550.8	698,724.2	1,792,426.5	4,394.0	7,082,096.1
REMAINING	48,882.2	684,566.3	21,008.5	14,743.5	188,412.4	59.59	15.99	3.370	1,251,805.6	235,751.9	634,872.2	0.0	2,122,429.8
TOTAL	242,043.5	3,076,999.7	94,588.9	56,996.7	713,329.3	61.72	16.40	3.403	5,838,356.5	934,476.1	2,427,298.8	4,394.0	9,204,526.1
CUM PROD	776,113.0	12,362,356.0											
ULTIMATE	1,018,156.0	15,439,354.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	6,037	2,755.5	37,230.3	10,658.8	161,998.0	8,318.2	233,753.5	290,247.7	290,247.7	276,709.0
12-31-2026	6,008	2,824.5	45,150.6	12,567.0	354,792.0	8,260.9	234,252.8	221,389.0	511,636.7	463,836.0
12-31-2027	5,359	2,624.1	41,607.4	13,268.6	206,304.2	8,260.9	224,311.9	344,763.3	856,400.0	734,674.3
12-31-2028	5,163	2,481.0	35,865.8	11,113.6	145,343.6	8,260.9	206,685.9	329,350.6	1,185,750.5	970,369.2
12-31-2029	4,922	2,309.8	30,765.6	8,964.6	87,494.8	7,585.9	184,972.0	311,306.5	1,497,057.0	1,172,735.5
12-31-2030	4,667	2,232.9	25,025.9	7,736.9	14,476.2	7,510.9	167,418.0	297,394.2	1,794,451.2	1,349,243.3
12-31-2031	4,492	2,161.3	21,201.4	6,928.9	13,667.9	8,339.1	153,735.6	238,986.7	2,033,438.0	1,478,104.6
12-31-2032	4,318	2,089.6	18,701.3	6,310.3	12,988.4	7,466.8	142,598.3	204,072.9	2,237,510.9	1,578,113.2
12-31-2033	4,145	2,019.0	16,741.9	5,769.6	12,311.5	7,475.2	131,888.5	177,633.6	2,415,144.4	1,657,241.1
12-31-2034	3,939	1,922.5	15,149.4	5,292.7	11,560.9	8,169.6	122,436.7	156,132.3	2,571,276.8	1,720,463.7
12-31-2035	3,812	1,859.6	13,837.5	4,912.6	11,024.9	7,408.2	115,107.1	139,575.0	2,710,851.8	1,771,841.3
12-31-2036	3,668	1,853.2	12,676.9	4,562.7	10,534.3	7,192.0	108,147.6	125,007.7	2,835,859.5	1,813,672.1
12-31-2037	3,444	1,764.7	11,625.0	4,216.0	10,055.1	7,191.3	100,890.4	112,110.0	2,947,969.5	1,847,776.0
12-31-2038	3,311	1,682.7	10,675.6	3,871.8	8,469.6	11,118.9	93,512.0	98,043.5	3,046,013.2	1,874,891.0
12-31-2039	3,165	1,569.5	9,574.2	3,348.4	8,052.9	17,195.7	83,266.4	78,925.1	3,124,938.2	1,894,735.9
SUBTOTAL			345,828.9	109,522.4	1,069,073.9	129,754.4	2,302,976.5	3,124,938.2	3,124,938.2	1,894,735.9
REMAINING			101,426.2	37,717.1	133,480.4	448,130.8	1,018,623.3	383,052.0	3,507,990.0	1,984,597.2
TOTAL OF 50.0 YRS			447,255.1	147,239.5	1,202,554.4	577,885.2	3,321,599.7	3,507,990.3	3,507,990.0	1,984,597.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	2,194,060.3
12.000	1,809,727.5
15.000	1,596,846.3
20.000	1,333,615.6
25.000	1,144,456.2
30.000	1,002,494.7
35.000	892,363.6
40.000	804,676.7
45.000	733,372.5
50.000	674,375.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
BASE PRICE CASE

Table I

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED PRODUCING RESERVES

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	18,497.2	238,883.2	6,354.2	4,372.0	48,719.7	67.66	18.05	3.208	429,924.4	78,921.4	156,271.1	594.2	665,711.1
12-31-2026	13,674.1	205,175.5	5,192.9	3,954.8	42,435.9	64.29	17.23	3.541	333,862.9	68,161.2	150,282.9	531.0	552,838.1
12-31-2027	11,271.7	180,690.1	4,519.1	3,592.1	37,978.3	62.36	16.75	3.457	281,792.9	60,173.9	131,276.6	458.0	473,701.5
12-31-2028	9,872.1	160,493.6	4,039.2	3,263.9	34,184.9	61.20	16.49	3.340	247,188.6	53,820.6	114,167.4	422.1	415,598.8
12-31-2029	8,779.3	142,785.8	3,627.8	2,964.4	30,975.7	60.36	16.31	3.192	218,957.5	48,349.6	98,877.1	355.8	366,540.0
12-31-2030	7,671.6	128,852.1	3,300.0	2,736.3	28,485.3	60.27	16.30	3.188	198,907.1	44,608.5	90,813.5	313.2	334,642.4
12-31-2031	6,982.0	117,597.3	3,029.2	2,528.6	26,256.2	60.21	16.30	3.186	182,385.0	41,210.1	83,656.8	284.3	307,536.2
12-31-2032	6,366.2	107,406.4	2,792.8	2,338.2	24,259.9	60.15	16.29	3.185	167,986.7	38,099.4	77,279.2	264.4	283,629.8
12-31-2033	5,777.4	97,125.3	2,565.7	2,160.0	22,413.0	60.08	16.29	3.186	154,138.4	35,182.7	71,400.2	240.4	260,961.6
12-31-2034	5,270.1	88,385.6	2,360.3	1,996.7	20,750.5	60.02	16.28	3.187	141,667.5	32,511.2	66,125.2	213.9	240,517.8
12-31-2035	4,873.8	81,364.3	2,191.3	1,852.2	19,258.1	59.97	16.28	3.189	131,408.8	30,146.2	61,407.3	199.9	223,162.3
12-31-2036	4,343.3	71,559.0	2,031.0	1,720.2	17,874.6	59.93	16.27	3.189	121,709.2	27,984.1	57,009.6	187.7	206,890.6
12-31-2037	3,920.6	64,182.4	1,868.6	1,595.0	16,576.3	59.88	16.26	3.190	111,900.0	25,932.2	52,883.8	170.3	190,886.3
12-31-2038	3,596.0	59,044.8	1,707.8	1,476.7	15,369.8	59.88	16.26	3.192	102,256.7	24,005.1	49,067.0	158.7	175,487.5
12-31-2039	3,164.0	51,970.4	1,459.2	1,352.4	14,276.5	59.59	16.15	3.195	86,949.2	21,837.7	45,615.2	0.0	154,402.1
SUBTOTAL	114,059.7	1,795,515.5	47,039.0	37,903.6	399,814.7	61.89	16.65	3.267	2,911,035.1	630,944.1	1,306,133.0	4,394.0	4,852,506.6
REMAINING	31,939.6	482,672.9	15,391.6	13,159.0	146,095.1	58.75	16.13	3.236	904,252.5	212,304.4	472,834.3	0.0	1,589,391.0
TOTAL	145,999.4	2,278,188.5	62,430.6	51,062.5	545,909.7	61.11	16.51	3.259	3,815,287.6	843,248.4	1,778,967.3	4,394.0	6,441,897.5
CUM PROD	776,092.9	12,360,285.0											
ULTIMATE	922,092.2	14,638,473.0											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS AND EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	5,989	2,759.8	32,119.7	10,325.0	20,289.2	8,318.2	227,082.0	367,576.0	367,576.0	351,491.2
12-31-2026	5,876	2,744.0	25,885.5	9,227.1	19,119.0	8,260.9	201,088.6	289,256.9	656,832.9	602,678.0
12-31-2027	5,174	2,452.2	22,065.3	8,125.3	17,763.4	8,260.9	181,693.7	235,793.2	892,626.0	788,769.8
12-31-2028	4,922	2,334.1	19,340.2	7,280.5	16,520.4	8,260.9	166,017.1	198,179.6	1,090,805.8	930,942.1
12-31-2029	4,633	2,191.4	17,111.8	6,497.2	15,447.8	7,585.9	151,019.9	168,877.6	1,259,683.5	1,041,072.7
12-31-2030	4,376	2,131.2	15,598.5	6,008.3	14,392.0	7,510.9	140,015.0	151,117.4	1,410,800.9	1,130,657.9
12-31-2031	4,201	2,050.2	14,317.1	5,587.0	13,667.9	8,339.1	130,776.6	134,848.1	1,545,649.0	1,203,329.5
12-31-2032	4,027	1,978.6	13,181.3	5,212.4	12,988.4	7,466.8	122,564.0	122,216.7	1,667,865.7	1,263,205.4
12-31-2033	3,854	1,910.6	12,119.5	4,843.8	12,311.5	7,466.8	113,937.4	110,282.9	1,778,148.6	1,312,322.3
12-31-2034	3,650	1,816.0	11,171.1	4,492.1	11,560.9	8,169.6	106,024.4	99,099.8	1,877,248.5	1,352,446.5
12-31-2035	3,523	1,754.6	10,345.0	4,207.1	11,024.9	7,408.2	99,863.6	90,313.6	1,967,562.1	1,385,688.8
12-31-2036	3,379	1,757.3	9,566.1	3,932.4	10,534.3	7,192.0	93,839.6	81,825.9	2,049,388.0	1,413,069.3
12-31-2037	3,155	1,672.6	8,822.6	3,646.6	10,055.1	7,191.3	87,349.0	73,821.8	2,123,209.9	1,435,526.3
12-31-2038	3,022	1,591.2	8,129.0	3,353.1	8,469.6	11,050.1	80,617.3	63,868.3	2,187,078.1	1,453,190.5
12-31-2039	2,877	1,477.9	7,244.8	2,873.0	8,052.9	17,195.7	70,933.0	48,102.7	2,235,180.8	1,465,287.6
SUBTOTAL			227,017.4	85,610.9	202,197.1	129,677.3	1,972,821.5	2,235,180.8	2,235,180.8	1,465,287.6
REMAINING			74,711.1	32,438.3	133,480.4	440,639.0	802,156.8	105,965.7	2,341,147.1	1,518,466.8
TOTAL OF 50.0 YRS			301,728.4	118,049.2	335,677.6	570,316.3	2,774,978.3	2,341,146.6	2,341,147.1	1,518,466.8

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	1,647,378.2
12.000	1,409,612.7
15.000	1,275,815.3
20.000	1,108,353.5
25.000	986,189.2
30.000	893,016.2
35.000	819,471.7
40.000	759,841.6
45.000	710,435.1
50.000	668,772.6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
BASE PRICE CASE

Table II

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED NON-PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	954.3	1,207.9	91.1	10.7	81.5	66.61	20.17	2.577	6,069.5	215.4	210.1	0.0	6,495.0
12-31-2026	479.4	703.9	65.1	7.1	55.7	60.82	18.94	3.032	3,960.1	133.8	169.0	0.0	4,262.9
12-31-2027	301.9	445.0	47.0	4.6	36.1	57.93	18.38	2.975	2,719.8	84.4	107.5	0.0	2,911.6
12-31-2028	221.4	324.2	36.7	3.4	27.1	56.06	18.02	2.874	2,056.1	62.0	78.0	0.0	2,196.1
12-31-2029	175.2	254.3	30.7	2.8	21.9	54.87	17.77	2.740	1,684.2	49.1	59.9	0.0	1,793.2
12-31-2030	145.5	247.4	26.7	2.3	32.3	54.60	17.73	3.340	1,460.4	41.1	107.9	0.0	1,609.4
12-31-2031	124.2	212.5	23.7	2.0	28.7	54.41	17.69	3.366	1,288.5	35.5	96.7	0.0	1,420.7
12-31-2032	108.4	186.2	21.3	1.8	25.9	54.27	17.66	3.384	1,154.9	31.3	87.7	0.0	1,273.9
12-31-2033	95.2	164.5	18.7	1.5	22.7	53.88	17.69	3.402	1,006.9	27.2	77.1	0.0	1,111.2
12-31-2034	85.2	147.6	16.9	1.4	19.7	53.69	17.69	3.385	908.7	24.4	66.8	0.0	999.8
12-31-2035	77.4	133.8	15.6	1.3	18.2	53.63	17.66	3.393	838.2	22.3	61.7	0.0	922.2
12-31-2036	70.8	122.2	14.5	1.2	16.8	53.57	17.64	3.398	776.9	20.5	57.2	0.0	854.6
12-31-2037	65.3	112.1	13.5	1.1	15.7	53.53	17.62	3.402	724.7	19.1	53.3	0.0	797.1
12-31-2038	60.3	101.5	12.6	0.9	13.6	53.41	17.79	3.433	670.9	15.5	46.6	0.0	733.0
12-31-2039	55.7	88.8	11.4	0.4	9.9	53.13	18.92	3.548	607.7	8.4	35.1	0.0	651.2
SUBTOTAL	3,020.1	4,452.0	445.5	42.4	425.9	58.19	18.64	3.087	25,927.5	789.9	1,314.5	0.0	28,032.0
REMAINING	649.8	1,082.2	121.2	5.6	131.4	55.37	18.92	3.617	6,708.5	105.6	475.1	0.0	7,289.2
TOTAL	3,669.9	5,534.2	566.7	48.0	557.2	57.59	18.67	3.212	32,636.1	895.5	1,789.6	0.0	35,321.2
CUM PROD	20.1	2,071.0											
ULTIMATE	3,689.9	7,605.2											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	12	1.6	334.3	151.2	2,191.8	0.0	948.2	2,869.5	2,869.5	2,685.7
12-31-2026	12	2.5	220.3	126.9	0.0	0.0	930.6	2,985.1	5,854.6	5,284.2
12-31-2027	12	2.9	151.2	94.4	0.0	0.0	733.8	1,932.3	7,786.8	6,811.1
12-31-2028	12	3.0	114.9	76.1	0.0	0.0	612.5	1,392.5	9,179.4	7,811.1
12-31-2029	12	3.1	94.2	64.4	0.0	0.0	539.3	1,095.4	10,274.8	8,525.8
12-31-2030	14	3.7	84.6	61.1	84.2	0.0	495.7	883.8	11,158.6	9,047.5
12-31-2031	14	3.8	74.8	54.8	0.0	0.0	455.3	835.9	11,994.4	9,498.1
12-31-2032	14	3.8	67.1	49.6	0.0	0.0	423.0	734.1	12,728.6	9,857.7
12-31-2033	14	3.6	59.4	42.4	0.0	0.0	356.0	653.4	13,382.0	10,148.7
12-31-2034	13	3.2	53.8	37.9	0.0	0.0	320.5	587.7	13,969.7	10,386.6
12-31-2035	13	3.2	49.6	35.1	0.0	0.0	303.7	533.8	14,503.5	10,583.1
12-31-2036	13	3.2	46.0	32.6	0.0	0.0	288.7	487.3	14,990.8	10,746.1
12-31-2037	13	3.2	42.9	30.5	0.0	0.0	275.9	447.7	15,438.5	10,882.3
12-31-2038	13	3.1	39.4	28.6	0.0	68.8	259.5	336.6	15,775.1	10,975.9
12-31-2039	12	2.7	35.1	26.8	0.0	0.0	235.2	354.2	16,129.3	11,064.9
SUBTOTAL			1,467.4	912.5	2,276.0	68.8	7,178.1	16,129.3	16,129.3	11,064.9
REMAINING			375.4	254.0	0.0	3.7	2,649.0	4,007.1	20,136.5	11,536.6
TOTAL OF 50.0 YRS			1,842.7	1,166.5	2,276.0	72.5	9,827.1	20,136.5	20,136.5	11,536.6

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	12,487.6
12.000	10,753.5
15.000	9,802.2
20.000	8,610.2
25.000	7,727.4
30.000	7,040.1
35.000	6,485.8
40.000	6,026.8
45.000	5,638.9
50.000	5,305.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
BASE PRICE CASE

Table III

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED UNDEVELOPED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	3,224.1	14,086.7	862.0	29.6	2,448.2	68.71	20.96	4.149	59,224.0	619.4	10,157.9	0.0	70,001.4
12-31-2026	11,612.2	51,881.5	4,059.8	453.0	11,007.7	65.80	17.01	4.040	267,134.1	7,707.6	44,469.8	0.0	319,311.4
12-31-2027	11,269.3	58,580.6	4,658.9	614.5	14,130.4	63.80	15.82	3.889	297,223.9	9,719.4	54,959.7	0.0	361,903.0
12-31-2028	11,005.8	75,713.4	3,883.9	638.7	17,141.3	62.62	15.60	3.830	243,205.8	9,962.3	65,657.4	0.0	318,825.6
12-31-2029	10,250.2	78,080.3	3,097.0	510.7	16,369.4	61.91	15.33	3.861	191,731.4	7,830.2	63,194.3	0.0	262,755.9
12-31-2030	6,779.7	66,826.8	2,039.1	380.0	13,048.5	61.95	15.25	3.923	126,329.5	5,795.4	51,185.8	0.0	183,310.6
12-31-2031	4,496.8	48,588.1	1,476.0	302.7	9,718.9	61.98	15.19	3.892	91,478.1	4,598.2	37,826.8	0.0	133,903.1
12-31-2032	3,487.7	38,647.6	1,178.4	252.8	7,829.2	61.99	15.15	3.877	73,055.5	3,828.6	30,350.3	0.0	107,234.4
12-31-2033	2,869.7	32,245.5	983.9	217.6	6,583.0	62.00	15.11	3.867	61,002.9	3,287.5	25,456.9	0.0	89,747.3
12-31-2034	2,441.7	27,722.4	844.5	191.3	5,690.3	62.01	15.08	3.861	52,370.1	2,884.5	21,969.2	0.0	77,223.7
12-31-2035	2,127.8	24,352.6	739.5	170.8	5,017.5	62.02	15.05	3.856	45,860.6	2,572.0	19,348.2	0.0	67,780.7
12-31-2036	1,885.7	21,732.1	657.1	154.5	4,490.3	62.02	15.03	3.853	40,754.6	2,322.1	17,299.6	0.0	60,376.3
12-31-2037	1,692.8	19,632.3	590.7	141.1	4,065.5	62.02	15.01	3.850	36,635.3	2,117.6	15,651.6	0.0	54,404.5
12-31-2038	1,534.9	17,909.1	535.7	129.8	3,715.3	62.03	14.99	3.848	33,229.8	1,946.2	14,295.0	0.0	49,471.1
12-31-2039	1,403.0	16,466.9	489.4	120.2	3,420.9	62.03	14.97	3.846	30,353.3	1,799.4	13,156.6	0.0	45,309.3
SUBTOTAL	76,081.5	592,465.9	26,095.8	4,307.2	124,676.4	63.21	15.55	3.890	1,649,588.7	66,990.4	484,978.9	0.0	2,201,558.3
REMAINING	16,292.8	200,811.0	5,495.7	1,579.0	42,186.0	62.02	14.78	3.830	340,844.3	23,341.9	161,562.9	0.0	525,749.1
TOTAL	92,374.3	793,276.9	31,591.5	5,886.2	166,862.4	63.01	15.35	3.875	1,990,433.0	90,332.3	646,541.8	0.0	2,727,307.3
CUM PROD	0.0	0.0											
ULTIMATE	92,374.2	793,276.9											

PERIOD	NUMBER OF		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	36	16.9	4,776.4	182.5	139,517.0	0.0	5,723.2	-80,197.8	-80,197.8	-77,467.9
12-31-2026	120	61.2	19,044.9	3,213.1	335,673.0	0.0	32,233.5	-70,853.0	-151,050.8	-144,126.1
12-31-2027	173	101.1	19,390.9	5,048.9	188,540.8	0.0	41,884.4	107,037.9	-44,012.9	-60,906.6
12-31-2028	229	118.2	16,410.6	3,757.0	128,823.1	0.0	40,056.3	129,778.4	85,765.5	31,615.9
12-31-2029	277	127.1	13,559.6	2,403.0	72,047.1	0.0	33,412.9	141,333.4	227,098.9	123,136.8
12-31-2030	277	123.1	9,342.8	1,667.4	0.0	0.0	26,907.3	145,393.0	372,491.9	209,537.6
12-31-2031	277	125.0	6,809.5	1,287.2	0.0	0.0	22,503.6	103,302.8	475,794.7	265,276.8
12-31-2032	277	124.4	5,452.9	1,048.2	0.0	0.0	19,611.2	81,122.1	556,916.7	305,049.8
12-31-2033	277	123.3	4,563.0	883.4	0.0	8.4	17,595.1	66,697.4	623,614.1	334,769.9
12-31-2034	276	121.8	3,924.5	762.6	0.0	0.0	16,091.9	56,444.7	680,058.8	357,630.5
12-31-2035	276	120.6	3,442.9	670.4	0.0	0.0	14,939.8	48,727.6	728,786.4	375,569.2
12-31-2036	276	119.3	3,064.8	597.7	0.0	0.0	14,019.3	42,694.5	771,481.0	389,856.5
12-31-2037	276	118.2	2,759.5	538.9	0.0	0.0	13,265.5	37,840.5	809,321.5	401,367.3
12-31-2038	276	117.0	2,507.2	490.1	0.0	0.0	12,635.1	33,838.6	843,160.1	410,724.5
12-31-2039	276	116.0	2,294.4	448.5	0.0	0.0	12,098.2	30,468.2	873,628.2	418,383.4
SUBTOTAL			117,344.2	22,999.0	864,601.0	8.4	322,977.2	873,628.2	873,628.2	418,383.4
REMAINING			26,339.8	5,024.8	0.0	7,488.1	213,817.4	273,079.0	1,146,707.5	454,593.6
TOTAL OF 50.0 YRS			143,684.0	28,023.8	864,601.0	7,496.4	536,794.7	1,146,707.2	1,146,707.5	454,593.6

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	534,194.5
12.000	389,361.2
15.000	311,228.9
20.000	216,651.9
25.000	150,539.5
30.000	102,438.4
35.000	66,406.0
40.000	38,808.3
45.000	17,298.6
50.000	297.0

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
BASE PRICE CASE

TECHNICAL DISCUSSION
MAVERICK NATURAL RESOURCES, LLC INTEREST
PROPERTIES LOCATED IN THE UNITED STATES
AS OF JANUARY 1, 2025

1.0 GENERAL INFORMATION

At the request of Diversified Energy Company PLC (DEC) and Stifel Nicolaus Europe Limited, Netherland, Sewell & Associates, Inc. (NSAI) has estimated the proved reserves and future revenue, as of January 1, 2025, to the Maverick Natural Resources, LLC (Maverick) interest in certain oil and gas properties located in the United States. It is our understanding that DEC has entered into an agreement to purchase 100 percent of Maverick's interest in these properties, with an expected closing date in the first half of 2025. This Competent Person's Report (report) has been prepared using price and cost parameters specified by DEC, referred to as the Base Price Case.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE), the United Kingdom (UK) version of Regulation (EU) 2017/1129 that forms part of UK law by virtue of the European Union (Withdrawal) Act 2018 as amended, and the recommendations of the Financial Conduct Authority (FCA), as set out in Primary Market Technical Note 619.1 – the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA. This report has been prepared for use by DEC in connection with a prospectus to be published for admission of the ordinary shares proposed to be issued by DEC in connection with the acquisition of Maverick and a potential equity raise to the equity shares (commercial companies) category of the Official List and to trading on the London Stock Exchange's Main Market for listed securities. In our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The properties evaluated in this report are located in the United States. Maverick is an oil and gas company founded in 2018 with headquarters in Houston, Texas. Maverick's assets comprise conventional and unconventional shale reservoirs developed with vertical and horizontal wells, respectively. Two fields are under tertiary recovery mechanisms: CO_2 injection at Postle Field in Texas County, Oklahoma, and nitrogen (N_2) injection at Jay Field in Escambia and Santa Rosa Counties, Florida and Escambia County, Alabama. Maverick's asset base includes interest in approximately 11,900 gross wells; approximately half are operated by Maverick. Approximately two thirds of the wells are actively producing oil and gas which, with processing, also includes the sale of natural gas liquids (NGL). The remaining wells are not currently producing. Also, approximately 2,200 of the actively producing wells are not economic at the price and cost parameters used in this report. For the purposes of this report, Maverick's assets have been grouped into the following business units: Anadarko, Ark-La-Tex, Florida, MidCon, MidWest, Permian, and Rockies. A location map of these assets by business unit is shown in Figure 1. Each well may have one or multiple land leases with different terms, duration, and other principal conditions of rights, including environmental and abandonment obligations. In general, once a well begins producing, the lease remains in effect until production operations cease. All wells have available power, water, and human resources and meet occupational health and safety requirements.

We estimate the gross economic well count and the net reserves and future net revenue to the Maverick interest in these properties, as of January 1, 2025, to be:

Category	Gross Economic Well Count	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Future Net Revenue (M$) Total	Present Worth at 10%
Total Proved	6,294	94,588.9	56,996.7	713,329.3	3,507,990.0	1,984,597.2

The oil volumes shown include crude oil and condensate. Oil and NGL volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue shown in this report is Maverick's share of the gross (100 percent) revenue from the properties prior to any deductions and, as requested, includes the revenue associated with the sale of sulfur; the revenue attributable to sulfur is shown herein as "other" revenue. Future net revenue is after deductions for Maverick's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Maverick interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Maverick receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

In accordance with FCA recommendations, the following table shows Maverick's historical production and operating costs for the past three years:

Parameter	2022	2023	2024
Net Production (BOE/day)	68,773	67,901	60,586
Net Operating Cost ($/BOE)	14.00	12.90	13.32

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil- or gas-producing area in the world. Our staff is familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the United States Securities and Exchange Commission, Alberta Securities Commission, SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

2.0 DATA

We have not independently verified the accuracy and completeness of information and data furnished by Maverick with respect to well logs, geologic maps, ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data.

3.0 GEOLOGY AND GEOPHYSICS

3.1 ANADARKO BUSINESS UNIT

The Anadarko Business Unit properties are located in the Anadarko Basin, which is located in western Oklahoma and the eastern Panhandle of Texas and covers an area approximately 22,000 square miles. The Anadarko Basin contains as much as 25,000 feet (ft) of sedimentary rock mostly deposited during the Devonian, Mississippian, and Pennsylvanian ages. The productive stratigraphic interval ranges from 1,000 to over 20,000 ft in depth. The main productive reservoirs in the basin, from oldest to youngest, are the Arbuckle carbonates, Woodford Shale, Mississippian carbonates, and Pennsylvanian sands and limestones. Oil and gas production has been developed in shallow Pennsylvanian sandstones and limestones, with vertical development beginning in the 1930s.

The unconventional horizontal development of oil and gas in Oklahoma was initiated in the Devonian Woodford Shale in 2002 and extended to drilling horizontal wells in most of the Mississippian and Pennsylvanian reservoirs throughout the basin. A stratigraphic column of the Anadarko Basin is shown in Figure 2.

3.2 ARK-LA-TEX BUSINESS UNIT

The Ark-La-Tex Region comprises southern Arkansas, northern Louisiana, and northeastern Texas. Maverick's properties in the Ark-La-Tex Business Unit are located in Lafayette and Columbia Counties in Arkansas, Webster Parish in Louisiana, and Upshur and Gregg Counties in Texas. The Arkansas and Louisiana properties target the Smackover and Cotton Valley Formations, and the Texas properties target the Cotton Valley Formation. Oil production in the Jurassic-aged Smackover Formation, which exceeds 1,000 ft in thickness in some locations, is from oolitic limestones in the upper part of the interval. Production in the Cotton Valley Formation is from interbedded sequences of sandstone and shale. The total thickness of the Cotton Valley Formation, which ranges from Jurassic to Lower Cretaceous age, is greater than 3,000 ft. A stratigraphic column for the properties in the Ark-La-Tex Region is shown in Figure 3.

3.3 FLORIDA BUSINESS UNIT

The Florida Business Unit properties are located in two main areas: the Florida Panhandle and South Florida. The Florida Panhandle properties target the Smackover Formation and are located in Escambia and Santa Rosa Counties, Florida as well as the adjacent Escambia County, Alabama. The South Florida properties target the Sunniland Formation and are located in Collier, Hendry, and Lee Counties, Florida.

3.3.1 Florida Panhandle

The Florida Panhandle properties are located in the Jay Trend of southwestern Alabama and northwestern Florida in Big Escambia Creek, Little Escambia Creek, and Jay Fields. These fields are located along a normal fault complex that rims the Gulf Coast to the west through Alabama and into Texas. Jay Field was discovered in 1970 with the drilling of a well that produced from the Smackover Formation at depths of 15,470 to 15,524 ft. The Smackover Formation is a limestone and dolostone unit in this area, with the Buckner Formation serving as the cap rock. Jay Field uses N_2 injection to increase overall oil recovery. A stratigraphic column for the Florida Panhandle and southern Alabama is shown in Figure 4.

3.3.2 South Florida

The South Florida properties produce from the Late Cretaceous-aged Sunniland Formation in a trend area that is approximately 145 miles long and 12 miles wide. The Sunniland Formation was discovered in 1943. Oil is produced at depths over 10,500 ft below the surface. Maverick's South Florida properties are located in Bear Island, Sunniland Oil, Raccoon Point, and West Felda Fields. The Sunniland Formation is relatively uniform in thickness and consists of limestone, dolomite, and anhydrite. A stratigraphic column for South Florida is shown in Figure 5.

3.4 MIDCON BUSINESS UNIT

The MidCon properties are located in Postle Field in Texas County, Oklahoma, within the Western Anadarko Basin. Postle Oil Field was discovered in 1958 and covers approximately 40 square miles. It produces from Pennsylvanian Morrow Sandstones at a depth of approximately 6,100 ft. The Morrow Sandstones have an average thickness of 28 ft. More recently, enhanced oil recovery operations have aimed to increase production. A stratigraphic column of the Oklahoma Basins is shown in Figure 6.

3.5 MIDWEST BUSINESS UNIT

The MidWest properties are located in Corydon Field in Harrison County, Indiana, within the Illinois Basin. Corydon Field targets the New Albany Shale, which is of Devonian to Mississippian age. The New Albany Shale is 100 to 140 ft thick in southeastern Indiana and dips and thickens to the southwest into the Illinois Basin, where it attains a thickness of more than 360 ft. A stratigraphic column of the Illinois Basin in southern Indiana is shown in Figure 7. No wells in the MidWest Business Unit are currently producing or scheduled to produce oil and gas in the future.

3.6 PERMIAN BUSINESS UNIT

The Permian Business Unit properties are located in the Permian Basin, which is a large sedimentary basin located in west Texas and southeastern New Mexico that covers an area greater than 86,000 square miles. The Permian Basin comprises several subbasins, including the Northwest Shelf, Delaware Basin, Central Basin Platform, and Midland Basin. Maverick's interest includes properties in the Northwest Shelf and the Central Basin Platform. Deposition of the Permian Basin began in the Lower Ordovician period of the Paleozoic era, and the basin comprises multiple stacked petroleum reservoirs. The main productive reservoirs in the basin, from oldest to youngest, are the Ellenberger, Devonian, Morrow, Canyon, Avalon, Bone Springs, Yeso, Wolfcamp, Spraberry, Clear Fork, San Andres, and Yates Formations. Maverick's Permian Basin properties produce from formations that were deposited during the Permian period.

Unconventional drilling commenced in the Permian Basin in the early 2010s and extended to the Spraberry and Wolfcamp Formations and many other Permian-aged reservoirs throughout the basin. A stratigraphic column of the Permian Basin is shown in Figure 8.

3.6.1 Central Basin Platform

The Central Basin Platform is located in the center of the Permian Basin, with the Delaware Basin to the west and the Midland Basin to the east. The majority of the vertical wells in the Central Basin Platform produce from the San Andres Formation and Clear Fork Group at depths between 3,000 and 10,000 ft. Horizontal wells produce from the Wolfcamp, Bone Springs, and Spraberry Formations. Typical horizontal producing depths range from 5,000 to 14,000 ft, with typical horizontal completion lengths ranging from 3,500 to 6,000 ft, though more recent completions have reached horizontal completion lengths greater than 10,000 ft.

3.6.2 Northwest Shelf

The Northwest Shelf is the northwesternmost portion of the Permian Basin, directly north of the Delaware Basin. The majority of the vertical and horizontal wells in the Northwest Shelf produce from the San Andres and Yeso Formations at depths between 3,000 and 10,000 ft. Typical horizontal completion lengths range from 1,500 to 4,000 ft, while recent completions have reached horizontal completion lengths greater than 6,000 ft.

3.7 ROCKIES BUSINESS UNIT

The Rockies comprise a discontinuous series of mountain ranges that stretch from northern British Columbia in Canada through Idaho, Montana, Wyoming, Utah, Colorado, and down to central New Mexico in the United States. They are approximately 3,000 miles long and up to 400 miles wide in certain areas. The hydrocarbon-bearing fields of the Rockies are found in several structural basins. Key productive areas include the Green River and Niobrara Formations and the Bighorn, Piceance, Powder River, and San Juan Basins. Historically, much of the oil and gas in the Rockies was produced from traditional reservoirs. More recently, shale gas and tight oil have become increasingly important in the region and methane has been produced from coal beds, particularly in the Powder River Basin. The factors that govern the accumulations in the Rockies are varied because of the wide range of geological conditions under which the beds were deposited. Maverick's properties in the Rockies Business Unit are located in the Bighorn Basin, the Green River Formation, and the Powder River Basin.

3.7.1 Bighorn Basin

The Bighorn Basin is located in north-central Wyoming and covers an area of approximately 8,500 square miles. This basin contains as much as 20,000 ft of sedimentary rock from Cambrian to Miocene age. The productive stratigraphic interval ranges from approximately 1,000 to 14,500 ft in depth. The main productive reservoirs in the basin, from oldest to youngest, are the Madison Limestone, Tensleep Sandstone, Phosphoria Formation, Cloverly Formation, and Frontier Sandstone. Oil was first discovered in the basin in the 1880s and has been produced from more than 30 reservoirs across more than 125 fields. A stratigraphic column of the Bighorn Basin is shown in Figure 9.

3.7.2 Green River Formation

The Green River Formation is located near the Green River in western Colorado, eastern Utah, and southwestern Wyoming, covering an area of approximately 25,000 square miles. The sediments of the Green River Formation were deposited in very fine layers during the Cenozoic (Eocene) age. Each pair of layers is called a varve and represents one year. The sediments of the Green River Formation present a continuous record of six million years, with a mean varve thickness of 0.18 millimeters. A stratigraphic column of the Green River Formation is shown in Figure 10.

3.7.3 Powder River Basin

The Powder River Basin is located in southeastern Montana and northeastern Wyoming, covering an area of approximately 19,500 square miles. The Powder River Basin contains sedimentary rocks deposited during the Pennsylvanian, Permian, Triassic, Jurassic, and Cretaceous ages. The productive stratigraphic intervals generally range from 2,000 ft for shallow coalbed methane production to over 10,000 ft for more conventional oil and gas reservoirs. Key productive reservoirs in the basin, from oldest to youngest, include the Fall River Formation, Muddy Sandstone, Mowry Shale, Frontier Formation, Turner Sandstone, Niobrara Shale, and Shannon, Sussex, Parkman, Teapot, and Teckla Sandstones. A stratigraphic column of the Powder River Basin is shown in Figure 11.

4.0 CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS AND TERTIARY RECOVERY MECHANISMS

Included in this evaluation are 3,033 conventional and 5,218 unconventional wells producing oil and gas which, with processing, also includes the sale of NGL. For the proved developed producing properties, we estimate the gross economic well count and the net reserves and future net revenue to the Maverick interest by well type, as of January 1, 2025, to be:

Well Type	Gross Economic Well Count	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Future Net Revenue(1) (M$) Total	Present Worth at 10%
Conventional	2,448	33,180.0	7,152.3	82,192.3	1,062,590.2	559,461.4
Unconventional	3,558	29,250.6	43,910.2	463,717.6	2,184,549.8	1,179,672.1
Total	6,006	62,430.6	51,062.5	545,909.7	3,247,140.0	1,739,133.4

Totals may not add because of rounding.

(1) Excludes maintenance capital and abandonment costs.

The full life cycle of both conventional and unconventional wells well can be summarized as four main phases: location preparation, drilling and completion, production operations, and abandonment or asset retirement.

4.1 CONVENTIONAL WELLS

Conventional wells are drilled into and produce from conventional reservoirs. Conventional reservoirs typically consist of sandstones or carbonates, such as limestone or dolomite, with sufficient porosity and permeability to store oil and gas within the rock matrix. Porosity is the measure of the amount of void spaces or pores in a given rock or material that can store trapped fluids. Permeability is a measure of the ability of fluid to flow through a given rock. Porosity and permeability are related rock properties of conventional reservoirs. A rock may be extremely porous, but if the pores are not well-connected, it will have limited permeability. Likewise, a rock may have natural fractures that allow fluid to flow through it, but if it is not very porous, it will have limited fluid storage capacity. While a number of such wells can produce sufficient quantities of oil and gas without stimulation, some conventional wells require hydraulic fracturing to enhance production because of the reservoir rock properties. Stimulation projects for conventional wells are much smaller in scope than those required for unconventional wells.

The typical well pad prepared for a conventional oil or gas well is sized to accommodate the drilling rig footprint with nominal support equipment during drilling operations. After drilling and completion operations conclude, the location can typically be reduced in size to accommodate minimal onsite processing equipment to support the well. Conventional well sites are generally smaller than unconventional well pads and can more easily be adapted to blend into the existing terrain.

Once the pad site has been prepared, drilling operations can commence. First, the surface hole is drilled vertically to a depth ranging from 150 to 1,500 ft, depending on local requirements for the protection of surface waters. Next, steel surface casing is lowered into the well and cemented into place. Vertical drilling can then proceed through the intermediate hole section and potentially to the target depth of the well using a drill bit of seven to nine inches in diameter. An intermediate casing string may be required in the well to isolate specific formations or pressure-depleted zones. Once the desired total depth is reached, the production casing can be lowered into the well and cemented in place. Since the production casing and cement isolate the target reservoir from the wellbore, the well must be perforated through the casing, cement, and formation rock to reestablish communication for production. Generally, the well is then stimulated with either acid or a fracture treatment. Finally, production tubing is set in the well to allow oil and gas to flow to the surface. A wellhead is then installed at the surface of the well for pressure and flow control. This is a generalized and simplified overview of the drilling and completion process for conventional wells that may vary based on actual downhole conditions from well to well.

Once drilling and completion operations are concluded and the associated support equipment is removed, a conventional oil or gas well is ready to commence the production phase. Wellhead pressures of newly drilled conventional wells are highest at the start of production. As pressure and production rates decrease over time, artificial lift methods such as rod pumping or plunger lift may be required to help maintain production. In some cases, well productivity of older wells can be enhanced by certain workover activities, well stimulation, or installation of downhole equipment.

4.2 UNCONVENTIONAL WELLS

An unconventional well differs from a conventional well in that it is drilled into and typically produces from the source rock for oil and gas. An unconventional well typically employs horizontal drilling and significant hydraulic stimulation. These techniques are required because, although unconventional formations contain large quantities of stored hydrocarbons, they typically have extremely low permeability, which inhibits the flow of reservoir fluids. Large hydraulic stimulations are required to enhance the formation's ability to flow hydrocarbons at commercial production rates.

The typical well pad site prepared for unconventional oil or gas wells reflects the greater footprint requirements of the initial drilling, completion, and stimulation operations. Unconventional well pads are larger than conventional pads as a result of the increased amount of equipment needed for the hydraulic stimulation required for the wells. In addition, most unconventional well pads accommodate multiple wells. In an effort to minimize surface disturbance and maximize facility utilization, unconventional well pads may be designed for multiple wellheads and their associated processing equipment. Multiple factors contribute to the well pad size considerations, including lease unit configuration and lateral well spacing, surface topography, site access, and the number of productive zones or benches being targeted.

The initial steps in drilling an unconventional well are very similar to those for conventional wells. Unconventional wells are initiated and drilled vertically to depths just above the target formation, then turned horizontally using directional drilling equipment to penetrate the reservoir. Drilling horizontally through the target formation maximizes the reservoir surface area contacted by the well. In a vertical well, the wellbore intersects the reservoir perpendicularly, so exposure to the productive zone is limited by the vertical thickness of the zone. By contrast, exposure to the producing zone in a horizontal well is limited only by the length of the lateral section drilled in the well.

Completion of a horizontal well can be achieved by installing production casing over the entire length of the lateral wellbore or by leaving the lateral as an open hole. For cased completions, selectively perforating the lateral section provides additional exposure to the reservoir, which leads to greater connectivity for the oil and gas to flow into the well. In addition, large hydraulic stimulation (frac) treatments are required to maximize the flow of hydrocarbons from the reservoir to the wellbore. Large volumes of water mixed with certain additives are pumped at high pressure and high rate into the well and out into the rock formation to create fractures or connect existing natural fractures through which the oil and gas can ultimately flow. Once sufficient fluid has been pumped to initiate the fracture, additional fluid is pumped with sand or some other type of proppant to fill and hold the fractures open once the pumping pressure is relieved. The proppant also provides a permeable flowpath for the oil and gas to flow into the wellbore.

An unconventional oil or gas well is completed with a wellhead at the surface similar to a conventional well. The unconventional well pad site typically has multiple wellheads and multiple processing vessels and storage tanks. Surface facility designs must account for large production capacities due to the high initial rates and pressures and the number of producing wells planned for the pad. As previously described, pressure and production rates decrease over time and operators often use artificial lift techniques such as rod pump, plunger lift, or gas lift to help maintain well productivity. In some cases, well productivity can be enhanced by workover activities or restimulation.

4.3 TERTIARY RECOVERY MECHANISMS

Certain properties in this evaluation produce from conventional reservoirs utilizing tertiary recovery techniques. Tertiary recovery is also known as enhanced oil recovery and is the third stage used to extract oil from a reservoir after the primary stage of pressure depletion and secondary stage of water or gas injection.

The properties under tertiary recovery mechanisms are located in Postle Field in Texas County, Oklahoma, which utilizes CO_2 injection, and in Jay Field in Escambia and Santa Rosa Counties, Florida and Escambia County, Alabama, which utilizes N_2 injection. It is expected that these operations will continue until the operator deems them to be uneconomic.

5.0 METHODS OF RESERVES DETERMINATION

Decline curve analysis (DCA) and analogy were the primary tools for projecting reserves for the majority of the producing properties, most of which have significant historical production. These methodologies are generally considered the most reliable methods for forecasting reserves wells of this type with consistent operating conditions.

5.1 DECLINE CURVE ANALYSIS

In general, DCA consists of using a well's historical production characteristics to forecast future production trends. Individual well-level DCA is performed on each producing well and was deemed to be the most appropriate method of evaluating the reserves for these wells. In ten instances, DCA was performed at the unit level because well-level production was not available. Analysis by DCA should give a reasonable forecast of reserves for the current completion in each well and thus the fields as a whole. It can also help identify variations in well performance throughout the field and areas with remaining hydrocarbons. Two of the most common types of forecasting methods are exponential decline and hyperbolic decline; the projections used for this evaluation are all based on these two methods.

In this evaluation, DCA entailed using rate-time analysis wherein historical production is plotted on the vertical axis using a logarithmic scale and time is plotted on the horizontal axis using a linear scale. If the historical data when plotted versus time in this method form a straight line, then the decline is considered an exponential decline. A forecast of future production can be made by fitting historical data with a straight line and extrapolating that line into the future. The key forecast parameters are initial oil and gas forecast rates and the exponential decline rate. The initial forecast rate is the rate at the start of the forecast, and the exponential decline rate is the percentage the forecast declines each year. The average decline of wells projected using exponential decline in this evaluation, weighted by production, is 6.3 percent per year.

Once the forecast parameters are estimated, a month-by-month forecast of oil and gas volumes can be made for each well. Approximately 71 percent of the active wells evaluated in this report have been forecasted using exponential DCA.

Many wells, including virtually all horizontal wells drilled into unconventional reservoirs, demonstrate a decline profile with a very high initial decline rate that decreases to a lower exponential final decline rate over time. Production for these wells cannot be modeled with an exponential decline curve, but requires instead a hyperbolic decline curve. This historical production trend generates a curved production profile. Wells that demonstrate this production profile may have initial decline values ranging from 35 percent to more than 90 percent in the first year. However, the annual decline rate decreases each year that the well produces.

A hyperbolic projection is created by matching the forecast line to historical production data to determine three critical parameters: initial production rate, initial decline rate, and hyperbolic b-factor (b-factor). The initial production rate and initial decline rate are similar to exponential decline forecasts. The b-factor determines the curvature for the forecast; the higher the b-factor, the faster the decline profile flattens out.

Once the decline rate reaches a predetermined value, the curved hyperbolic forecast transitions to a final exponential decline. This final decline represents the average final exponential decline established by existing wells in the field with long production histories. It is expected that newer wells still exhibiting hyperbolic decline will ultimately reach exponential decline at a rate similar to other wells in the area. The final decline rate is estimated based on analogy to other wells in the area producing from similar reservoirs. The average final exponential decline of wells projected using hyperbolic decline in this evaluation, weighted by production, is 6.1 percent per year.

Many of the wells evaluated in this report have produced for over 15 years with the potential for another 50 years or more of productive life. These production profiles indicate wells with long life and very predictable future production rates. Reserves for individual wells are limited to the shorter of the well's economic life or 50 years from the as-of date of this report (January 1, 2025).

5.2 ANALOGY

For wells with limited to no production history, the primary methodology used to determine reserves was analogy. This began with the selection of a set of producing wells that are analogous to the wells being evaluated. Considerations in selecting analogous wells include the reservoir interval, well and completion design characteristics, and proximity. The production history of the analogous wells was then normalized to time zero and, for horizontal wells, normalized by lateral length. The average production normalized over time for the analogous wells guided the expected production profile. When using this methodology, care must be taken to consider the well life of each analog and its impact on the calculated average rates; certain portions of the result may not be statistically useful. The estimated ultimate recovery from the analogous wells were normalized to a per-foot basis and compared to the production profile generated from the type curves; adjustments were made to the type curves as needed.

Two of the largest concentrations of proved undeveloped locations where we used this methodology target the Excello and Paddock Reservoirs, which are located in the Anadarko and Permian Business Units, respectively. Figures 12 and 13 illustrate the existing proved developed producing wells that are available to serve as analogs to the surrounding undeveloped locations. In the case of the Paddock Reservoir, certain vertical wells are shown, but are not considered analogous.

6.0 ECONOMIC PARAMETERS

6.1 PRODUCT PRICES

As requested, this report has been prepared using Base Price Case oil, NGL, gas, and sulfur price parameters specified by DEC. Oil and NGL prices are based on NYMEX West Texas Intermediate (WTI) prices and are adjusted for quality, transportation fees, and market differentials. Gas prices are based on NYMEX Henry Hub prices and are adjusted for energy content, transportation fees, and market differentials. The sulfur price is $116 per metric ton. Oil, NGL, and gas prices, before adjustments, are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2025	69.87	3.527
12-31-2026	66.70	3.907
12-31-2027	64.88	3.841
12-31-2028	63.81	3.729
Thereafter	63.07	3.584

6.1.1 Price Adjustments

Oil price basis differentials represent the difference between the oil prices realized at local or regional delivery points and the oil prices realized at Cushing, Oklahoma, which is a major trading hub for crude oil and is the price settlement point for WTI oil on the NYMEX. Gas price adjustments represent the difference between the gas prices realized at local or regional delivery points and the gas prices realized at the Henry Hub pipeline, located in Erath, Louisiana, which serves as the official delivery location for all NYMEX futures gas contracts.

For the purposes of this report, price adjustments are based on Maverick's historical operating statements for the last 12 months. Adjustments for oil, NGL, and gas were calculated by month by comparing the actual prices received to the NYMEX WTI average near-month prices for oil and the NYMEX Henry Hub last trade day settlement prices for gas. NGL adjustments are based on a ratio of actual prices received compared to NYMEX WTI average near-month prices for oil.

6.1.2 Price Sensitivities

In accordance with FCA recommendations, Low and High Price Case sensitivities were prepared. Summary projections of reserves and revenue by reserves category for the Low and High Price Cases are shown in Figures 14 through 21. Prices for the Low and High Price Cases are 10 percent lower and higher than the Base Price Case, respectively. The sulfur price is $104 per metric ton for the Low Price Case and $128 per metric ton for the High Price Case. Oil, NGL, and gas prices for the Low and High Price Cases, before adjustments, are shown in the following table:

	Low Price Case		High Price Case	
Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2025	62.88	3.174	76.86	3.880
12-31-2026	60.03	3.516	73.37	4.298
12-31-2027	58.39	3.457	71.37	4.225
12-31-2028	57.43	3.356	70.19	4.102
Thereafter	56.76	3.226	69.38	3.942

6.2 OIL AND GAS MARKETING AND TRANSPORTATION

6.2.1 Anadarko Business Unit

Crude oil is trucked from the wellhead. Oil API quality ranges from approximately 30 to 60 degrees, with an average in the mid-40s. Maverick operates the Wheeler Terminal and approximately 60 percent of sales are made to Sunoco LP. Other purchasers are Valero Energy Corporation (Valero) and Plains All American

Pipeline (Plains). Valero operates the McKee Refinery, which is the largest refinery in the basin. Plains has connectivity to Cushing, Oklahoma, where the NYMEX WTI oil futures contracts are delivered.

The main gatherers and processors for gas include The Williams Companies, Inc. (Williams), MarkWest Energy Partners, L.P. (MarkWest), Energy Transfer LP (Energy Transfer), and Producers Midstream. Most sales are under long-term deals with acreage dedications and the majority of processing contracts allow for monthly ethane elections. Williams provides gathering service only and delivers to various processors. MarkWest operates multiple gathering systems in the basin. Energy Transfer and Producers Midstream both provide gathering and processing services through numerous contracts.

6.2.2 Permian Business Unit

Oil sales volumes are roughly evenly split between pipeline and trucked. The majority is sold directly to end users who provide the highest netback. The oil quality is mostly sour, with high metals and hydrogen sulfide (H_2S) and average API gravity in the high-30s. The current sales are mostly to Phillips 66 and HF Sinclair Corporation.

The gas is also mostly sour because of H_2S content. In Texas, DCP Midstream Partners (DCP), which is owned by Phillips 66, is the primary midstream partner providing the gathering, treating, processing, and purchasing of residue gas. In New Mexico, there are multiple partners providing the same services, including Targa Resources Corporation, Kinetik Holding Inc., DCP, and a local processing plant named East Vacuum, which is operated by Maverick.

6.2.3 Other Business Units

Within the Rockies Business Unit, oil production from Greasewood Field, where average oil gravity is approximately 35 degrees API with high paraffin content, is trucked to Par Pacific's refinery in Newcastle, Wyoming. In Southwestern Wyoming, the average oil gravity is 49 degrees API and all oil is trucked and sold to Plains. Gas is gathered and redelivered at plant tailgates by various midstream providers such as Williams, Mountain Gas, and Concord Energy.

Within the Florida Business Unit, oil from Jay Field is sold to Shell plc via the Alabama/Florida Pipeline System owned by Genesis Energy, L.P., which directly connects to Vertex Refining Alabama LLC's refinery in Mobile, Alabama. NGLs are extracted and propane is sold via truck to Dufour Marketing, Inc. and butane is sold to NGL Supply Co. Ltd. For the properties in South Florida, the oil is trucked from the field by Eagle Transport Corporation and delivered to a terminal in Tampa operated by Martin Midstream Partners L.P.

For the properties in the MidCon Business Unit, all oil is sent via pipeline to a central tank battery and then delivered to the CHS Refinery located in McPherson, Kansas; the oil API quality averages in the low-40s.

6.3 NGL YIELDS AND GAS SHRINKAGE

NGL yields and gas shrinkage used in this report are based on the operating expense records of Maverick. NGL yields are calculated as the volume of NGL processed from gas plants divided by the wellhead gas volume. Gas shrinkage is the amount of gas lost during processing, fuel use, and flare and is calculated as a percentage of wellhead gas volumes. Average NGL yields and gas shrinkage weighted by production over the remaining lives of the properties are shown for each business unit in the following table:

Business Unit	Average NGL Yield (BBL/MMCF)	Average Gas Shrinkage (%)
Anadarko	75.5	21.4
Ark-La-Tex	51.4	24.0
Florida	10.8	100.0
MidCon	1.1	100.0
MidWest(1)	0.0	0.0
Permian	56.8	72.5
Rockies	52.7	2.5

(1) No wells in the MidWest Business Unit are currently producing or scheduled to produce oil and gas in the future.

6.4 OPERATING EXPENSES

Operating costs used in this report are based on operating expense records of Maverick. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. As requested, the per-well costs for the operated properties include credits to operating expenses associated with overhead recovery allowed under joint operating agreements; however, these credits have not been used to determine economic limits for the properties. The current overhead recovery amount is less than 5 percent of the first-year estimated operating costs for the proved developed producing category. Headquarters general and administrative overhead expenses of Maverick are included to the extent that they are covered under joint operating agreements for the operated properties. As requested, operating costs are not escalated for inflation. Average operating costs weighted by production over the remaining lives of the properties are shown for each business unit in the following table:

			Gross Per-Unit Costs			
Business Unit	Fixed Cost ($/Well/Month)	NGL Processing ($/MCF)(1)	Oil ($/BBL)	Gas ($/MCF)(1)	Water ($/BBL)	Overhead ($/Well/Month)
Anadarko	914	0.237	1.22	0.198	0.00	(90)
Ark-La-Tex	634	0.000	20.75	0.572	0.00	(154)
Florida	9,963	0.254	3.41	0.302	0.30	(319)
MidCon	1,698	0.008	20.16	0.102	0.13	(14)
MidWest(2)	0	0.000	0.00	0.000	0.00	0
Permian	1,296	0.082	3.18	0.483	0.00	(240)
Rockies	623	0.212	9.96	0.204	0.00	(157)

(1) $/MCF costs are applied prior to shrinkage.
(2) No wells in the MidWest Business Unit are currently producing or scheduled to produce oil and gas in the future.

6.5 CAPITAL COSTS

Capital costs used in this report were provided by Maverick and are based on internal planning budgets. Capital costs are included as required for facility and field maintenance, workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Net capital costs, by business unit, are shown in the following table:

Business Unit	Maintenance And Production Equipment (M$)	Workovers (M$)	New Development Wells (M$)	Total (M$)
Anadarko	137,645.4	296.6	450,453.5	588,395.5
Ark-La-Tex	22,135.1	861.6	0.0	22,996.7
Florida	33,688.3	0.0	0.0	33,688.3
MidCon	10,474.6	0.0	7,489.0	17,963.6
MidWest(1)	0.0	0.0	0.0	0.0
Permian	103,325.9	473.6	406,658.5	510,458.0
Rockies	28,408.4	644.2	0.0	29,052.5
Total	335,677.6	2,276.0	864,601.0	1,202,554.6

Totals may not add because of rounding.

(1) No wells in the MidWest Business Unit are currently producing or scheduled to produce oil and gas in the future.

Proved undeveloped locations are scheduled to be drilled and completed through 2029. For the Base Price Case, the number of these locations expected to be completed each year is shown in the following table:

Year	Undeveloped Locations
2025	36
2026	84
2027	53
2028	56
2029	48
Total	277

6.6 ABANDONMENT COSTS

Abandonment costs used in this report, further described in Section 8.0, are Maverick's estimates of the costs to abandon the wells and production facilities, net of any salvage value. As requested, abandonment costs are not escalated for inflation.

6.7 SEVERANCE AND AD VALOREM TAXES

State severance taxes and county ad valorem taxes used in this report are based on the operating expense records of Maverick. Average severance and ad valorem tax rates to the Maverick interest weighted by production over the remaining lives of the properties are shown for each business unit in the following table:

Business Unit	Oil/NGL/Gas Severance Tax (% of Revenue)	Ad Valorem Tax[1] (% of Revenue)
Anadarko	4.32	0.82
Ark-La-Tex	3.42	2.42
Florida	3.30	3.21
MidCon	5.97	0.00
MidWest[2]	0.00	0.00
Permian	5.92	2.03
Rockies	5.65	7.43

(1) Ad valorem taxes are calculated as a percentage of revenue after deducting severance taxes.
(2) No wells in the MidWest Business Unit are currently producing or scheduled to produce oil and gas in the future.

7.0 INTERESTS

In the United States, minerals can be developed on both private and public lands; properties in this evaluation are located in both. Rights to development on private land entail either direct ownership rights (i.e., the operator owns the minerals) or lease rights (i.e., the operator leases the minerals from the owner). In a lease arrangement, the property owner (lessor) grants rights to the operator (lessee) for the exploration and development of the minerals. In some cases, the real property rights have been severed so the owner of the surface property does not own the mineral rights. In either case, the lease rights or mineral ownership rights of the operator provide permission to access the surface of the property for the extraction of minerals. On publicly owned properties, the minerals are developed by the operator pursuant to a license or permit from the government or public owner. Both private leases and government licenses require the operator to pay a royalty to the mineral owner as compensation for extracting the oil and gas that has been developed. Typically, the royalty interest is a fraction of the gross sales revenue, usually between 12.5 and 25.0 percent.

Leases generally have two components: the primary term and the secondary term. The primary term is a set number of years or months to generate activity, and the secondary term exists as long as oil or gas is produced from the lease. In addition to the primary term, lease extensions may be obtained if the primary term is set to expire before the operator has begun exploring on the lease or established production from it. Leases that have production underway are deemed to be "held by production" and will remain in force until production can no longer be sustained in commercial quantities.

8.0 ASSET RETIREMENT OBLIGATION

The asset retirement obligation describes the operator's financial and environmental obligation to abandon uneconomic wells.

Prior to retiring any well, the operator completes a thorough assessment to determine the future utility of the well. If future production or use is not feasible, the operator will schedule the well for decommissioning. The operator's decision process for selecting a well for decommissioning considers four criteria: (1) does the well pose a safety concern, (2) does the well pose an environmental concern, (3) is the well included in an existing agreement with a state agency to be decommissioned, and (4) are there other factors to consider such as changes to areas around the well (e.g., economic development).

Costs to plug a well can vary significantly for a number of reasons, including region, depth of producing formation, type of well (vertical or horizontal), local regulations and requirements, and the overall mechanical condition of the well. The costs to retire a well include permitting and design, access to the physical wellsite, the actual cost of decommissioning the well, disposition of salvageable equipment, removal and disposal of unsalvageable well and facility equipment, and surface reclamation.

State and federal regulatory agencies require submission of a permit prior to the commencement of plugging operations. Once a well is selected for decommissioning, the operator will apply for the proper permit in advance of the planned operation. In preparation for the plugging operation, well records and the well site are examined to prepare a work plan, wellbore diagram, and budget estimate for the project. If working interest partners are involved in the well, a funding request must be sent to the partners for approval. Once regulatory approval is granted, which may or may not include revisions to the originally proposed operation, the abandonment operation can be planned for execution. A service rig, cementing services, and other necessary equipment and services can then be procured and scheduled. Contact with the regional regulatory inspector is typically required prior to commencement of the project and often includes witnessing various operations within the project. Site reclamation is subject to Bureau of Land Management review and approval.

Once an approved permit is obtained, the specifics of the plugging operation are known, such as number of cement plugs and thickness required, locations for the cement plugs, necessity for the removal of certain downhole components, perforation of certain casing components, and surface condition of the plugged well site. Often, a regulatory official is onsite to witness that the specified activities and cement plugs are executed as proposed in the permit.

Once the well has been plugged, the operator submits the required documentation and records to the state regulatory agency. A plugging certificate is generally retained and recorded by the regulatory agency. The wellsite is reclaimed and returned to its previous natural condition as specified by the state regulatory requirements and the lease agreement with the property owner. A permanent marker is often placed on the well location designating it as decommissioned, although certain states do not require a marker. All forms and final permits are approved and finalized by the state regulatory inspectors, providing the operator with the appropriate records signifying completion of the project.

As with any oil and gas operation, the processes, procedures, and regulatory requirements outlined herein may vary by state and region of operation. The explanations outlined above describe the general process of asset retirement as it applies to a large majority of the wells included in this evaluation. There are situations and instances where additional work and processes may be required as a result of mechanical well condition or failure history. While these situations are not typical, they may result in additional time and cost for the asset retirement project of certain wells. State regulations and requirements should be reviewed when considering general well plugging requirements.

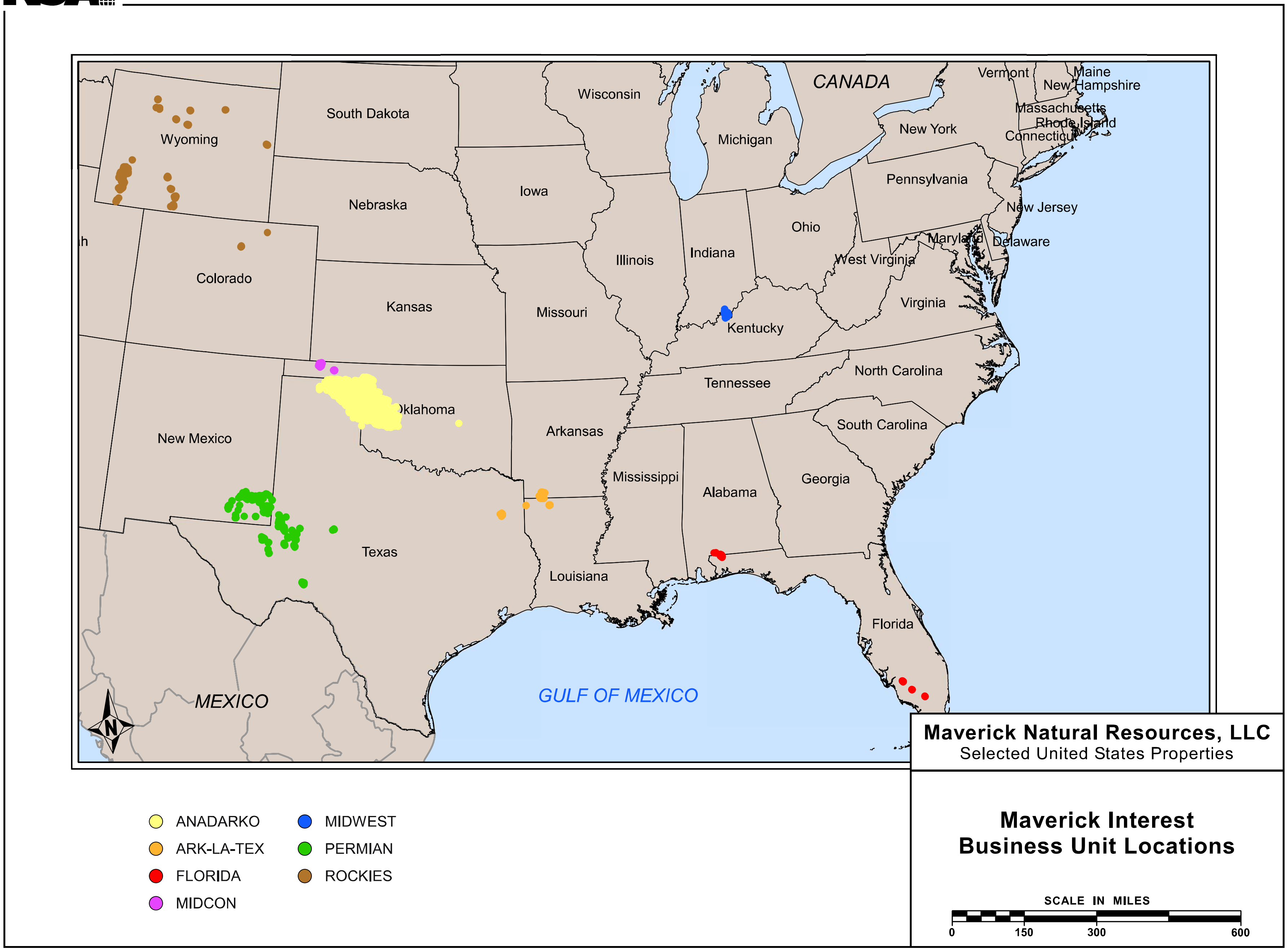
The gross number of wells and Maverick's average net abandonment cost per well, by business unit, are shown in the following table:

Business Unit	Gross Number of Wells	Average Net Abandonment Cost Per Well ($)
Anadarko	7,656	29,913
Ark-La-Tex	165	77,727
Florida	64	984,133
MidCon	270	158,431
MidWest	32	98,147
Permian	3,239	50,269
Rockies	786	81,837

We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

9.0 RECONCILIATIONS WITH PREVIOUS NSAI ESTIMATES

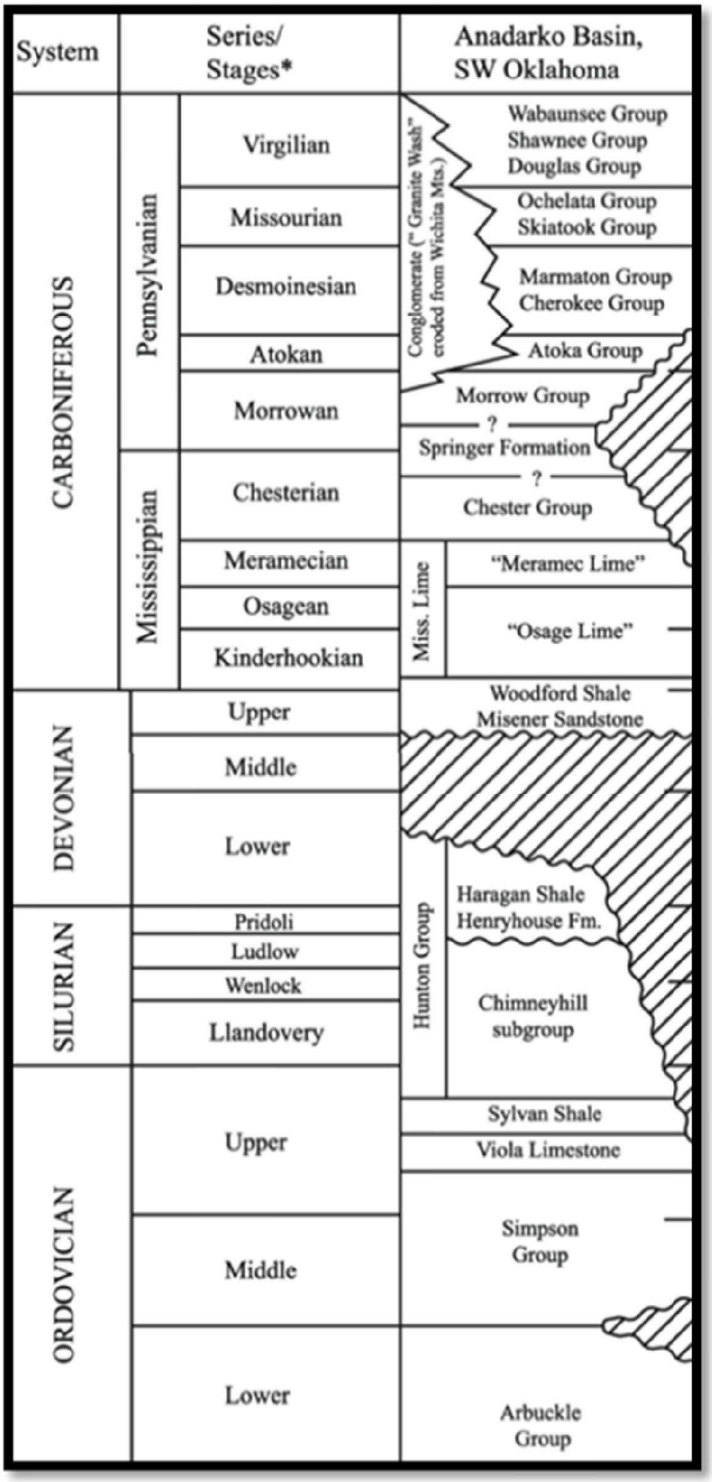
NSAI has not previously prepared a report covering these properties for DEC; as such, there is no reconciliation with previous reports issued for DEC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

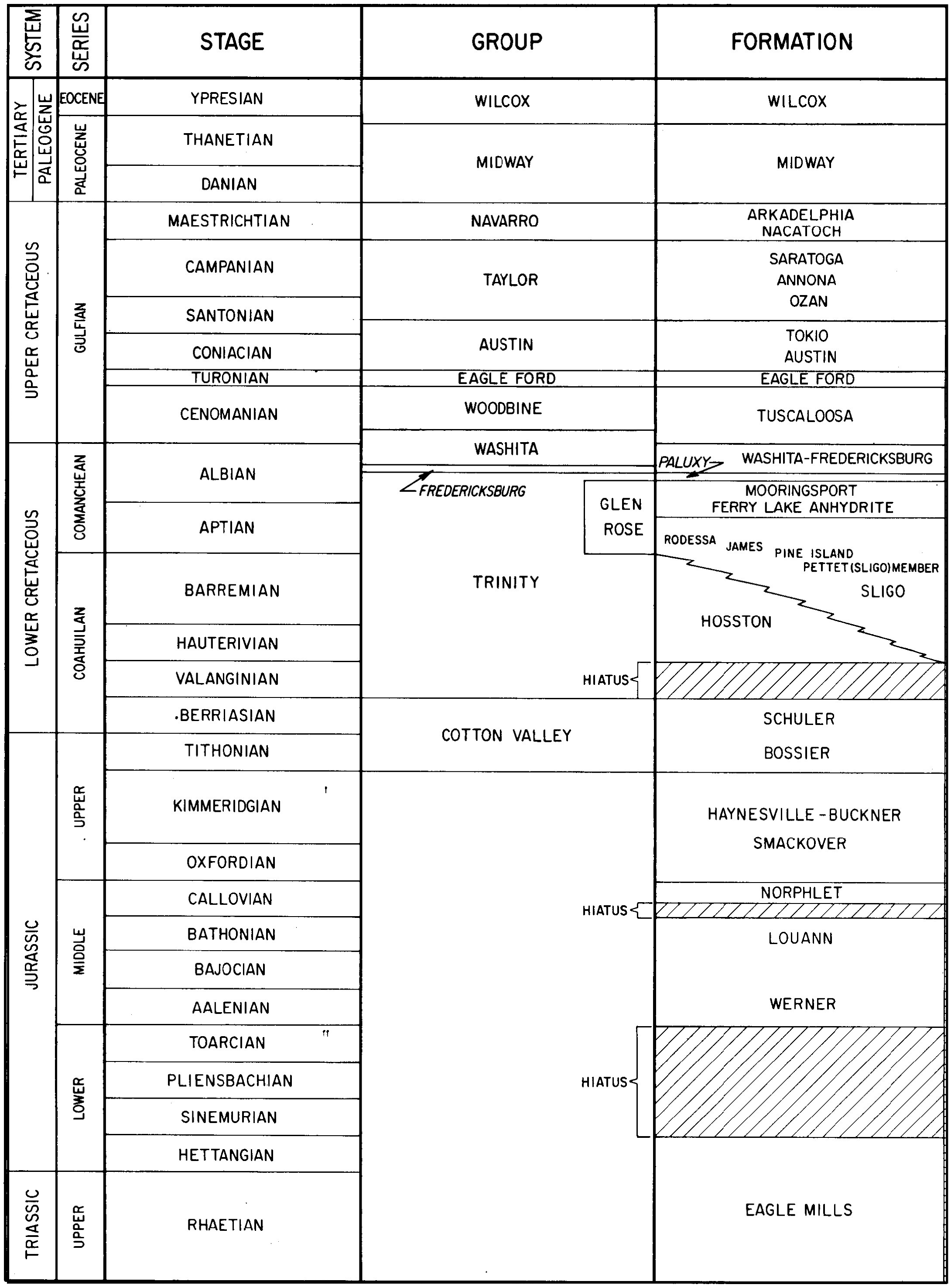
Figure 1

Stratigraphic Column
Anadarko Basin
Oklahoma and Texas



Modified from Johnson and Cardott (1992).

Stratigraphic Column
Ark-La-Tex Region
Arkansas, Louisiana, and Texas



Modified from Todd and Mitchum (1997), Seni and Jackson (1984), and Salvador (1985).

Stratigraphic Column
South Alabama and Florida Panhandle

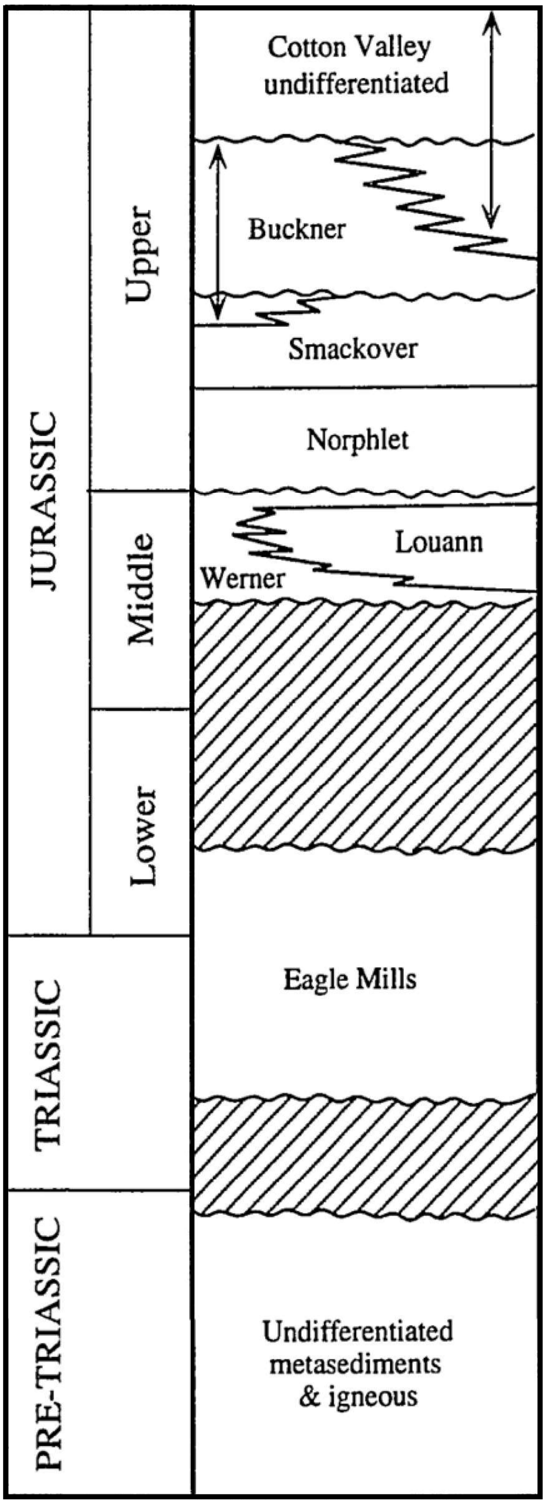


Figure provided by Maverick Natural Resources, LLC.

Stratigraphic Column
South Florida

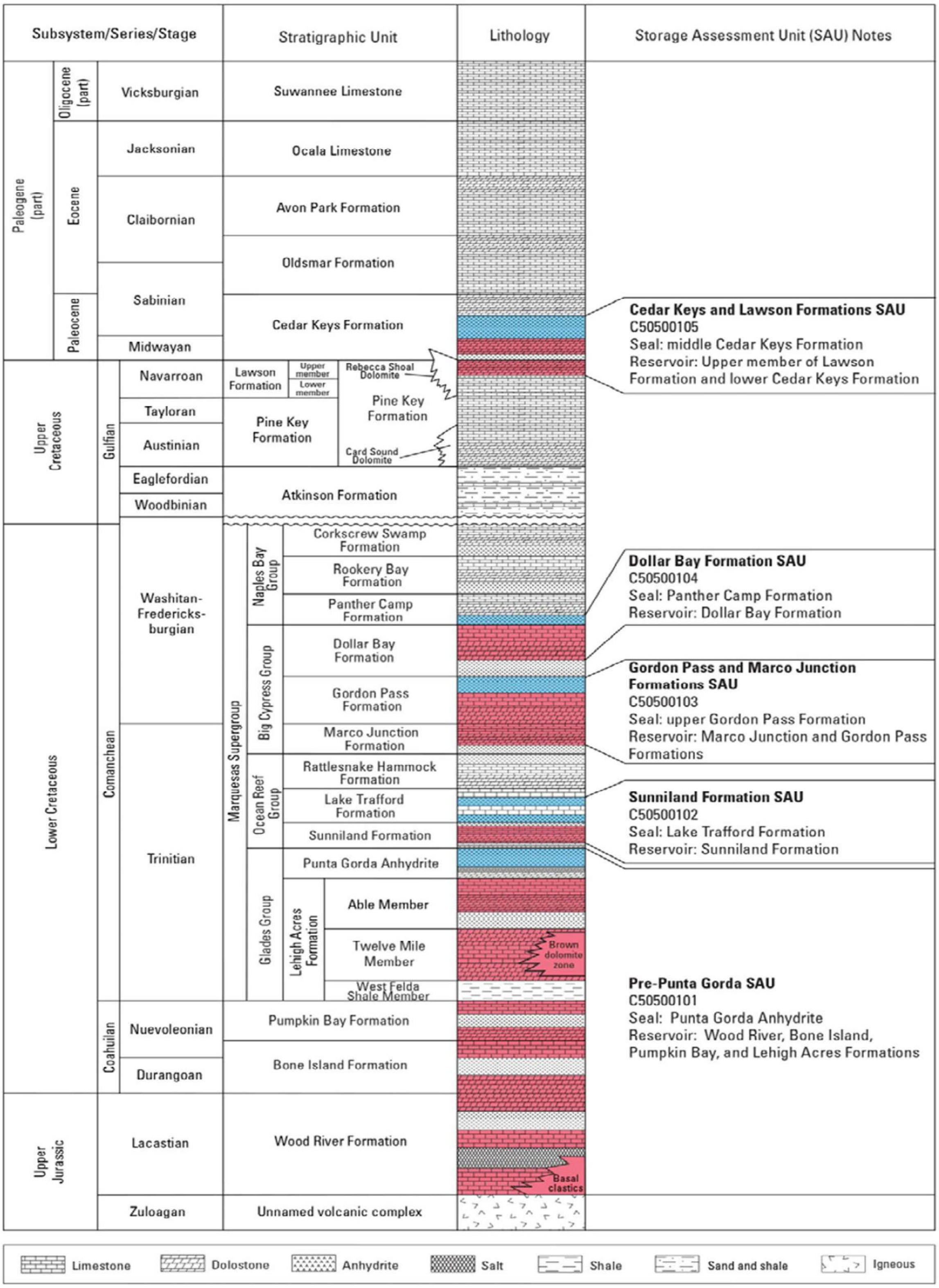


Figure provided by Maverick Natural Resources, LLC.

Stratigraphic Column
Oklahoma Basins

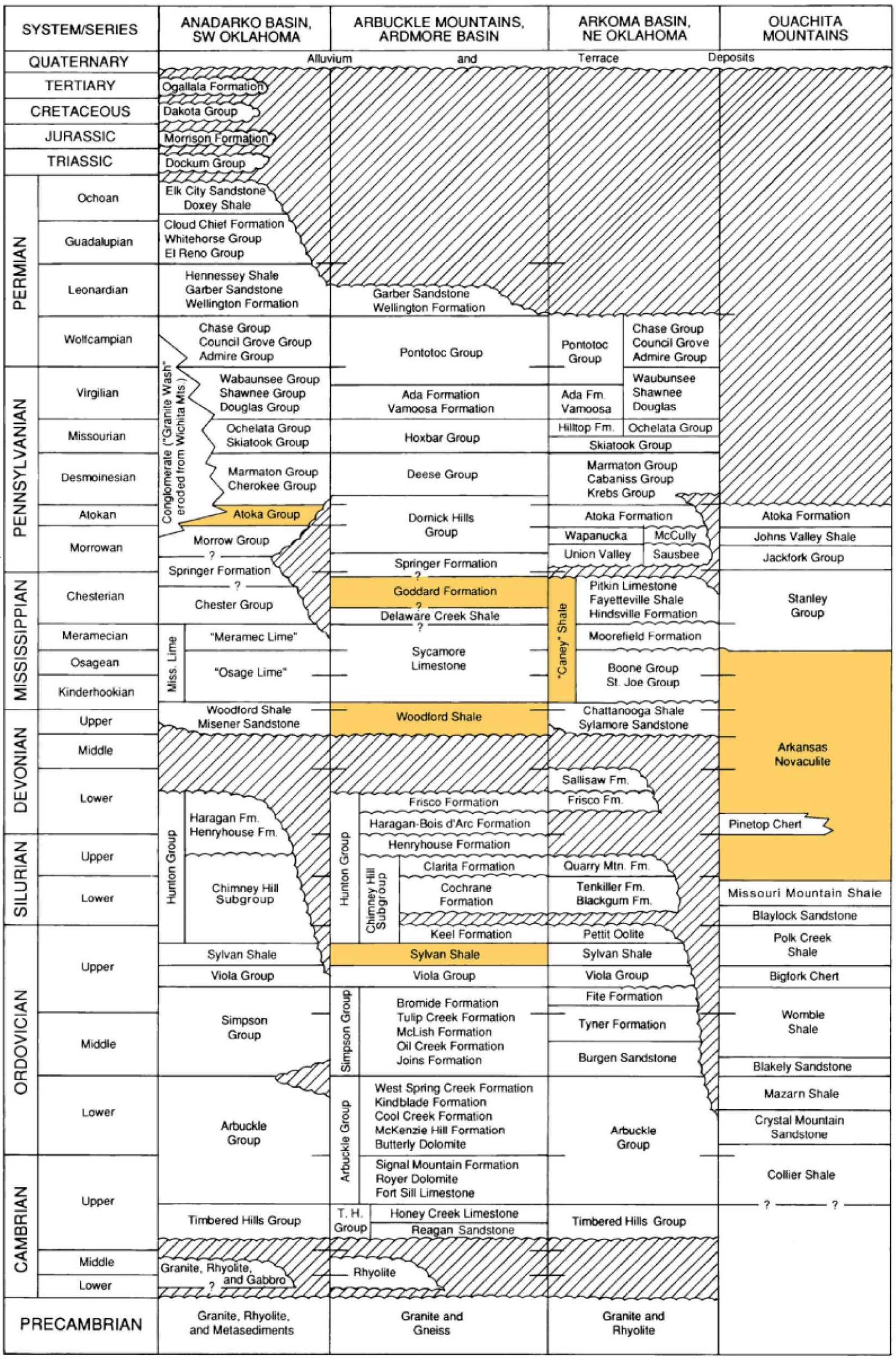
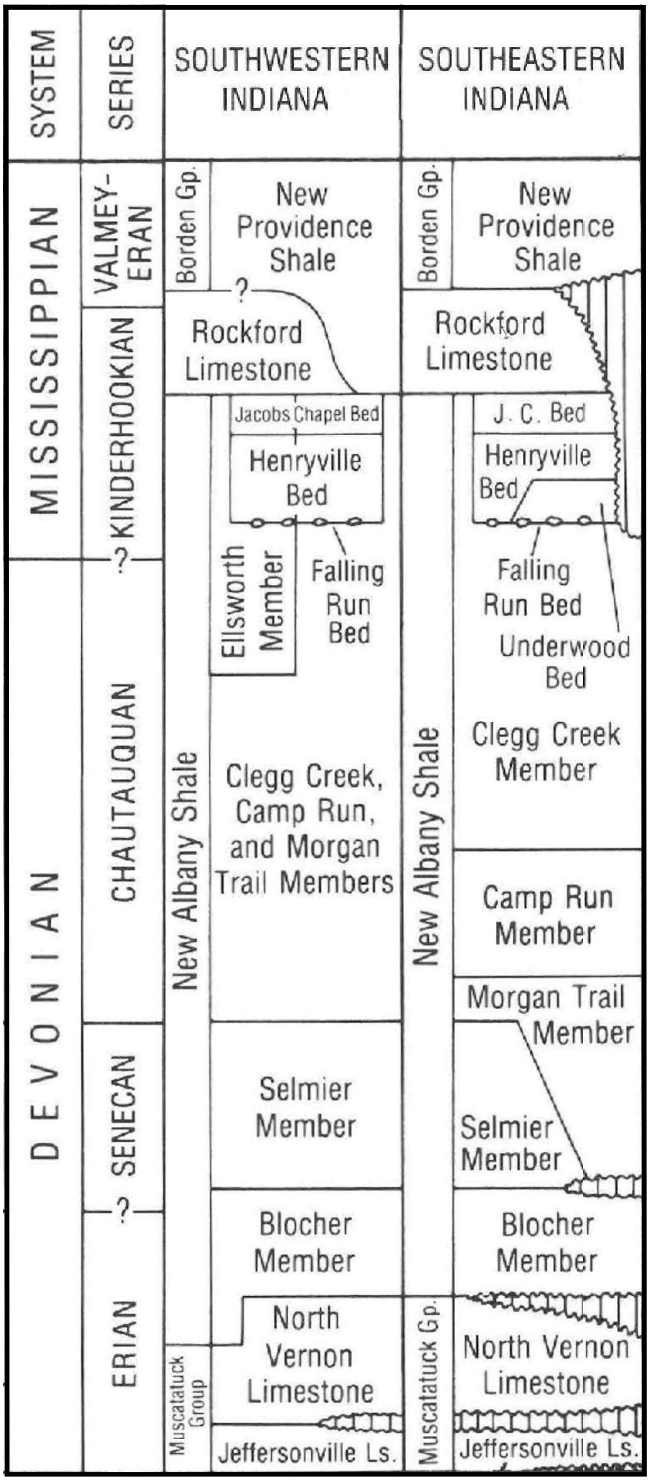


Figure provided by Maverick Natural Resources, LLC.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Stratigraphic Column
Illinois Basin
Southern Indiana



Adapted from U.S. Geological Survey Bulletin 2137, Figure 2.

Stratigraphic Column
Permian Basin
New Mexico and Texas

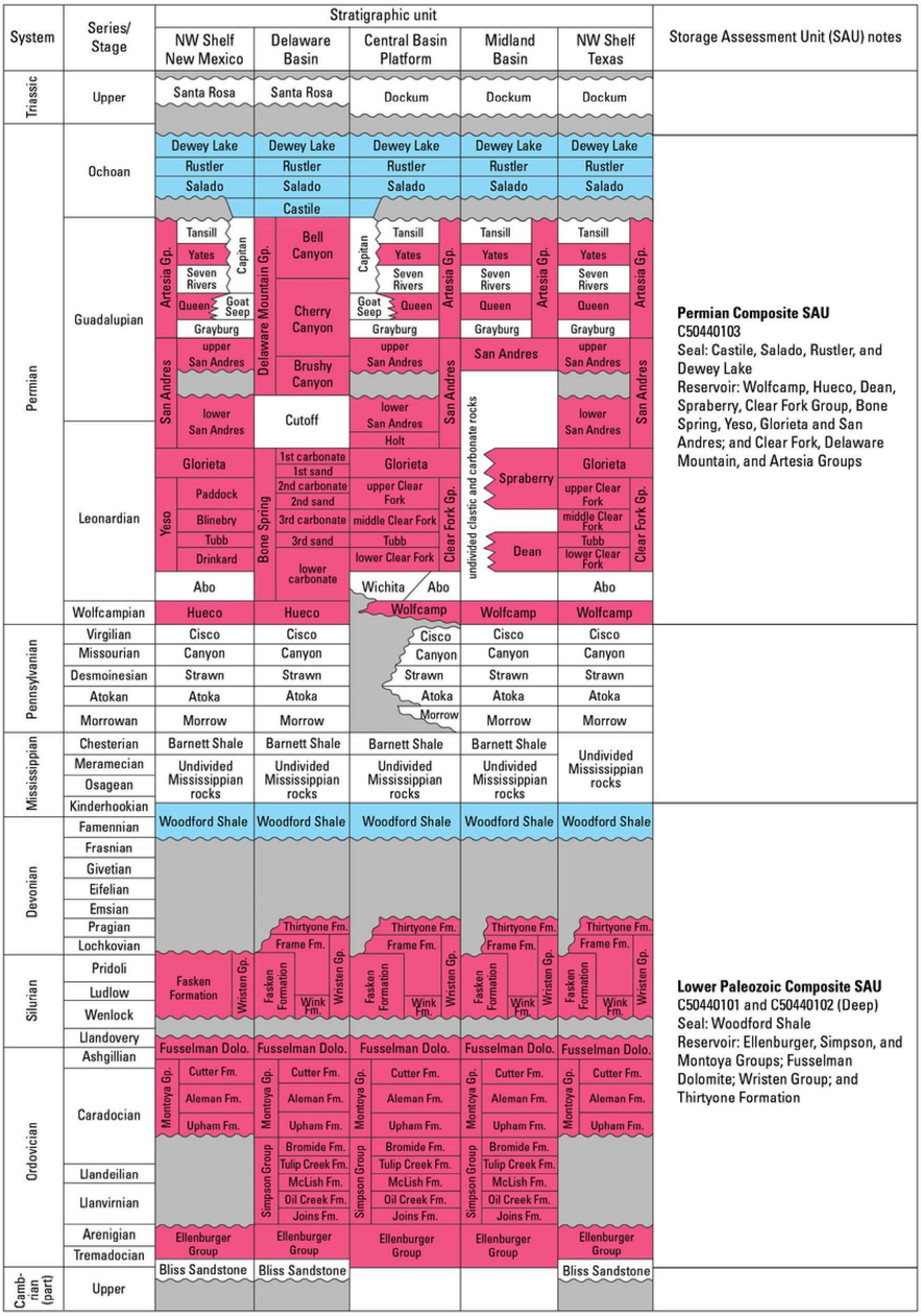


Figure provided by Maverick Natural Resources, LLC.

Stratigraphic Column
Big Horn Basin
Montana and Wyoming

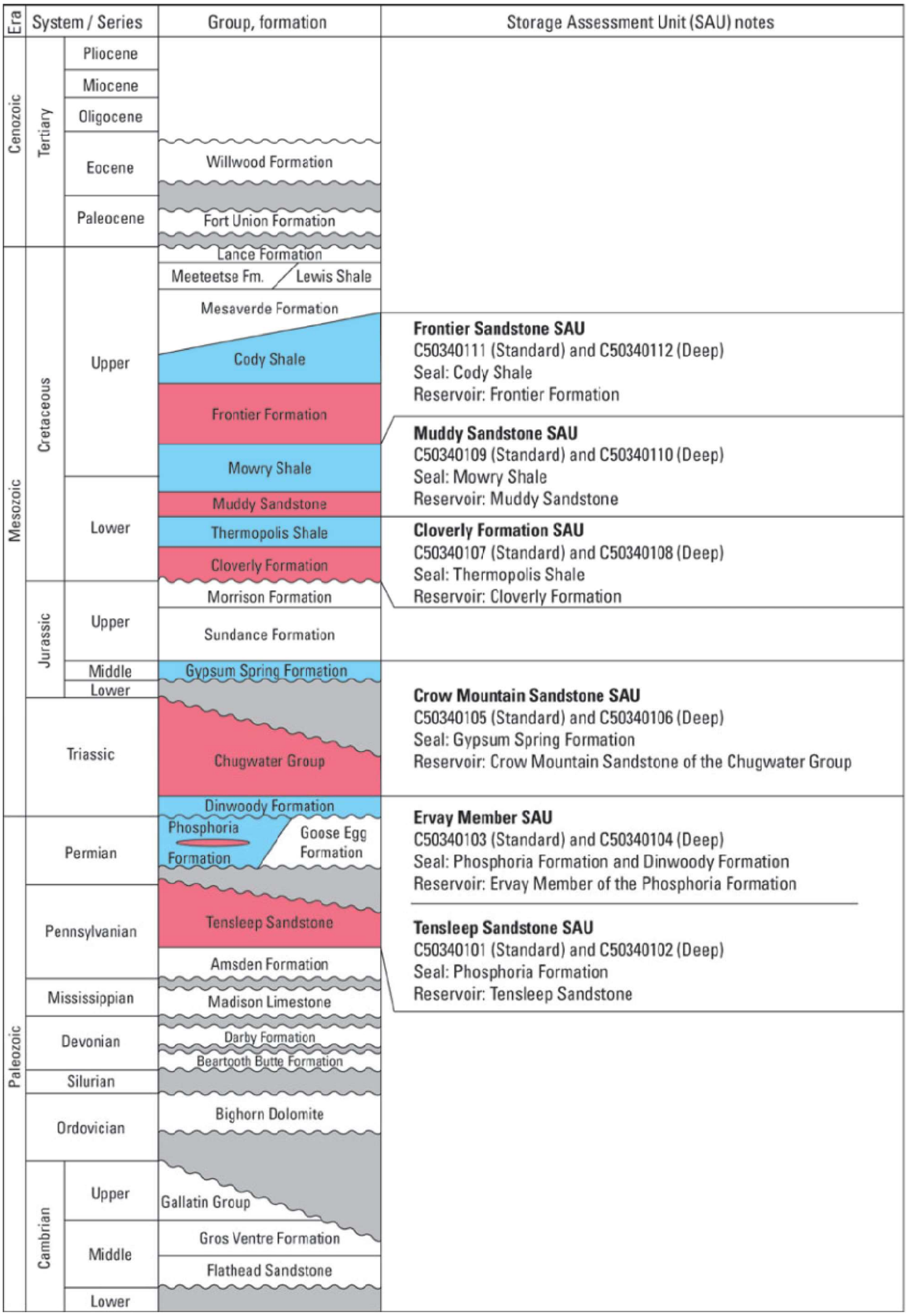


Figure provided by Maverick Natural Resources, LLC.

Stratigraphic Column
Green River Formation
Colorado, Utah, and Wyoming

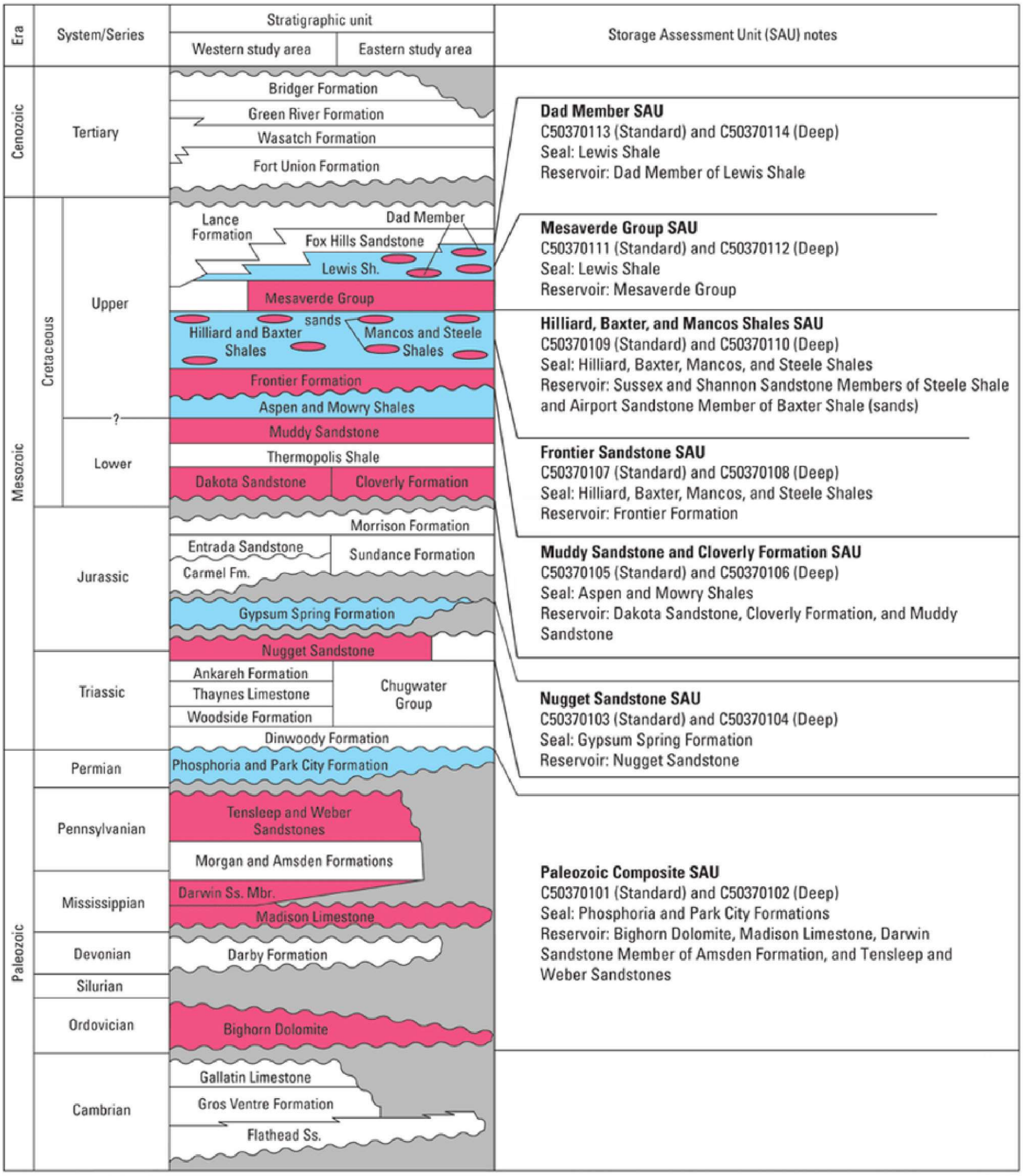


Figure provided by Maverick Natural Resources, LLC.

Stratigraphic Column
Powder River Basin
Montana and Wyoming

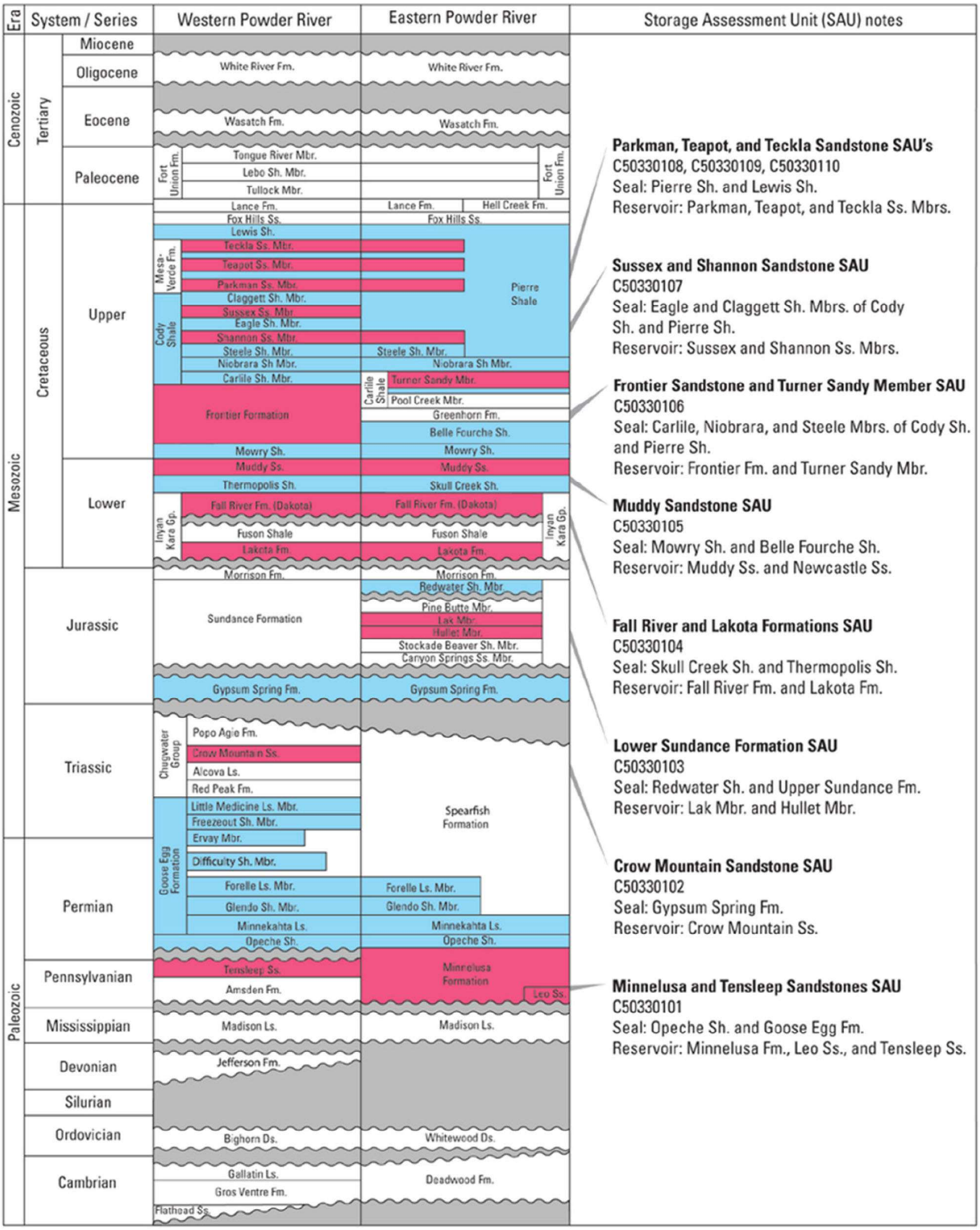
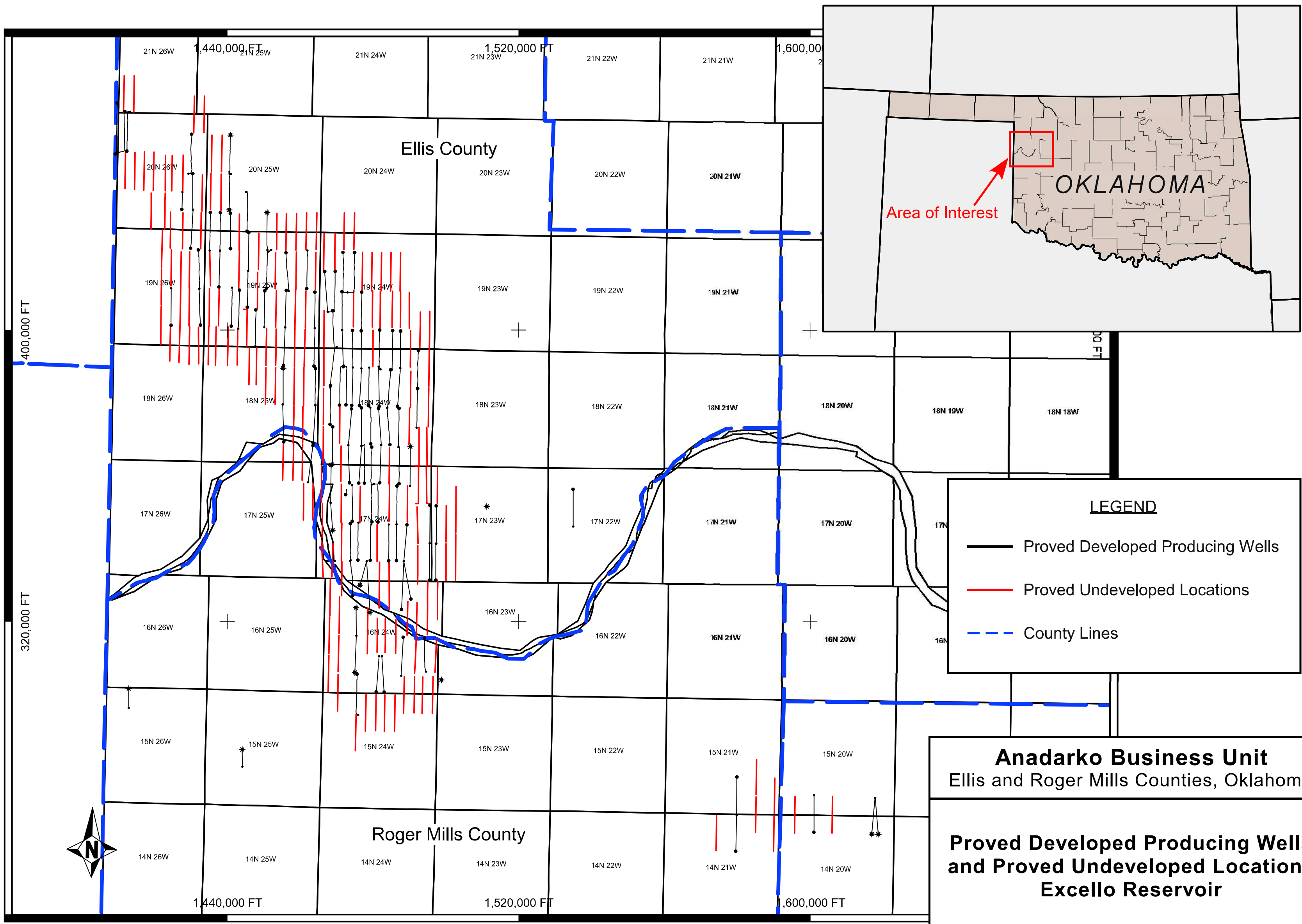


Figure provided by Maverick Natural Resources, LLC.

NETHERLAND, SEWELL & ASSOCIATES, INC.



Anadarko Business Unit
Ellis and Roger Mills Counties, Oklahoma

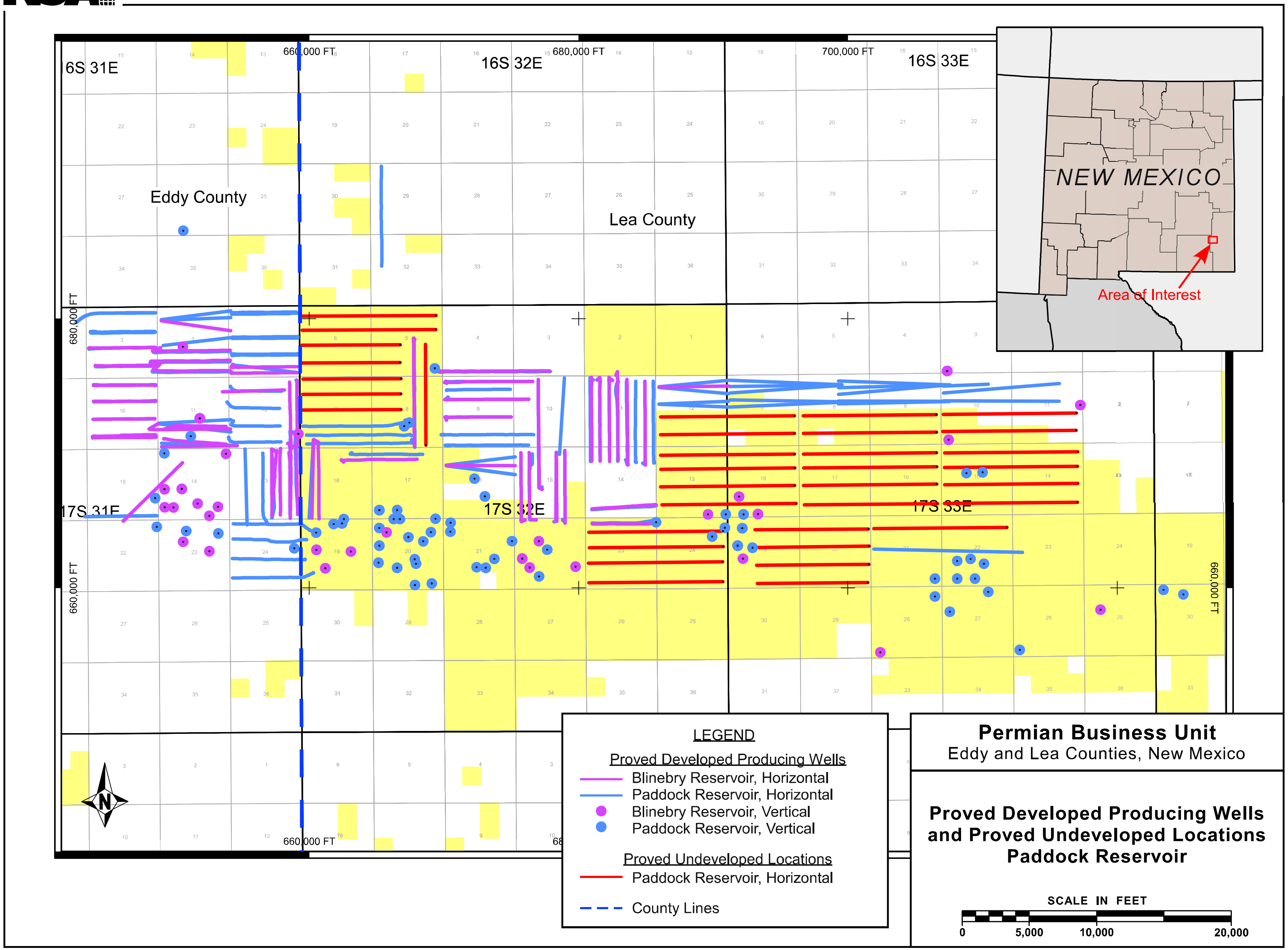
Proved Developed Producing Wells and Proved Undeveloped Locations Excello Reservoir

SCALE IN FEET
0 20,000 40,000 80,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 12

NETHERLAND, SEWELL & ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 13

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

TOTAL PROVED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	22,130.8	246,100.3	7,196.5	4,295.1	50,322.1	60.77	16.29	2.912	437,336.2	69,988.3	146,514.5	504.2	654,343.0
12-31-2026	25,064.0	248,916.0	9,147.4	4,294.2	52,519.4	58.25	15.51	3.264	532,859.8	66,589.8	171,442.6	441.6	771,333.8
12-31-2027	22,116.9	229,478.1	9,075.0	4,073.4	50,828.6	56.57	14.98	3.201	513,359.9	61,036.3	162,702.2	392.9	737,491.2
12-31-2028	19,595.0	215,329.0	7,563.5	3,683.6	47,828.4	55.46	14.71	3.132	419,478.9	54,192.7	149,786.9	326.9	623,785.3
12-31-2029	17,984.2	202,431.3	6,433.7	3,289.3	44,446.5	54.71	14.54	3.071	351,984.7	47,838.4	136,498.6	300.4	536,622.1
12-31-2030	13,952.9	181,306.6	5,144.3	2,955.2	39,386.3	54.54	14.55	3.070	280,591.1	43,006.9	120,909.3	271.8	444,779.1
12-31-2031	10,899.3	151,617.3	4,328.7	2,684.1	34,159.2	54.41	14.55	3.027	235,532.3	39,060.4	103,392.5	241.6	378,226.8
12-31-2032	9,126.5	128,090.7	3,801.4	2,451.8	30,478.2	54.32	14.56	3.005	206,509.2	35,688.4	91,578.8	219.2	333,995.6
12-31-2033	8,050.8	114,210.2	3,406.9	2,251.6	27,535.9	54.25	14.56	2.992	184,830.5	32,774.9	82,375.7	204.8	300,185.9
12-31-2034	7,165.7	103,078.6	3,048.0	2,076.2	25,111.7	54.24	14.56	2.983	165,333.0	30,220.7	74,897.4	191.2	270,642.2
12-31-2035	6,466.9	93,210.0	2,772.0	1,913.6	23,007.6	54.19	14.55	2.978	150,206.6	27,852.2	68,509.4	172.8	246,740.9
12-31-2036	5,873.4	84,860.4	2,531.7	1,767.5	21,171.6	54.15	14.55	2.975	137,091.6	25,721.6	62,981.5	161.8	225,956.5
12-31-2037	5,366.2	77,546.1	2,322.5	1,633.8	19,527.0	54.11	14.55	2.974	125,669.4	23,774.1	58,073.4	151.9	207,668.8
12-31-2038	4,915.6	70,777.3	2,134.0	1,507.7	17,991.8	54.07	14.55	2.975	115,383.8	21,934.2	53,519.0	136.1	190,973.2
12-31-2039	4,361.2	62,626.0	1,847.1	1,380.0	16,637.0	53.89	14.46	2.976	99,537.0	19,949.0	49,504.9	0.0	168,990.9
SUBTOTAL	183,069.5	2,209,578.0	70,752.6	40,257.2	500,951.3	55.91	14.89	3.060	3,955,703.8	599,627.9	1,532,686.6	3,717.1	6,091,734.0
REMAINING	44,150.8	606,059.0	18,873.6	12,943.0	168,969.6	53.37	14.39	3.032	1,007,233.0	186,218.1	512,396.7	0.0	1,705,847.9
TOTAL	227,220.3	2,815,637.0	89,626.2	53,200.2	669,920.8	55.37	14.77	3.053	4,962,936.8	785,846.0	2,045,083.3	3,717.1	7,797,581.8
CUM PROD	776,113.0	12,362,356.0											
ULTIMATE	1,003,333.0	15,177,992.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES: TAXES		CAPITAL	ABDNMNT	OPERATING	FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5,731	2,639.9	32,907.3	9,300.7	158,237.8	8,318.2	223,683.2	221,896.0	221,896.0	211,417.9
12-31-2026	5,172	2,451.1	39,907.4	10,918.9	354,792.0	8,260.9	222,598.6	134,856.1	356,752.1	323,622.6
12-31-2027	4,852	2,424.3	36,706.8	11,622.4	183,957.4	8,260.9	213,386.6	283,557.5	640,309.6	545,868.9
12-31-2028	4,619	2,271.2	30,549.0	9,535.0	109,062.8	8,260.9	191,134.3	275,243.5	915,553.0	743,298.0
12-31-2029	4,378	2,110.3	26,251.2	7,713.0	87,129.1	7,585.9	171,678.2	236,265.4	1,151,818.5	896,679.8
12-31-2030	4,193	2,019.1	21,481.9	6,682.0	14,476.2	7,510.9	155,503.0	239,125.0	1,390,943.5	1,038,616.5
12-31-2031	3,973	1,964.5	18,160.0	5,958.5	13,667.9	8,339.1	141,777.3	190,324.3	1,581,267.7	1,141,246.8
12-31-2032	3,754	1,926.5	15,980.1	5,395.5	12,988.4	7,466.8	130,563.7	161,601.1	1,742,868.9	1,220,446.6
12-31-2033	3,601	1,851.6	14,313.3	4,934.4	12,311.5	7,475.2	121,361.0	139,790.3	1,882,659.2	1,282,721.2
12-31-2034	3,462	1,767.1	12,906.1	4,481.8	11,560.9	8,169.6	111,539.1	121,984.8	2,004,644.1	1,332,120.1
12-31-2035	3,327	1,701.4	11,746.2	4,129.8	11,024.9	7,408.9	104,001.6	108,429.4	2,113,073.5	1,372,035.8
12-31-2036	3,168	1,619.9	10,728.6	3,815.4	10,534.3	7,191.3	97,173.7	96,513.1	2,209,586.7	1,404,334.1
12-31-2037	3,046	1,557.9	9,844.2	3,532.3	10,055.1	7,192.0	91,044.3	86,000.9	2,295,587.6	1,430,497.9
12-31-2038	2,904	1,484.4	9,047.7	3,268.0	8,469.6	11,118.9	85,160.2	73,908.7	2,369,496.3	1,450,940.4
12-31-2039	2,773	1,382.8	8,089.4	2,807.6	8,052.9	17,197.1	75,385.7	57,458.2	2,426,954.5	1,465,390.2
SUBTOTAL			298,619.0	94,095.2	1,006,320.6	129,756.4	2,135,990.4	2,426,954.5	2,426,954.5	1,465,390.2
REMAINING			81,854.8	29,894.9	133,480.4	447,402.8	863,103.6	150,110.8	2,577,064.7	1,526,738.7
TOTAL OF 50.0 YRS			380,473.9	123,990.1	1,139,801.1	577,159.3	2,999,094.0	2,577,065.2	2,577,064.7	1,526,738.7

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	1,685,604.4
12.000	1,392,777.2
15.000	1,228,427.4
20.000	1,023,747.3
25.000	875,952.5
30.000	764,800.1
35.000	678,513.0
40.000	609,825.1
45.000	554,020.0
50.000	507,906.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 14

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	17,952.5	230,805.8	6,243.4	4,254.9	47,792.4	60.66	16.27	2.867	378,704.9	69,237.0	137,039.4	504.2	585,485.4
12-31-2026	13,153.8	196,664.6	5,060.5	3,841.5	41,502.4	57.62	15.53	3.162	291,564.8	59,666.3	131,237.2	441.6	482,910.0
12-31-2027	10,762.4	171,472.6	4,412.4	3,458.1	36,835.4	55.85	15.12	3.087	246,446.2	52,281.1	113,716.5	392.9	412,836.6
12-31-2028	9,351.2	150,358.2	3,915.6	3,139.6	33,161.6	54.78	14.86	2.976	214,492.4	46,649.3	98,701.2	326.9	360,170.0
12-31-2029	8,302.4	132,837.2	3,529.9	2,853.2	29,975.2	54.03	14.69	2.842	190,710.5	41,903.5	85,181.6	300.4	318,096.1
12-31-2030	7,421.9	119,501.5	3,207.3	2,623.7	27,485.5	53.94	14.68	2.839	172,996.8	38,516.6	78,018.7	271.8	289,803.9
12-31-2031	6,557.3	106,682.3	2,925.2	2,418.3	25,286.0	53.87	14.67	2.836	157,587.4	35,476.3	71,711.4	241.6	265,016.7
12-31-2032	5,748.0	92,337.5	2,679.3	2,229.2	23,324.6	53.82	14.67	2.836	144,199.1	32,695.8	66,158.8	219.2	243,272.8
12-31-2033	5,265.1	84,378.1	2,469.2	2,059.7	21,518.8	53.77	14.66	2.837	132,767.1	30,201.5	61,055.4	204.8	224,228.7
12-31-2034	4,789.8	77,424.7	2,242.3	1,907.3	19,909.5	53.78	14.66	2.838	120,601.8	27,961.1	56,500.0	191.2	205,254.0
12-31-2035	4,392.8	70,674.6	2,065.8	1,762.6	18,421.1	53.73	14.66	2.840	111,006.4	25,836.6	52,311.9	172.8	189,327.6
12-31-2036	4,032.6	64,751.8	1,903.5	1,631.0	17,067.4	53.70	14.65	2.842	102,227.2	23,901.6	48,502.3	161.8	174,792.9
12-31-2037	3,711.5	59,383.2	1,757.2	1,509.1	15,811.8	53.66	14.65	2.845	94,300.3	22,114.4	44,977.0	151.9	161,543.6
12-31-2038	3,413.7	54,213.9	1,620.9	1,393.0	14,598.5	53.62	14.65	2.847	86,911.6	20,411.0	41,564.2	136.1	149,022.8
12-31-2039	2,987.4	47,405.5	1,378.3	1,274.2	13,516.4	53.35	14.56	2.849	73,524.5	18,546.7	38,513.3	0.0	130,584.4
SUBTOTAL	107,842.4	1,658,891.5	45,410.8	36,355.5	386,206.6	55.45	15.00	2.913	2,518,040.8	545,398.8	1,125,189.1	3,717.1	4,192,345.9
REMAINING	28,547.6	423,791.4	13,764.4	11,594.3	131,228.3	52.54	14.54	2.896	723,182.3	168,582.3	380,002.4	0.0	1,271,767.3
TOTAL	136,390.0	2,082,682.9	59,175.2	47,949.8	517,434.9	54.77	14.89	2.909	3,241,223.2	713,981.1	1,505,191.6	3,717.1	5,464,113.2
CUM PROD	776,092.9	12,360,285.0											
ULTIMATE	912,482.9	14,442,968.0											

			NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
PERIOD	NUMBER OF		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5,683	2,645.1	28,314.5	9,003.0	20,289.2	8,318.2	217,011.7	302,548.9	302,548.9	289,354.6
12-31-2026	5,041	2,371.7	22,704.3	7,972.3	19,119.0	8,260.9	189,864.7	234,988.9	537,537.8	493,432.4
12-31-2027	4,670	2,259.8	19,306.2	7,034.6	17,763.4	8,260.9	171,185.9	189,286.0	726,823.8	642,833.0
12-31-2028	4,398	2,133.0	16,841.9	6,247.8	16,520.4	8,260.9	155,007.6	157,291.3	884,115.1	755,681.0
12-31-2029	4,109	2,003.8	14,881.6	5,628.7	15,447.8	7,585.9	141,820.3	132,732.6	1,016,847.7	842,247.6
12-31-2030	3,922	1,927.4	13,532.5	5,207.7	14,392.0	7,510.9	131,328.7	117,831.9	1,134,679.7	912,106.1
12-31-2031	3,703	1,870.3	12,365.7	4,811.6	13,667.9	8,339.1	121,622.0	104,210.6	1,238,890.2	968,271.5
12-31-2032	3,484	1,838.8	11,337.0	4,456.2	12,988.4	7,466.8	112,949.3	94,075.1	1,332,965.4	1,014,363.8
12-31-2033	3,331	1,763.3	10,426.6	4,139.6	12,311.5	7,466.8	105,527.0	84,357.1	1,417,322.5	1,051,937.5
12-31-2034	3,193	1,678.5	9,561.4	3,793.3	11,560.9	8,169.6	97,020.6	75,148.1	1,492,470.7	1,082,366.8
12-31-2035	3,058	1,614.3	8,810.7	3,523.2	11,024.9	7,408.9	90,493.3	68,066.6	1,560,537.3	1,107,423.2
12-31-2036	2,899	1,533.5	8,114.0	3,273.3	10,534.3	7,191.3	84,468.5	61,211.2	1,621,748.6	1,127,907.8
12-31-2037	2,777	1,472.8	7,488.6	3,042.7	10,055.1	7,192.0	78,994.5	54,770.6	1,676,519.2	1,144,571.5
12-31-2038	2,635	1,400.3	6,906.8	2,822.1	8,469.6	11,050.1	73,662.8	46,111.4	1,722,630.5	1,157,326.7
12-31-2039	2,505	1,299.3	6,130.7	2,399.0	8,052.9	17,197.1	64,367.6	32,437.1	1,755,067.6	1,165,486.7
SUBTOTAL			196,722.5	73,355.0	202,197.1	129,679.3	1,835,324.7	1,755,067.6	1,755,067.6	1,165,486.7
REMAINING			59,986.0	25,563.6	133,480.4	440,637.0	678,287.3	-66,187.7	1,688,879.9	1,197,660.7
TOTAL OF 50.0 YRS			256,708.6	98,918.6	335,677.6	570,316.3	2,513,612.0	1,688,880.0	1,688,879.9	1,197,660.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	1,291,945.2
12.000	1,116,605.8
15.000	1,015,548.9
20.000	887,240.3
25.000	792,535.0
30.000	719,743.9
35.000	661,964.0
40.000	614,911.7
45.000	575,795.9
50.000	542,720.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 15

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED NON-PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	954.3	1,207.9	91.1	10.7	81.5	59.62	18.15	2.224	5,432.6	193.9	181.3	0.0	5,807.8
12-31-2026	479.4	703.9	65.1	7.1	55.7	54.15	17.04	2.641	3,525.9	120.4	147.2	0.0	3,793.4
12-31-2027	301.9	445.0	47.0	4.6	36.1	51.44	16.54	2.591	2,415.0	75.9	93.6	0.0	2,584.6
12-31-2028	221.4	324.2	37.3	3.4	27.1	49.79	16.22	2.501	1,855.0	55.8	67.8	0.0	1,978.7
12-31-2029	175.2	254.3	30.7	2.8	21.9	48.56	15.99	2.382	1,490.5	44.2	52.1	0.0	1,586.8
12-31-2030	144.2	246.0	25.9	2.3	31.3	48.03	16.01	2.990	1,242.3	36.0	93.5	0.0	1,371.9
12-31-2031	122.7	210.7	22.6	1.9	27.5	47.73	16.00	3.019	1,079.5	30.8	83.1	0.0	1,193.3
12-31-2032	107.0	184.6	20.3	1.7	24.8	47.58	15.97	3.038	966.7	27.1	75.4	0.0	1,069.2
12-31-2033	94.9	164.1	18.5	1.5	22.6	47.47	15.94	3.052	876.3	24.2	69.0	0.0	969.4
12-31-2034	85.2	147.6	16.9	1.4	20.4	47.38	15.92	3.052	801.9	21.9	62.2	0.0	886.1
12-31-2035	77.4	133.8	15.6	1.3	18.2	47.32	15.89	3.035	739.6	20.0	55.2	0.0	814.8
12-31-2036	70.8	122.2	14.5	1.2	16.8	47.27	15.87	3.040	686.6	18.5	51.2	0.0	756.3
12-31-2037	65.3	112.1	13.6	1.1	15.7	47.23	15.85	3.044	640.9	17.2	47.7	0.0	705.7
12-31-2038	60.3	101.5	12.6	0.9	13.6	47.10	16.01	3.075	591.9	14.0	41.7	0.0	647.6
12-31-2039	55.7	88.8	11.4	0.4	9.9	46.82	17.03	3.190	535.5	7.6	31.6	0.0	574.7
SUBTOTAL	3,015.6	4,446.8	443.0	42.1	423.1	51.64	16.79	2.724	22,880.3	707.4	1,152.6	0.0	24,740.3
REMAINING	614.1	1,057.1	104.1	5.4	130.1	50.46	17.03	3.270	5,255.5	92.2	425.4	0.0	5,773.2
TOTAL	3,629.7	5,504.0	547.2	47.5	553.2	51.42	16.82	2.852	28,135.8	799.7	1,578.0	0.0	30,513.5
CUM PROD	20.1	2,071.0											
ULTIMATE	3,649.8	7,575.0											

PERIOD	NUMBER OF		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	12	1.6	298.9	134.0	2,191.8	0.0	948.2	2,234.9	2,234.9	2,082.2
12-31-2026	12	2.5	195.8	111.5	0.0	0.0	930.6	2,555.4	4,790.4	4,306.8
12-31-2027	12	2.9	134.1	82.7	0.0	0.0	733.8	1,634.1	6,424.5	5,598.2
12-31-2028	12	3.1	103.1	66.8	0.0	0.0	620.9	1,187.8	7,612.3	6,451.4
12-31-2029	12	3.1	83.2	56.2	0.0	0.0	539.3	908.2	8,520.5	7,044.0
12-31-2030	14	3.5	73.0	50.0	84.2	0.0	447.1	717.5	9,238.0	7,467.1
12-31-2031	13	3.2	63.9	43.7	0.0	0.0	394.7	691.0	9,929.0	7,839.6
12-31-2032	13	3.2	57.3	39.6	0.0	0.0	366.2	606.0	10,535.0	8,136.5
12-31-2033	13	3.2	52.0	36.2	0.0	0.0	342.7	538.5	11,073.5	8,376.3
12-31-2034	13	3.2	47.6	33.2	0.0	0.0	322.2	483.1	11,556.7	8,571.9
12-31-2035	13	3.2	43.7	30.6	0.0	0.0	303.7	436.8	11,993.5	8,732.6
12-31-2036	13	3.2	40.6	28.5	0.0	0.0	289.2	398.0	12,391.4	8,865.8
12-31-2037	13	3.2	37.9	26.6	0.0	0.0	276.6	364.6	12,756.0	8,976.7
12-31-2038	13	3.1	34.8	24.9	0.0	68.8	259.6	259.4	13,015.5	9,048.9
12-31-2039	12	2.7	30.9	23.4	0.0	0.0	235.2	285.2	13,300.7	9,120.6
SUBTOTAL			1,296.8	787.9	2,276.0	68.8	7,010.1	13,300.7	13,300.7	9,120.6
REMAINING			291.4	178.2	0.0	3.7	1,997.0	3,302.8	16,603.5	9,501.3
TOTAL OF 50.0 YRS			1,588.2	966.1	2,276.0	72.5	9,007.1	16,603.5	16,603.5	9,501.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	10,285.6
12.000	8,854.6
15.000	8,067.7
20.000	7,078.9
25.000	6,344.1
30.000	5,770.5
35.000	5,306.9
40.000	4,922.4
45.000	4,597.1
50.000	4,317.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 16

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED UNDEVELOPED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	3,224.1	14,086.7	862.0	29.6	2,448.2	61.72	18.86	3.796	53,198.6	557.4	9,293.7	0.0	63,049.8
12-31-2026	11,430.8	51,547.4	4,021.7	445.6	10,961.2	59.12	15.27	3.655	237,769.1	6,803.0	40,058.2	0.0	284,630.4
12-31-2027	11,052.7	57,560.5	4,615.6	610.7	13,957.1	57.31	14.21	3.503	264,498.7	8,679.3	48,892.1	0.0	322,070.0
12-31-2028	10,022.4	64,646.6	3,610.7	540.6	14,639.7	56.26	13.85	3.485	203,131.5	7,487.5	51,017.8	0.0	261,636.8
12-31-2029	9,506.6	69,339.7	2,873.1	433.3	14,449.4	55.61	13.59	3.548	159,783.6	5,890.7	51,264.9	0.0	216,939.2
12-31-2030	6,386.8	61,559.1	1,911.2	329.2	11,869.5	55.65	13.53	3.606	106,352.0	4,454.3	42,797.0	0.0	153,603.3
12-31-2031	4,219.4	44,724.3	1,380.9	263.8	8,845.7	55.66	13.47	3.572	76,865.4	3,553.3	31,598.1	0.0	112,016.8
12-31-2032	3,271.5	35,568.6	1,101.8	220.9	7,128.8	55.68	13.42	3.555	61,343.4	2,965.6	25,344.7	0.0	89,653.6
12-31-2033	2,690.8	29,668.0	919.2	190.4	5,994.5	55.68	13.39	3.545	51,187.1	2,549.2	21,251.4	0.0	74,987.8
12-31-2034	2,290.7	25,506.3	788.8	167.6	5,181.8	55.69	13.35	3.538	43,929.3	2,237.7	18,335.2	0.0	64,502.1
12-31-2035	1,996.7	22,401.6	690.6	149.7	4,568.3	55.69	13.33	3.534	38,460.6	1,995.5	16,142.3	0.0	56,598.4
12-31-2036	1,770.0	19,986.5	613.6	135.4	4,087.4	55.70	13.30	3.530	34,177.9	1,801.5	14,428.0	0.0	50,407.4
12-31-2037	1,589.3	18,050.8	551.7	123.7	3,699.6	55.70	13.28	3.527	30,728.3	1,642.6	13,048.7	0.0	45,419.5
12-31-2038	1,441.6	16,461.9	500.5	113.8	3,379.7	55.70	13.26	3.525	27,880.4	1,509.3	11,913.1	0.0	41,302.8
12-31-2039	1,318.1	15,131.7	457.4	105.3	3,110.7	55.70	13.25	3.523	25,477.0	1,394.8	10,960.0	0.0	37,831.8
SUBTOTAL	72,211.5	546,239.7	24,898.8	3,859.6	114,321.6	56.82	13.87	3.554	1,414,782.6	53,521.7	406,345.2	0.0	1,874,649.9
REMAINING	14,989.1	181,210.6	5,005.1	1,343.3	37,611.2	55.70	13.06	3.509	278,795.1	17,543.6	131,968.9	0.0	428,307.5
TOTAL	87,200.6	727,450.2	29,903.8	5,202.9	151,932.7	56.63	13.66	3.543	1,693,577.7	71,065.3	538,314.1	0.0	2,302,957.3
CUM PROD	0.0	0.0											
ULTIMATE	87,200.6	727,450.3											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES: TAXES		CAPITAL	ABDNMNT	OPERATING	FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	36	16.9	4,294.0	163.6	135,756.8	0.0	5,723.2	-82,887.9	-82,887.9	-80,018.9
12-31-2026	119	61.4	17,007.3	2,835.1	335,673.0	0.0	31,803.3	-102,688.2	-185,576.1	-174,116.7
12-31-2027	170	100.4	17,266.6	4,505.2	166,194.0	0.0	41,467.0	92,637.3	-92,938.7	-102,562.3
12-31-2028	209	111.3	13,603.9	3,220.3	92,542.4	0.0	35,505.7	116,764.3	23,825.6	-18,834.4
12-31-2029	257	119.1	11,286.4	2,028.2	71,681.3	0.0	29,318.6	102,624.7	126,450.3	47,388.2
12-31-2030	257	113.2	7,876.4	1,424.3	0.0	0.0	23,727.2	120,575.5	247,025.8	119,043.2
12-31-2031	257	114.6	5,730.4	1,103.2	0.0	0.0	19,760.6	85,422.7	332,448.5	165,135.7
12-31-2032	257	113.9	4,585.7	899.7	0.0	0.0	17,248.2	66,920.0	399,368.5	197,946.2
12-31-2033	257	112.9	3,834.6	758.7	0.0	8.4	15,491.3	54,894.8	454,263.3	222,407.3
12-31-2034	256	111.3	3,297.1	655.2	0.0	0.0	14,196.2	46,353.6	500,616.8	241,181.3
12-31-2035	256	110.1	2,891.8	576.1	0.0	0.0	13,204.5	39,926.0	540,542.8	255,880.0
12-31-2036	256	109.0	2,573.9	513.6	0.0	0.0	12,416.0	34,903.9	575,446.7	267,560.5
12-31-2037	256	107.9	2,317.7	463.0	0.0	0.0	11,773.1	30,865.7	606,312.4	276,949.8
12-31-2038	256	107.0	2,106.1	421.0	0.0	0.0	11,237.7	27,537.9	633,850.3	284,564.8
12-31-2039	256	106.1	1,927.8	385.2	0.0	0.0	10,783.0	24,735.9	658,586.2	290,782.8
SUBTOTAL			100,599.7	19,952.3	801,847.6	8.4	293,655.7	658,586.2	658,586.2	290,782.8
REMAINING			21,577.4	4,153.1	0.0	6,762.1	182,819.4	212,995.6	871,581.6	319,576.7
TOTAL OF 50.0 YRS			122,177.1	24,105.3	801,847.6	6,770.5	476,475.1	871,581.8	871,581.6	319,576.7

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	383,373.5
12.000	267,316.8
15.000	204,810.8
20.000	129,428.1
25.000	77,073.4
30.000	39,285.7
35.000	11,242.0
40.000	-10,009.1
45.000	-26,373.0
50.000	-39,131.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 17

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

TOTAL PROVED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	22,796.9	261,470.1	7,372.2	4,457.6	51,755.5	74.77	19.91	3.602	551,238.5	88,733.9	186,446.3	693.5	827,112.3
12-31-2026	26,171.3	263,695.1	9,458.3	4,461.2	53,970.4	71.60	18.95	4.031	677,215.2	84,556.5	217,541.9	610.5	979,924.2
12-31-2027	23,871.4	248,106.1	9,591.2	4,324.9	53,043.9	69.57	18.31	3.949	667,229.8	79,206.1	209,462.4	558.6	956,456.9
12-31-2028	21,988.6	251,230.2	8,437.8	4,232.7	54,141.0	68.29	18.00	3.858	576,240.5	76,200.0	208,890.7	481.5	861,812.6
12-31-2029	19,902.8	235,049.3	7,117.1	3,743.1	49,727.0	67.41	17.79	3.761	479,741.1	66,573.3	187,023.1	436.9	733,774.2
12-31-2030	15,364.2	208,266.1	5,653.0	3,329.2	43,403.5	67.26	17.80	3.758	380,223.6	59,243.7	163,098.4	393.6	602,959.3
12-31-2031	12,242.7	175,513.0	4,749.7	3,015.1	37,601.0	67.13	17.79	3.716	318,830.6	53,633.8	139,735.1	330.5	512,530.1
12-31-2032	10,553.6	154,373.0	4,174.7	2,758.7	33,564.7	67.03	17.79	3.694	279,833.9	49,072.0	123,971.3	293.5	453,170.6
12-31-2033	9,231.1	138,257.1	3,749.4	2,537.8	30,386.1	66.96	17.79	3.680	251,044.4	45,141.5	111,808.4	274.5	408,268.7
12-31-2034	8,199.6	125,208.7	3,403.8	2,343.0	27,745.8	66.89	17.78	3.670	227,673.9	41,670.5	101,823.7	256.0	371,424.0
12-31-2035	7,430.7	113,653.1	3,106.3	2,165.6	25,472.2	66.83	17.78	3.664	207,597.3	38,507.2	93,329.2	232.7	339,666.4
12-31-2036	6,722.0	102,915.3	2,835.7	2,000.6	23,457.2	66.78	17.77	3.661	189,359.4	35,556.7	85,877.9	206.8	311,000.8
12-31-2037	6,136.1	94,167.7	2,609.4	1,852.1	21,685.6	66.72	17.76	3.660	174,087.0	32,900.3	79,371.2	193.9	286,552.3
12-31-2038	5,655.5	86,598.3	2,413.8	1,717.1	20,076.7	66.66	17.76	3.659	160,915.0	30,498.7	73,468.6	182.2	265,064.5
12-31-2039	5,017.5	76,675.2	2,101.5	1,575.2	18,609.2	66.47	17.65	3.660	139,698.2	27,801.3	68,107.7	0.0	235,607.7
SUBTOTAL	201,284.1	2,535,178.5	76,773.8	44,513.6	544,639.7	68.79	18.18	3.764	5,280,928.3	809,295.5	2,049,955.7	5,145.2	8,145,324.5
REMAINING	52,895.5	753,972.0	23,000.4	16,494.7	204,930.9	65.90	17.59	3.707	1,515,747.1	290,224.1	759,596.8	0.0	2,565,568.0
TOTAL	254,179.6	3,289,150.5	99,774.3	61,008.4	749,570.7	68.12	18.02	3.748	6,796,675.1	1,099,520.0	2,809,552.4	5,145.2	10,710,892.5
CUM PROD	776,113.0	12,362,356.0											
ULTIMATE	1,030,292.0	15,651,506.0											

PERIOD	NUMBER OF		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	6,328	2,896.9	41,419.5	11,940.9	161,998.0	8,318.2	240,542.9	362,892.4	362,892.4	345,988.3
12-31-2026	6,306	2,946.5	50,394.5	14,183.3	375,309.0	8,260.9	241,478.8	290,298.2	653,190.5	592,773.2
12-31-2027	6,130	2,962.9	47,225.8	15,472.3	250,545.0	8,260.9	236,551.0	398,402.4	1,051,593.0	906,290.7
12-31-2028	5,498	2,677.8	41,620.1	13,274.5	171,488.3	8,260.9	222,619.4	404,550.7	1,456,143.6	1,195,454.3
12-31-2029	5,313	2,527.8	35,483.6	10,664.2	87,673.0	7,585.9	200,455.9	391,912.3	1,848,055.9	1,450,427.5
12-31-2030	5,158	2,446.7	28,856.3	9,116.2	14,476.2	7,510.9	182,362.4	360,637.3	2,208,693.2	1,664,454.9
12-31-2031	4,977	2,359.5	24,414.4	8,079.0	13,667.9	8,339.1	165,994.6	292,035.1	2,500,728.3	1,821,910.5
12-31-2032	4,806	2,272.9	21,522.6	7,314.9	12,988.4	7,466.8	153,278.4	250,599.7	2,751,328.0	1,944,713.2
12-31-2033	4,638	2,230.7	19,343.0	6,713.1	12,311.5	7,466.8	143,135.4	219,298.8	2,970,626.8	2,042,395.9
12-31-2034	4,372	2,133.7	17,561.3	6,199.5	11,560.9	8,178.0	134,145.1	193,779.8	3,164,406.8	2,120,859.3
12-31-2035	4,219	2,058.9	16,037.4	5,730.2	11,024.9	7,408.2	125,697.9	173,767.9	3,338,174.7	2,184,820.2
12-31-2036	4,053	1,986.1	14,677.0	5,282.9	10,534.3	7,191.3	117,074.9	156,240.4	3,494,415.1	2,237,099.3
12-31-2037	3,870	1,904.8	13,495.7	4,921.4	10,055.1	7,191.3	110,007.9	140,880.8	3,635,296.0	2,279,952.9
12-31-2038	3,734	1,838.0	12,466.1	4,597.4	8,469.6	11,118.9	103,927.0	124,485.3	3,759,781.4	2,314,378.0
12-31-2039	3,584	1,731.9	11,189.2	3,989.5	8,052.9	17,196.4	92,660.1	102,519.4	3,862,300.7	2,340,152.8
SUBTOTAL			395,706.2	127,479.1	1,160,154.6	129,754.4	2,469,931.8	3,862,300.7	3,862,300.7	2,340,152.8
REMAINING			121,971.0	46,235.2	133,480.4	449,383.5	1,169,723.3	644,774.2	4,507,075.6	2,461,415.2
TOTAL OF 50.0 YRS			517,677.2	173,714.3	1,293,635.1	579,137.9	3,639,654.9	4,507,075.1	4,507,075.6	2,461,415.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	2,726,030.6
12.000	2,242,097.7
15.000	1,976,682.2
20.000	1,650,379.0
25.000	1,416,933.6
30.000	1,242,191.2
35.000	1,106,847.7
40.000	999,186.9
45.000	911,687.7
50.000	839,311.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 18

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED PRODUCING RESERVES

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	18,618.6	246,175.5	6,419.0	4,417.4	49,225.8	74.67	19.88	3.559	479,282.7	87,815.6	175,185.3	693.5	742,977.2
12-31-2026	14,004.6	211,032.1	5,268.2	3,996.4	42,875.2	70.97	18.97	3.930	373,904.8	75,826.8	168,511.6	610.5	618,853.6
12-31-2027	11,919.3	187,581.4	4,643.6	3,642.5	38,430.2	68.87	18.45	3.837	319,783.7	67,206.8	147,467.5	558.6	535,016.7
12-31-2028	10,043.3	168,031.6	4,125.5	3,334.5	34,913.0	67.58	18.13	3.705	278,822.0	60,451.5	129,359.8	481.5	469,114.8
12-31-2029	8,963.0	150,237.0	3,720.4	3,063.6	31,854.1	66.70	17.91	3.539	248,131.1	54,867.7	112,718.6	436.9	416,154.3
12-31-2030	8,107.3	137,231.0	3,392.3	2,835.4	29,367.1	66.62	17.91	3.535	226,000.4	50,771.3	103,799.6	393.6	380,965.0
12-31-2031	7,366.5	123,760.6	3,092.0	2,624.5	27,128.6	66.54	17.89	3.532	205,732.4	46,951.6	95,807.1	330.5	348,821.6
12-31-2032	6,748.9	113,157.2	2,842.2	2,433.6	25,119.5	66.47	17.88	3.530	188,912.1	43,523.0	88,675.2	293.5	321,403.8
12-31-2033	6,088.6	103,835.5	2,631.7	2,258.5	23,279.8	66.41	17.88	3.530	174,778.8	40,382.3	82,174.4	274.5	297,610.0
12-31-2034	5,517.4	95,585.1	2,441.2	2,097.7	21,598.0	66.36	17.87	3.529	161,989.5	37,496.5	76,226.1	256.0	275,968.0
12-31-2035	5,090.0	87,616.4	2,261.7	1,946.6	20,047.7	66.31	17.87	3.530	149,969.3	34,785.8	70,768.7	232.7	255,756.5
12-31-2036	4,645.5	79,665.6	2,084.5	1,802.6	18,599.6	66.25	17.86	3.532	138,108.3	32,196.8	65,692.7	206.8	236,204.5
12-31-2037	4,271.1	73,152.5	1,934.2	1,671.3	17,285.1	66.19	17.85	3.535	128,022.6	29,836.2	61,098.3	193.9	219,151.0
12-31-2038	3,963.9	67,419.1	1,801.6	1,550.9	16,053.9	66.14	17.85	3.536	119,146.1	27,684.1	56,772.8	182.2	203,785.2
12-31-2039	3,471.5	59,036.7	1,542.9	1,421.6	14,905.8	65.84	17.73	3.538	101,589.2	25,204.4	52,742.3	0.0	179,536.3
SUBTOTAL	118,819.5	1,903,517.2	48,201.1	39,096.9	410,683.1	68.34	18.29	3.621	3,294,173.2	715,000.1	1,486,999.9	5,145.2	5,501,318.7
REMAINING	34,659.5	534,138.9	16,675.7	14,444.5	158,175.1	65.02	17.72	3.581	1,084,258.6	255,960.8	566,377.9	0.0	1,906,596.4
TOTAL	153,479.0	2,437,656.1	64,876.8	53,541.5	568,858.2	67.49	18.13	3.610	4,378,431.5	970,960.9	2,053,377.8	5,145.2	7,407,915.0
CUM PROD	776,092.9	12,360,285.0											
ULTIMATE	929,571.9	14,797,941.0											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS AND EXPENDITURES: TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE: UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	6,280	2,902.0	35,791.1	11,571.1	20,289.2	8,318.2	233,871.4	433,135.7	433,135.7	414,140.2
12-31-2026	6,171	2,857.3	28,957.8	10,361.4	19,119.0	8,260.9	207,640.3	344,514.7	777,650.4	713,285.1
12-31-2027	5,938	2,760.7	24,875.1	9,245.5	17,763.4	8,260.9	191,064.8	283,807.4	1,061,457.8	937,259.3
12-31-2028	5,238	2,495.3	21,787.4	8,248.4	16,520.4	8,260.9	174,389.6	239,909.0	1,301,366.8	1,109,360.6
12-31-2029	5,005	2,381.5	19,341.7	7,440.8	15,447.8	7,585.9	160,240.0	206,098.5	1,507,465.2	1,243,756.9
12-31-2030	4,848	2,305.2	17,666.5	6,897.5	14,392.0	7,510.9	149,307.5	185,190.4	1,692,655.6	1,353,535.6
12-31-2031	4,667	2,209.2	16,172.1	6,368.1	13,667.9	8,339.1	138,109.5	166,164.8	1,858,820.5	1,443,079.0
12-31-2032	4,496	2,123.9	14,884.7	5,920.1	12,988.4	7,466.8	128,979.4	151,164.6	2,009,985.0	1,517,132.2
12-31-2033	4,328	2,089.0	13,766.8	5,535.8	12,311.5	7,466.8	121,372.1	137,157.0	2,147,142.0	1,578,214.3
12-31-2034	4,062	1,998.0	12,751.8	5,181.2	11,560.9	8,169.6	114,288.3	124,016.8	2,271,158.8	1,628,423.7
12-31-2035	3,910	1,926.4	11,811.5	4,833.3	11,024.9	7,408.2	107,338.6	113,340.0	2,384,498.9	1,670,139.1
12-31-2036	3,744	1,857.7	10,912.1	4,483.1	10,534.3	7,191.3	99,940.0	103,143.7	2,487,642.6	1,704,650.2
12-31-2037	3,562	1,780.8	10,105.3	4,201.0	10,055.1	7,191.3	93,896.7	93,701.4	2,581,344.0	1,733,152.5
12-31-2038	3,426	1,716.7	9,386.7	3,941.2	8,469.6	11,050.1	88,661.2	82,276.1	2,663,620.1	1,755,905.5
12-31-2039	3,277	1,612.0	8,374.6	3,387.9	8,052.9	17,196.4	78,129.5	64,394.8	2,728,014.8	1,772,097.0
SUBTOTAL			256,585.1	97,616.4	202,197.1	129,677.3	2,087,229.2	2,728,014.8	2,728,014.8	1,772,097.0
REMAINING			89,329.4	39,301.9	133,480.4	440,639.0	913,068.9	290,777.1	3,018,791.7	1,847,281.9
TOTAL OF 50.0 YRS			345,914.5	136,918.3	335,677.6	570,316.3	3,000,298.0	3,018,791.9	3,018,791.7	1,847,281.9

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	2,012,150.4
12.000	1,709,633.7
15.000	1,542,013.2
20.000	1,334,189.8
25.000	1,183,773.3
30.000	1,069,658.8
35.000	979,935.9
40.000	907,400.6
45.000	847,443.4
50.000	796,985.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 19

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED DEVELOPED NON-PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	954.3	1,207.9	91.1	10.7	81.5	73.60	22.19	2.930	6,706.4	236.9	238.9	0.0	7,182.2
12-31-2026	479.4	703.9	65.1	7.1	55.7	67.49	20.83	3.423	4,394.4	147.1	190.8	0.0	4,732.3
12-31-2027	301.9	445.0	46.8	4.6	36.1	64.40	20.22	3.359	3,017.1	92.8	121.4	0.0	3,231.3
12-31-2028	221.4	324.2	36.5	3.4	27.1	62.40	19.83	3.247	2,275.9	68.2	88.1	0.0	2,432.2
12-31-2029	175.2	254.3	30.7	2.8	21.9	61.18	19.55	3.098	1,877.9	54.0	67.7	0.0	1,999.6
12-31-2030	145.5	247.4	26.7	2.3	32.3	60.91	19.50	3.698	1,629.2	45.3	119.4	0.0	1,793.8
12-31-2031	124.2	212.5	23.7	2.0	28.7	60.72	19.46	3.724	1,437.9	39.0	107.0	0.0	1,584.0
12-31-2032	108.4	186.2	21.3	1.8	25.9	60.58	19.42	3.742	1,289.2	34.4	97.0	0.0	1,420.6
12-31-2033	96.2	165.6	19.3	1.6	22.8	60.48	19.39	3.730	1,169.8	30.8	85.1	0.0	1,285.6
12-31-2034	86.4	148.9	17.7	1.4	20.7	60.39	19.36	3.731	1,070.7	27.9	77.1	0.0	1,175.7
12-31-2035	78.5	135.1	16.4	1.3	19.0	60.33	19.33	3.738	986.9	25.5	71.2	0.0	1,083.6
12-31-2036	71.4	122.9	14.9	1.2	17.3	60.12	19.35	3.748	896.8	23.2	64.9	0.0	984.9
12-31-2037	65.3	112.1	13.5	1.1	15.7	59.84	19.38	3.760	810.1	21.0	58.9	0.0	890.0
12-31-2038	60.3	101.5	12.6	0.9	13.6	59.72	19.57	3.791	750.1	17.1	51.4	0.0	818.7
12-31-2039	55.7	88.8	11.4	0.4	9.9	59.44	20.81	3.906	679.9	9.3	38.6	0.0	727.8
SUBTOTAL	3,023.9	4,456.3	447.8	42.6	428.3	64.74	20.49	3.450	28,992.3	872.5	1,477.5	0.0	31,342.3
REMAINING	674.1	1,101.7	131.5	5.7	132.3	61.03	20.81	3.966	8,025.1	118.8	524.9	0.0	8,668.8
TOTAL	3,698.0	5,558.0	579.3	48.3	560.6	63.90	20.53	3.572	37,017.4	991.4	2,002.4	0.0	40,011.1
CUM PROD	20.1	2,071.0											
ULTIMATE	3,718.1	7,629.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	12	1.6	369.7	168.5	2,191.8	0.0	948.2	3,504.1	3,504.1	3,289.2
12-31-2026	12	2.5	244.7	142.2	0.0	0.0	930.6	3,414.7	6,918.8	6,261.5
12-31-2027	12	2.9	168.1	106.0	0.0	0.0	732.3	2,224.9	9,143.7	8,019.8
12-31-2028	12	3.0	127.5	85.6	0.0	0.0	609.7	1,609.5	10,753.1	9,175.2
12-31-2029	12	3.1	105.1	72.5	0.0	0.0	539.3	1,282.7	12,035.8	10,012.1
12-31-2030	14	3.7	94.4	68.7	84.2	0.0	495.7	1,050.8	13,086.6	10,632.8
12-31-2031	14	3.8	83.5	61.6	0.0	0.0	455.3	983.6	14,070.1	11,162.9
12-31-2032	14	3.8	74.9	55.8	0.0	0.0	423.0	866.8	14,936.9	11,587.5
12-31-2033	14	3.8	67.8	50.8	0.0	0.0	394.6	772.4	15,709.3	11,931.5
12-31-2034	14	3.8	62.1	46.7	0.0	0.0	371.6	695.4	16,404.7	12,213.1
12-31-2035	14	3.8	57.2	43.3	0.0	0.0	352.3	630.9	17,035.6	12,445.2
12-31-2036	14	3.7	52.4	38.9	0.0	0.0	316.5	577.1	17,612.7	12,638.3
12-31-2037	13	3.2	47.9	34.4	0.0	0.0	275.9	531.7	18,144.4	12,800.0
12-31-2038	13	3.1	44.1	32.3	0.0	68.8	259.5	414.0	18,558.4	12,915.0
12-31-2039	12	2.7	39.3	30.3	0.0	0.0	235.2	423.1	18,981.5	13,021.3
SUBTOTAL			1,638.7	1,037.7	2,276.0	68.8	7,339.8	18,981.5	18,981.5	13,021.3
REMAINING			451.2	320.4	0.0	3.7	3,107.8	4,785.7	23,767.2	13,589.9
TOTAL OF 50.0 YRS			2,089.8	1,358.1	2,276.0	72.5	10,447.5	23,767.2	23,767.2	13,589.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	14,712.6
12.000	12,666.7
15.000	11,547.5
20.000	10,149.0
25.000	9,116.2
30.000	8,313.9
35.000	7,668.0
40.000	7,133.8
45.000	6,682.9
50.000	6,295.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 20

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2025

MAVERICK NATURAL RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN THE UNITED STATES

PROVED UNDEVELOPED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL/COND	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$	M$
12-31-2025	3,224.1	14,086.7	862.0	29.6	2,448.2	75.70	23.06	4.502	65,249.4	681.4	11,022.1	0.0	76,953.0
12-31-2026	11,687.3	51,959.1	4,125.1	457.8	11,039.5	72.46	18.75	4.424	298,916.1	8,582.7	48,839.6	0.0	356,338.3
12-31-2027	11,650.2	60,079.8	4,900.7	677.8	14,577.5	70.28	17.57	4.244	344,429.0	11,906.5	61,873.4	0.0	418,208.9
12-31-2028	11,723.8	82,874.4	4,275.8	894.8	19,200.8	69.03	17.52	4.137	295,142.6	15,680.4	79,442.8	0.0	390,265.6
12-31-2029	10,764.6	84,558.0	3,366.0	676.7	17,851.0	68.25	17.22	4.159	229,732.0	11,651.6	74,236.8	0.0	315,620.2
12-31-2030	7,111.4	70,787.6	2,234.0	491.5	14,004.2	68.31	17.15	4.226	152,594.0	8,427.1	59,179.3	0.0	220,200.4
12-31-2031	4,752.0	51,539.9	1,633.9	388.6	10,443.7	68.34	17.10	4.196	111,660.3	6,643.2	43,821.0	0.0	162,124.6
12-31-2032	3,696.3	41,029.7	1,311.2	323.3	8,419.3	68.36	17.06	4.181	89,632.5	5,514.6	35,199.1	0.0	130,346.2
12-31-2033	3,046.4	34,256.0	1,098.3	277.7	7,083.6	68.37	17.03	4.171	75,095.8	4,728.4	29,548.9	0.0	109,373.1
12-31-2034	2,595.8	29,474.6	944.9	243.9	6,127.2	68.38	17.00	4.165	64,613.7	4,146.1	25,520.6	0.0	94,280.4
12-31-2035	2,262.3	25,901.6	828.2	217.7	5,405.4	68.39	16.98	4.160	56,641.1	3,695.9	22,489.3	0.0	82,826.3
12-31-2036	2,005.1	23,126.9	736.2	196.8	4,840.3	68.39	16.96	4.157	50,354.4	3,336.7	20,120.3	0.0	73,811.5
12-31-2037	1,799.7	20,903.0	661.6	179.7	4,384.8	68.40	16.94	4.154	45,254.3	3,043.1	18,214.0	0.0	66,511.4
12-31-2038	1,631.3	19,077.7	599.7	165.3	4,009.2	68.40	16.92	4.151	41,018.8	2,797.5	16,644.3	0.0	60,460.7
12-31-2039	1,490.3	17,549.8	547.2	153.1	3,693.5	68.40	16.90	4.150	37,429.2	2,587.7	15,326.7	0.0	55,343.6
SUBTOTAL	79,440.6	627,204.7	28,124.9	5,374.1	133,528.3	69.61	17.38	4.205	1,957,763.1	93,422.8	561,478.3	0.0	2,612,664.1
REMAINING	17,561.9	218,731.3	6,193.2	2,044.5	46,623.5	68.38	16.70	4.133	423,463.4	34,144.6	192,693.9	0.0	650,302.0
TOTAL	97,002.5	845,936.0	34,318.2	7,418.6	180,151.8	69.39	17.20	4.186	2,381,226.5	127,567.4	754,172.3	0.0	3,262,966.0
CUM PROD	0.0	0.0											
ULTIMATE	97,002.5	845,936.2											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS AND EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	36	16.9	5,258.8	201.4	139,517.0	0.0	5,723.2	-73,747.5	-73,747.5	-71,441.1
12-31-2026	123	63.4	21,192.0	3,679.6	356,190.0	0.0	32,907.8	-57,631.2	-131,378.6	-126,773.3
12-31-2027	180	106.9	22,182.6	6,120.8	232,781.6	0.0	44,753.8	112,370.2	-19,008.4	-38,988.3
12-31-2028	248	133.3	19,705.2	4,940.5	154,967.9	0.0	47,620.1	163,032.1	144,023.7	76,918.5
12-31-2029	296	142.4	16,036.7	3,150.8	72,225.2	0.0	39,676.6	184,531.2	328,554.9	196,658.6
12-31-2030	296	140.5	11,095.3	2,149.9	0.0	0.0	32,559.1	174,396.2	502,951.0	300,286.6
12-31-2031	296	143.2	8,158.9	1,649.2	0.0	0.0	27,429.7	124,886.7	627,837.8	367,668.7
12-31-2032	296	142.8	6,563.0	1,339.0	0.0	0.0	23,876.0	98,568.3	726,406.1	415,993.6
12-31-2033	296	141.5	5,508.3	1,126.5	0.0	0.0	21,368.8	81,369.4	807,775.5	452,250.2
12-31-2034	296	140.2	4,747.4	971.7	0.0	8.4	19,485.2	69,067.6	876,843.1	480,222.7
12-31-2035	295	138.3	4,168.7	853.7	0.0	0.0	18,007.0	59,797.0	936,640.1	502,236.0
12-31-2036	295	136.8	3,712.5	760.9	0.0	0.0	16,818.5	52,519.6	989,159.7	519,810.9
12-31-2037	295	135.2	3,342.4	686.0	0.0	0.0	15,835.3	46,647.7	1,035,807.5	534,000.6
12-31-2038	295	133.7	3,035.3	623.9	0.0	0.0	15,006.2	41,795.3	1,077,602.8	545,557.8
12-31-2039	295	132.3	2,775.4	571.2	0.0	0.0	14,295.5	37,701.5	1,115,304.3	555,034.8
SUBTOTAL			137,482.5	28,825.1	955,681.8	8.4	375,362.8	1,115,304.3	1,115,304.3	555,034.8
REMAINING			32,190.4	6,612.9	0.0	8,740.7	253,546.4	349,211.5	1,464,515.7	600,543.6
TOTAL OF 50.0 YRS			169,672.9	35,438.0	955,681.8	8,749.1	628,909.1	1,464,515.8	1,464,515.7	600,543.6

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	699,167.6
12.000	519,797.2
15.000	423,121.6
20.000	306,040.3
25.000	224,044.2
30.000	164,218.5
35.000	119,243.9
40.000	84,652.4
45.000	57,561.4
50.000	36,030.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON DEC PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 21

CONFIRMATIONS

In accordance with your instructions, Netherland, Sewell & Associates, Inc. (NSAI) hereby confirms that:

(a) NSAI consents to the inclusion of the Competent Person's Report (report), and/or extracts therefrom, in this document and the reference thereto and to its name in this document;

(b) NSAI accepts responsibility, for the purposes of paragraph 5.3.2(R)(2)(f) of the Prospectus Regulation Rules, for the CPR set out in Part 5 of the Prospectus and for any information sourced from the CPR in the Prospectus. In accordance with Item 1.2 of Annex 3 and item 1.2 of Annex 12 to Commission Delegated Regulation (EU) 2019/980 as it forms part of UK domestic law by virtue of the European Union (Withdrawal) Act 2018, NSAI confirms, to the best of its knowledge, the information contained in therein is in accordance with the facts and makes no omission likely to affect their import;

(c) NSAI confirms that it is unaware of any material change in circumstances to those stated in the report;

(d) C. Ashley Smith, Vice President of NSAI, who supervised the evaluation, is professionally qualified and a member in good standing of the Society of Petroleum Engineers;

(e) NSAI has the relevant and appropriate qualifications, experience, and technical knowledge to professionally and independently appraise the Maverick Natural Resources, LLC interest, which we have reported on;

(f) NSAI considers that the scope of the report is appropriate and was prepared to a standard expected in accordance with FCA Primary Market Technical Note 619.1;

(g) NSAI has at least five years relevant experience in the estimation, assessment, and evaluation of oil, gas, and other liquid hydrocarbons under consideration;

(h) NSAI is an independent petroleum consulting firm founded in 1961 and is independent of Diversified Energy Company PLC (DEC) and its directors, senior management and advisers, has no material interest in DEC or its properties and has acted as an independent competent person for the purposes of providing a report on the assets;

(i) No employee, officer, or director of NSAI is an employee, officer, or director of DEC, nor does NSAI or any of its employees have direct financial interest in DEC. Neither the employment of nor the compensation received by NSAI is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report; and

(j) NSAI is not a sole practitioner.

Part 6
CAPITALISATION AND INDEBTEDNESS

The following tables show the Group's capitalisation and indebtedness as at 31 December 2024. Both the capitalisation and indebtedness information have been extracted without material adjustment from the unaudited management accounts of the Group as at and for the 12-month period ended 31 December 2024.

Capitalisation

The table below sets out the capitalisation of the Group as at 31 December 2024, as extracted from the unaudited management accounts of the Group as at and for the 12-month period ended 31 December 2024:

	Unaudited as at 31 December 2024
	$'000
Shareholders' equity [(1)]	
Share capital	13,796
Share premium	1,262,711
Treasury reserve	(119,006)
Share based payment and other reserves	20,136
Total shareholders' equity	**1,177,637**
Total capitalisation	**2,913,210**

Note:

(1) Shareholders' equity does not include the retained earnings reserve.

Save as set out below, there has been no material change in the Group's capitalisation since 31 December 2024 to the date of this document:

(a) On 20 February 2025, the Company has issued 8,500,000 Ordinary Shares pursuant to the Equity Raise.

Indebtedness

The table below sets out the gross indebtedness of the Group as at 31 December 2024, as extracted from the unaudited management accounts of the Group as at and for the 12-month period ended 31 December 2024:

	Unaudited as at 31 December 2024
	$'000
Current debt	
Guaranteed	–
Secured[(1)]	209,463
Unguaranteed/unsecured	–
Total current debt	**209,463**
Non-current debt	
Guaranteed	–
Secured[(1)]	1,450,010
Unguaranteed/unsecured	76,100
Total non-current debt	**1,526,110**
Total gross indebtedness[(2)]	**1,735,573**

Notes:

(1) Secured debt primarily includes borrowings under the Group's Credit Facility, ABS I Notes to ABS IX Notes, and term loans, which are collaterialised by certain of the Group's producing and midstream assets. Borrowings also contains $6,959,864 in other miscellaneous borrowings primarily related to real estate, vehicles and equipment.

(2) Total gross indebtedness excludes deferred financing costs and $44.6 million in lease liabilities.

The following table sets out the net indebtedness of the Group as at 31 December 2024, as extracted from the unaudited management accounts of the Group as at and for the 12-month period ended 31 December 2024:

	Unaudited as at 31 December 2024
	$'000
Cash and cash equivalents	5,990
Liquidity	**5,990**
Current financial receivable	–
Current portion of non-current debt	(209,463)
Other current financial debt	–
Current financial debt	**(209,463)**
Net current financial (indebtedness)/cash	**(203,487)**
Non-current bank loans	(1,450,010)
Bonds issued	–
Other non-current loans	(76,100)
Non-current financial indebtedness	**(1,526,110)**
Total gross indebtedness [(1)(2)]	**(1,729,597)**

Notes:

(1) Financial instruments related to commodity and interest derivative contracts have been excluded from the table above.

(2) Net financial indebtedness excludes deferred financing costs and $44.6 million in lease liabilities.

There has been no material change in the Group's indebtedness since 31 December 2024 to the date of this document.

Further, the Group does not have any indirect or contingent indebtedness.

Part 7
ADDITIONAL INFORMATION

1. Responsibility

1.1 The Company and its Directors whose names appear in paragraph 7 of this Part 7 ("*Additional Information*"), 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.

2. Incorporation and Registered Office

2.1 The Company was incorporated and registered in England and Wales on 31 July 2014 as a public limited company with the name Diversified Gas & Oil PLC with registered number 09156132 and LEI 213800YR9TFRVHPGOS67. On 6 May 2021, the Company changed its name to Diversified Energy Company PLC.

2.2 The Company is a public company limited by shares and operates under English law. The Company is governed by the provisions of the Articles.

2.3 The registered office of the Company is 4th Floor Phoenix House, 1 Station Hill, Reading, Berkshire, United Kingdom, RG1 1NB and its telephone number is +1-205-408-0909. The Company's website is https://www.div.energy/.

2.4 The principal legislation under which the Company operates and under which the New Shares will be created is the Companies Act 2006. The Ordinary Shares and the New Shares have been duly authorised according to the requirements of the Company's constitution and have all necessary statutory consents. The Ordinary Shares are denominated in Pounds Sterling. The New Shares will be quoted and traded in Pounds Sterling on the London Stock Exchange.

2.5 The Company's auditor for the year ended 31 December 2023 was PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP is registered to carry out audit work by the Institute of Chartered Accountants of England and Wales.

2.6 The accounting reference date of the Company is 31 December.

3. Share Capital

3.1 As at the Latest Practicable Date, the issued share capital of the Company (excluding the Equity Raise Shares) was £10,259,188 divided into 51,295,942 Ordinary Shares of £0.20 each (all of which were fully paid or credited as fully paid). As at the Latest Practicable Date, the Company does not hold any shares in treasury.

3.2 The Ordinary Shares are listed on the equity shares (commercial companies) category of the Official List and admitted to trading on the London Stock Exchange's main market for listed securities. The ISIN of the Ordinary Shares is GB00BQHP5P93.

3.3 The Equity Raise Shares are, and the Over-Allotment Shares if and when issued will be, fully paid, identical to, and rank pari passu with, the Ordinary Shares, including the right to receive all dividends and other distributions declared, made or paid on the Ordinary Shares by reference to a record date on or after Equity Raise Shares Admission and Over-Allotment Shares respectively. The Consideration Shares, when issued and fully paid, will be identical to, and rank pari passu with, the Ordinary Shares, including the right to receive all dividends and other distributions declared, made or paid on the Ordinary Shares by reference to a record date on or after Consideration Shares Admission.

3.4 There are no restrictions on the free transferability of the Ordinary Shares, other than certain transfer restrictions under: (i) the Companies Act 2006 for persons failing to respond to statutory notices issued by the Company requesting for information on interest in a particular holding of shares; (ii) the Articles, under which the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share in certain circumstances; and (iii) the relevant securities laws of the United States and certain other jurisdictions, as may be applicable to the transferor or the transferee.

3.5 Under the Articles, the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share which is not fully paid up but, in the case of a class of shares which has been admitted to the Official List of the FCA, not so as to prevent dealings in those shares from taking place on an open and proper basis or on which the Company has a lien. The Board may also refuse to register any instrument of transfer of a certificated share unless it is left (duly stamped) at the registered office, or such other place as the Board may decide, for registration, accompanied by the certificate for the shares to be transferred and such other evidence (if any) as the Board may reasonably require to prove title of the intending transferor or their right to transfer the shares; and it is in respect of only one class of shares and not in favour of more than four transferees.

3.6 *Existing Shareholder authorities*

(a) By an ordinary resolution at the Company's annual general meeting held on 10 May 2024, the Directors were generally and unconditionally authorised for the purposes of section 551 of the Act, to exercise all the powers of the Company to allot shares and grant rights to subscribe for, or convert any security into, shares:

(i) up to a maximum aggregate nominal amount equal to £6,342,457 (being equal to two-thirds of the nominal value of the Company's current issued share capital), such amount to be reduced by the nominal amount of any relevant securities allotted pursuant the authority in paragraph 12.2, in connection with an offer by way of a pre-emptive offer:

(A) to holders of Ordinary Shares in proportion (as nearly as may be practicable) to their respective holdings; and

(B) to holders of other equity securities as required by the rights of those securities or as the Directors otherwise consider necessary,

but subject to such exclusions or other arrangements as the Directors may deem necessary or expedient in relation to treasury shares, fractional entitlements, record dates, legal or practical problems in or under the laws of any territory or the requirements of any regulatory body or stock exchange; and

(ii) in any other case, up to an aggregate nominal amount of £3,171,228 (being equal to one-third of the nominal value of the Company's current issued share capital), such amount to be reduced by the nominal amount of any equity securities allotted pursuant to the authority in paragraph (i) above in excess of £6,342,457;

provided that such authority shall expire (unless previously revoked by the Company) at the conclusion of the next annual general meeting of the Company after passing of this resolution or 30 June 2025, whichever is earlier, save that in each case the Company may, before such expiry, make an offer or agreement which would or might require equity securities to be granted after the authority has expired and the Directors may allot equity securities in pursuance of any such offer or agreement notwithstanding that this authority has expired.

(b) By a special resolution at the Company's annual general meeting held on 10 May 2024, the Directors were generally and unconditionally empowered to exercise all the powers of the Company to allot equity securities (as defined in section 560 of the Act) for cash pursuant to the authorisation conferred by resolution 13 above and/or to sell Ordinary Shares held by the Company as treasury shares for cash, in each case, as if section 561 of the Act did not apply to the allotment, provided that this power shall be limited to:

(i) the allotment of equity securities or sale of treasury shares in connection with an offer or issue by way of a pre-emptive offer pursuant to an authority granted under resolution (a)(i) above to:

(A) Shareholders in proportion (as nearly as may be practicable) to their existing holdings of Shares; and

(B) holders of other equity securities, if this is required by the rights of those securities or, if the Directors consider it necessary,

but subject to such exclusions or other arrangements as the Directors may consider necessary, expedient or appropriate in relation to treasury shares, fractional entitlements, record dates, legal, regulatory or practical problems in, or under the laws of, any territory (including the requirements of any regulatory body or stock exchange) or any other matter;

(ii) otherwise than pursuant to (b)(i) above, the allotment of further equity securities or sale of treasury shares up to an aggregate nominal amount of £951,368 (representing no more than 10% of the current issued share capital of the Company);

(iii) the allotment of equity securities or sale of treasury shares (otherwise than under paragraph (b)(i) or paragraph (b)(ii) above) up to a nominal amount equal to 20% of any allotment of equity securities or sale of treasury shares from time to time under paragraph (b)(ii) above, such authority to be used only for the purposes of making a follow-on offer which the Board of the Company determines to be of a kind contemplated by paragraph 3 of Section 2B of the Statement of Principles on Disapplying Pre-Emption Rights most recently published by the Pre-Emption Group prior to the date of the notice of the AGM at which these resolutions were passed,

such authority shall expire (unless previously revoked by the Company) at the conclusion of the next annual general meeting of the Company after this resolution is passed or 30 June 2025, whichever is earlier, save that in each case, the Company may, before such expiry, make an offer or agreement which would or might require equity securities to be allotted (or treasury shares to be sold) after the authority expires and the Directors may allot equity securities (or sell treasury shares) in pursuance of any such offer or agreement as if this authority had not expired.

(c) By a special resolution at the Company's annual general meeting held on 10 May 2024, the Directors were generally and unconditionally empowered to exercise all the powers of the Company to allot equity securities (as defined in section 560 of the Act) for cash pursuant to the authorisation conferred by resolution 13 above and/or to sell Ordinary Shares held by the Company as treasury shares for cash, in each case, as if section 561 of the Act did not apply to the allotment, provided that this power shall be limited to:

(i) the allotment of equity securities or sale of treasury shares up to an aggregate nominal amount of £951,368;

(ii) used only for the purpose of financing (or refinancing, if the authority is to be used within 12 months after the original transaction) a transaction which the Directors determine to be an acquisition or a specified capital investment of a kind contemplated by the Statement of Principles on Disapplying Pre-Emption Rights most recently published by the Pre-Emption Group prior to the date of this notice of the AGM at which these resolutions were passed; and

(iii) the allotment of equity securities or sale of treasury shares (otherwise than under paragraph (c)(i) above) up to a nominal amount equal to 20% of any allotment of equity securities or sale of treasury shares from time to time under paragraph c(i) above, such authority to be used only for the purposes of making a follow-on offer which the Board of the Company determines to be of a kind contemplated by paragraph 3 of Section 2B of the Statement of Principles on Disapplying Pre-Emption Rights most recently published by the Pre-Emption Group prior to the date of this notice of the AGM at which these resolutions were passed, such authority shall expire (unless previously revoked by the Company) at the conclusion of the next annual general meeting of the Company after this resolution is passed or 30 June 2025, whichever is earlier, save that in each case, the Company may, before such expiry, make an offer or agreement which would or might require equity securities to be allotted (or treasury shares to be sold) after the authority expires and the Directors may allot equity securities (or sell treasury shares) in pursuance of any such offer or agreement as if this authority had not expired.

(d) The Company has allotted and issued 2,249,650 Ordinary Shares in connection with the Crescent Pass Acquisition, 2,342,445 Ordinary Shares in connection with the East Texas Assets Acquisition and 8,500,000 Ordinary Shares in connection with the Equity Raise in reliance on the existing shareholder authorities set out above. The Company may issue up to a further 850,000 Ordinary Shares in connection with the Over-Allotment Option in reliance on the existing shareholder authorities set out above.

(e) The Company intends to seek shareholder approval for the purposes of section 551 of the Act to allot the Consideration Shares in connection with the Acquisition, and any allotment and issue of the Consideration Shares shall be subject to receipt of such shareholder approval.

4. Incentive Plan

4.1 On 30 January 2017, the Directors implemented an equity incentive plan, which was amended and restated on 27 April 2021 (as amended, the "**Equity Incentive Plan**"), under which the Company offers incentives to employees and the Executive Director. Awards granted under the Equity Incentive Plan shall be administered by the Board (or duly constituted committee thereof), which shall also be responsible for, among other things, construing and interpreting the Equity Incentive Plan. Subject to certain conditions, a total of up to 3,284,031 new Ordinary Shares of the Company from time to time are available to satisfy awards under the Equity Incentive Plan.

4.2 The Equity Incentive Plan provides for the potential award of two types of share option awards: incentive stock options and non-qualified stock options. The Equity Incentive Plan sets out a number of eligibility conditions which must be followed, including that incentive stock options are only to be granted to employees and each award granted under the Equity Incentive Plan must be evidenced by an award agreement. The Equity Incentive Plan also provides for other awards consisting of stock appreciation rights, restricted awards, performance share awards and performance compensation awards. Performance compensation awards may take the form of a cash bonus, a portion of which may be deferred through the grant of restricted stock units. Award levels will be determined each year by the Remuneration Committee. An award may not be granted to an individual if such grant would cause the aggregate total market value (as measured at the respective dates of grant) of the maximum number of shares that may be acquired on realisation of the individual's Equity Incentive Plan awards in relation to the same financial year to exceed 200 per cent. of the individual's base salary at the date of grant (other than the CEO, where it would not exceed 325 per cent. of the CEO's base salary at the date of the grant), subject to the discretion of the Remuneration Committee. The vesting of awards granted to the Executive Director and other senior employees will normally be dependent upon the satisfaction of stretching performance conditions that are appropriate to the strategic objectives of the Company. If the Remuneration Committee so determines upon the grant of certain types of award, the number of shares under an award may be increased to account for dividends paid on any vesting shares in the period between grant and vesting (or such other period as the Remuneration Committee may determine). Alternatively, participants may receive a cash sum equal to the value of dividends paid on any vesting shares in the relevant period. Where appropriate, awards under the Equity Incentive Plan will be granted subject to the Company's policy relating to malus and clawback and post-vesting holding periods. In any 10-year period, the Company may not grant awards under the Equity Incentive Plan if such grant would cause the number of shares that could be issued under the Equity Incentive Plan or any other share plan adopted by the Company or any other company under the Company's control on or after admission to exceed 10 per cent. of the Company's issued ordinary share capital at the proposed date of grant. The Share Option Scheme is governed by the laws of the State of Alabama.

4.3 The Company has also entered into Restricted Stock Unit Agreements with certain employees ("**Recipients**") pursuant to which such employees were granted the following restricted stock units (the "**RSUs**") in the Company to acquire new Ordinary Shares under the Share Option Scheme. As at the Latest Practicable Date, 1,183,973 RSUs are currently outstanding. Each RSU represents the right to one Ordinary Share in the Company. The Recipients do not have any rights as a shareholder with respect to the shares underlying the RSUs, including the rights to vote or to dividends, until the RSUs vest and are settled by the issuance of new Ordinary Shares. In order for the RSUs to vest, the Recipient must remain actively employed with the Company.

4.4 The Company has also entered into Performance Share Award Agreements with Recipients pursuant to which such employees were granted the following performance stock units (the "**PSUs**") in the Company to acquire new Ordinary Shares under the Share Option Scheme. As at the Latest Practicable Date, 1,218,987 PSUs are currently outstanding. Each PSU represents the right to one Ordinary Share in the Company. The Recipients do not have any rights as a shareholder with respect to the shares underlying the PSUs, including the rights to vote or to dividends, until the PSUs vest and are settled by the issuance of new Ordinary Shares or the transfer of Ordinary Shares from the EBT. The PSUs are expected to vest no later than 15 March 2025, 31 March 2026 and 31 March 2027, subject to certain performance targets being met over the three-year performance periods of 1 January 2022 through 31 December 2024, 1 January 2023 through 31 December 2025 and 1 January 2024 through 31 December 2026, respectively. The performance targets measure three-year average free cash flow growth, three-year average return on equity, three-year absolute TSR, three-year TSR relative to FTSE 250 Index TSR and three-year methane intensity reduction.

4.5 As of the date of this document, under the Share Option Scheme, the Company has no unvested options outstanding to directors and employees of the Group, and 153,631 vested options which have not been exercised. The Company has granted options under the Share Option Scheme over 144,006 new Ordinary Shares outstanding (all of which been vested but remain unexercised) in aggregate at an exercise price of 1,680 pence per share to a total of 10 employees (including the Executive Director), over 9,625 new Ordinary Shares outstanding (all of which have been vested but remain unexercised) in aggregate at an exercise price of 2,400 pence per share to two employees.

4.6 The following options and awards have been granted to the Directors and Senior Managers and remain outstanding as at the Latest Practicable Date.

Name	Ordinary Shares subject to the option/award[3]	Exercise period	Exercise price per share (£)
Directors			
Robert Russell "Rusty" Hutson, Jr.	70,101[1]	In one tranche no later than 15 March 2025	
	98,045[1]	In one tranche no later than 31 March 2026	
	227,151[1]	In one tranche no later than 31 March 2027	
	64,333	Expire on 4/14/2028	£16.80
	6,600	Expire on 5/9/2029	£24.00
Senior Managers			
Bradley Grafton Gray	17,958[2]	In one tranche no later than 15 March 2025	
	17,958[1]	In one tranche no later than 15 March 2025	
	24,783[2]	In one tranche no later than 31 March 2026	
	24,783[1]	In one tranche no later than 31 March 2026	
	86,246[2]	In one tranche no later than 31 March 2027	
	36,962[1]	In one tranche no later than 31 March 2027	
	29,485	Expire on 4/14/2028	£16.80
	3,025	Expire on 5/9/2029	£24.00
Benjamin Sullivan..............................	15,357[2]	In one tranche no later than 15 March 2025	
	15,357[1]	In one tranche no later than 15 March 2025	
	20,834[2]	In one tranche no later than 31 March 2026	
	20,834[1]	In one tranche no later than 31 March 2026	
	70,565[2]	In one tranche no later than 31 March 2027	
	30,242[1]	In one tranche no later than 31 March 2027	

Notes:

(1) Performance share awards issued by the Company

(2) Restricted stock units issued by the Company

(3) Awards are exclusive of any accrued dividend equivalents

4.7 Other than pursuant to the Transactions and pursuant to the vesting of awards and the exercise of options granted and to be granted under the share option plans, there is no present intention to issue any Ordinary Shares in the capital of the Company or transfer any Ordinary Shares from the EBT, and the Company has no other convertible securities, exchangeable securities or securities with warrants in issue.

5. Articles of Association

5.1 The Articles were adopted pursuant to a special resolution passed on 30 January 2018 and last amended by special resolution passed on 4 December 2023 and are available for inspection as set out in paragraph 23 of this Part 7 ("*Additional Information*").

6. Depositary Interests and Settlement

6.1 Following the NYSE listing, Ordinary Shares are not capable of being transferred or settled directly through the CREST settlement system. Therefore, the Company has entered into arrangements to enable certain Shareholders to hold, and settle transfers of, their interests in Ordinary Shares in CREST in the form of Depositary Interests ("**DIs**"), each representing an entitlement to one underlying Ordinary Share.

6.2 To allow Shareholders to continue to hold, and settle transfers of, their interests in Ordinary Shares through CREST, the DI Depositary may, from time to time and at the request of the Shareholder, issue DIs representing such Ordinary Shares on a one-to-one basis through CREST to the CREST accounts in which the relevant Shareholder holds Ordinary Shares. DIs are created and issued under the terms of the deed poll made by the DI Depositary constituting the DIs (the "**DI Deed**"), which govern the relationship between the DI Depositary and the holders of DIs from time to time. The DI Deed is available on request from the DI Depositary.

6.3 The registered holder of Ordinary Shares represented by DIs is Cede & Co., as nominee of DTC. The custodian of those Ordinary Shares is the DI Custodian who holds the book entry interest in such shares through the DTC clearing system for the DI Depositary. The DI Depositary holds the book entry interests in those Ordinary Shares on trust (as bare trustee under English law) for the holders of DIs as tenants in common. The DI Depositary maintains a register of holders of DIs and a copy of such register is also made available to the Company.

6.4 Under the DI Deed, the DI Depositary: (a) sends out notices of general meetings to the holders of DIs; and (b) produces a definitive list of holders of DIs at the record date for such general meetings. In addition, holders of DIs are entitled to provide voting instructions via the DI Depositary to the DI Custodian (being the custodian of Ordinary Shares underlying DIs) in respect of the underlying Ordinary Shares.

6.5 As a result, the holders of DIs are able to:

- receive notices of general meetings of the Company;
- give directions as to voting at general meetings of the Company;
- request to be appointed as proxy in respect of Ordinary Shares underlying their DIs, enabling them to attend and speak at general meetings of the Company; and
- have made available to them, at their request, copies of the annual report and accounts of the Company and all other documents issued by the Company to Shareholders generally.

6.6 Holders of DIs are, to the extent possible, otherwise treated in the same manner as if they were registered holders of Ordinary Shares underlying their DIs, to the extent possible in accordance with applicable law, DTC operations, the CREST arrangements and the DI Deed. This includes being able to receive dividends and participate in capital events, so far as practicable, in the same manner as registered holders of Ordinary Shares.

6.7 Holders of DIs can (with settlement occurring through DIs) trade Ordinary Shares on the London Stock Exchange or choose to cancel their DIs so as to receive their Ordinary Shares in a nominated DTC participant account and trade the underlying Ordinary Shares on the NYSE.

6.8 Holders of DIs may cancel their DIs by submitting a cross-border instruction in respect of the underlying Ordinary Shares through CREST to the DI Depositary in the form of a CREST stock withdrawal message. This message must include the account information of the nominated DTC participant in accordance with the rules and practices of the DI Depositary, CREST and DTC. When submitting such cross-border instruction, holders of DIs will be required to warrant that such transfer will not represent a change in beneficial ownership. Valid instructions received by the DI Depositary are typically completed within 48 hours (excluding any non-working days in any relevant jurisdictions) and holders of DIs should consider these timings, and those of their chosen broker, when instructing corresponding trades on the New York Stock Exchange. Cancellation of DIs is subject to a charge. For details of the current cancellation charges or for assistance in cancelling DIs and lodging cross-border instructions, holders of DIs should contact the DI Depositary by email uk.globaltransactions@computershare.com.

7. Directors and Senior Managers

7.1 Directors

The current Directors and their functions are as follows:

Name	Position	Date appointed to the Board
David Edward Johnson	Non-Executive Chair	3 February 2017
Robert Russell “Rusty” Hutson, Jr.	Chief Executive Officer	31 July 2014
Martin Keith Thomas	Non-executive Vice Chairman	1 January 2015
David Jackson Turner, Jr.	Non-Executive Director	27 May 2019
Sandra (Sandy) Mary Stash	Non-Executive Director	21 October 2019
Kathryn Z. Klaber	Non-Executive Director	1 January 2023

The business address of each of the Directors (in such capacity) is 4th Floor Phoenix House, 1 Station Hill, Reading, Berkshire, United Kingdom, RG1 1NB.

7.2 Profiles of the Directors

The business experience and principal business activities outside of the Group of each of the Directors are as follows:

David Edward Johnson

Mr. Johnson has served on the Company’s board of directors since February 2017 and as the Company’s Independent Chairman since April 2019. He has worked at a number of leading investment firms, as both an investment analyst and a manager, and more recently in equity sales and investment management. Mr. Johnson currently serves on the board of Chelverton Equity Partners, an AIM-listed holding company, where he serves as a member of the Remuneration, Audit and Nomination committees. Previously, Mr. Johnson was a consultant at Chelverton Asset Management from August 2016 to February 2019. Prior to that, he worked as a fund manager for the investment department a large insurance company and then as Head of Sales and Head of Equities at a London investment bank. Mr. Johnson earned a Bachelor of Arts in Economics from the University of Reading.

Robert Russell "Rusty" Hutson, Jr.

Mr. Hutson is the Group's co-founder and has served as its Chief Executive Officer since the founding of the Company's predecessor entity in 2001. Mr. Hutson also serves on the Board of Directors. Prior to founding the Company, Mr. Hutson held finance and accounting roles for 13 years at Bank One (Columbus, Ohio) and Compass Bank (Birmingham, Alabama). Mr. Hutson has a B.S. degree in Accounting from Fairmont State College—West Virginia and received a CPA license (Ohio).

Martin Keith Thomas

Mr. Thomas has served on the Company's Board of Directors since January 2015. Since January 2022, Mr. Thomas has served as a consultant at the law firm Wedlake Bell LLP, from where he was previously a Partner from January 2018 to December 2021. During his more than 30-year legal career, Mr. Thomas has also served as Partner of Watson Farley & Williams LLP from February 2015 to April 2017 and as consultant of the same firm from May 2017 to May 2018. Mr. Thomas earned a Bachelor of Laws from the University of Reading and completed his Law Society Final Examinations at The College of Law in the UK.

David Jackson Turner, Jr.

Mr. Turner has served on the Company's Board of Directors since May 2019. Mr. Turner has served as Chief Financial Officer of Regions Financial Corporation (NYSE: RF) since 2010 where he leads all finance operations, including mergers and acquisitions, financial systems, investor relations, corporate treasury, corporate tax, management planning and reporting and accounting. Prior to his appointment as Chief Financial Officer, Mr. Turner oversaw the Internal Audit Division for AmSouth Bank (which merged with Regions Financial Corporation in 2006) from April 2005 to March 2010. Before beginning his banking career, Mr. Turner was a certified public accountant and an Audit Partner with Arthur Andersen and KPMG specialising in financial services clients. He earned a Bachelor of Science in Accounting from the University of Alabama.

Sandra (Sandy) Mary Stash

Ms. Stash has served on the Company's Board of Directors since October 2019. Ms. Stash joined Tullow Oil in October 2013 serving as Executive Vice President of Safety, Operations and Engineering, and External Affairs where she served until March 2020. Ms. Stash is a Certified Director of the US National Association of Corporate Directors and a Fellow of the Canadian Academy of Engineering and currently serves on the boards of Chaarat Gold Holdings Limited (AIM: CGH), Medallion Midstream LLC, Trans Mountain Company, Warriors and Quiet Waters as Chair, the Colorado School of Mines Board of Governors, First Montana Bank, and the African Gifted Foundation. Ms. Stash earned a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines and is a Registered Professional Engineer.

Kathryn Z. Klaber

Ms. Klaber has served on the Company's Board of Directors since January 2023. Since 2014, Ms. Klaber has served as the Managing Director of The Klaber Group, which provides strategic consulting services to businesses and organisations with a focus on energy development in the United States and abroad. Prior to founding The Klaber Group, Ms. Klaber launched the Marcellus Shale Coalition, serving as its first CEO from 2009 to 2013. Previously in her career, Ms. Klaber also served as the Executive Vice President for Competitiveness at the Allegheny Conference on Community Development, Executive Director of the Pennsylvania Economy League, and consultant at Environmental Resources Management, where she gained significant experience in EHS strategy and compliance. Ms. Klaber received her B.A. in Environmental Science from Bucknell University and her MBA from Carnegie Mellon University.

A list of the companies and partnerships of which the Directors are or have been a director or partner within the past five years is set out in paragraph 9 of this Part 7 ("*Additional Information*").

7.3 Senior Managers

The Senior Managers of the Group are:

Name	Position
Bradley Grafton Gray	President and Chief Financial Officer
Benjamin M. Sullivan	Senior Executive Vice President, Chief Legal & Risk Officer

7.4 Profiles of the Senior Managers

The business experience and principal business activities of each of the Senior Managers are as follows:

Bradley Grafton Gray

Mr. Gray has served as the Group's President and Chief Financial Officer since September 2023. Mr. Gray has also served as the Group's Executive Vice President, Chief Operating Officer since October 2016 to September 2023. Mr. Gray has also served on the Board of Directors until September 2023. Prior to joining the Group, Mr. Gray served as the Senior Vice President and Chief Financial Officer for Royal Cup, Inc. from August 2014 to October 2016. Prior to that, from 2006 to 2014, Mr. Gray served in various roles at The McPherson Companies, Inc., most recently as Executive Vice President and Chief Financial Officer from September 2006 to December 2013. Mr. Gray previously worked in various financial and operational roles at Saks Incorporated from 1997 to 2006. Mr. Gray has a B.S. degree in Accounting from the University of Alabama and was formerly a licensed CPA (Alabama).

Benjamin M. Sullivan

Mr. Sullivan has served as the Group's Senior Executive Vice President, Chief Legal & Risk Officer since September 2023. Prior to that, Mr. Sullivan served as the Group's Executive Vice President, General Counsel from 2019 to September 2023. Prior to joining us, Mr. Sullivan worked with Greylock Energy, LLC (an ArcLight Capital Partners portfolio company) and its predecessor, Energy Corporation of America, from 2012 to 2017, most recently as Executive Vice President, General Counsel and Corporate Secretary from 2017 to 2019. Prior to that, Mr. Sullivan served as counsel for EQT Corporation from 2006 to 2012. He is a member of the leadership and board of directors of several commerce, legal and industry groups, and has considerable experience in corporate governance and reporting/ sustainability, complex commercial transactions, land/real estate, acquisitions & divestitures, financing, government investigations and corporate workouts and restructurings. Mr. Sullivan received a B.A. from University of Kentucky and a J.D. degree from the West Virginia University College of Law. He holds licenses to practice law in Pennsylvania and West Virginia.

8. Directors' and Senior Managers' Interests

8.1 Directors' and Senior Managers' interests in share capital

The following table sets out the interests in the share capital of the Company of the Directors and Senior Managers (including beneficial interests or interests of a person closely associated with a Director or a Senior Manager within the meaning of the UK Market Abuse Regulation) as at the Latest Practicable Date:

Director	Ordinary Shares immediately held at the Latest Practicable Date[(1)]	Percentage of issued Ordinary Share capital at the Latest Practicable Date[(1)]
Chair and Executive Director		
David Edward Johnson	23,750	0.05%
Robert Rusty Russell Hutson, Jr.	1,234,134	2.41%

Director	Ordinary Shares immediately held at the Latest Practicable Date[1]	Percentage of issued Ordinary Share capital at the Latest Practicable Date[1]
Non-Executive Directors		
Martin Keith Thomas	113,850	0.22%
David Jackson Turner, Jr.	33,087	0.06%
Kathryn Z. Klaber	2,912	0.01%
Sandra (Sandy) Mary Stash	4,092	0.01%
Senior Managers		
Bradley Grafton Gray	165,585	0.32%
Benjamin M. Sullivan	40,417	0.08%

Note:

(1) Details of the options and awards over Ordinary Shares under the Equity Incentive Plan held by the Directors and Senior Managers are set out in paragraph 4 above and details of the relevant share option plans are set out in paragraph 4 of this Part 7 ("*Additional Information*"). The options and awards are not included in the interests of the Directors and Senior Managers shown in the table above.

8.2 Other interests

Save as disclosed in paragraphs 4 and 8 of this Part 7 ("*Additional Information*") above, no Director or Senior Manager has any interest in the share capital or loan capital of the Company or any of its subsidiaries nor does any person closely associated (within the meaning of section 252 of the Companies Act 2006) with the Directors or Senior Managers have any such interests, whether beneficial or non-beneficial.

No other person has any interest, including a conflict of interest, that is material to Admission.

9. Other Directorships

In addition to their directorships of the Company (in the case of the Directors), the Directors and the Senior Managers hold or have held the following directorships (other than directorships of subsidiaries of the Company), and are or were members of the following partnerships, within the past five years:

Name	Current or former directorship/ partnership	Position still held (Y/N)
Chair		
David Edward Johnson	Bilby plc., Non-executive Director	N
	Fit Together (UK) Limited, Director	N
	Tribeca Nominee Limited, Director	N
	Chelverton Equity Partners plc, Non-executive Director	Y
Executive Director		
Robert Russell "Rusty" Hutson, Jr.	None	None
Non-Executive Directors		
Martin Keith Thomas	Wedlake Bell LLP, Consultant	Y
	Jasper Consultants Limited, Director	Y
	Pristec AG, Member of the Supervisory Board	N
	Blue Ocean Consolidated Holding Limited, Director	N
	Chadbourne & Parke (London) LLP, Partner	N
	Energy Everything Investments PLC, Director	N
	Hunton & Williams LLP, Partner	N
	Pemar Capital Partners PLC, Director	N
	Watson Farley & Williams LLP, Partner	N

Name	Current or former directorship/ partnership	Position still held (Y/N)
David Jackson Turner, Jr	Regions Financial Corporation, Chief Financial Officer	Y
	Junior Achievement of Alabama	Y
Sandra (Sandy) Mary Stash	Board of Governors at Colorado School of Mines	Y
	Institute for Sustainable Communities	N
	International Women's Forum	N
	The Pointe at Georgetown LLC	N
	EDF Energy Thermal Generation Limited	N
	Montana Tech Foundation	N
	Trans Mountain Pipeline Company	Y
	First Montana Bank	Y
	Lucid Energy	N
	Chaarat Gold Holdings Limited	Y
	EVRAZ plc	N
	Medallion Midstream, LLC	Y
Kathryn Z. Klaber	The Klaber Group	Y
Senior Managers		
Bradley Grafton Gray	Royal Cup, Inc., Senior Vice President and Chief Financial Officer	N
	The McPherson Companies, Inc., Executive Vice President and Chief Financial Officer	N
Benjamin Sullivan	Gas & Oil Association of West Virginia	Y
	West Virginia Chamber of Commerce	Y
	Energy & Mineral Law Foundation	Y
	Marcellus Shale Coalition	Y
	Hatfield & McCoy Regional Recreation Authority	N

10. Directors' and Senior Managers' Confirmations

10.1 As at the date of this document, none of the Directors or Senior Managers have, during the five years prior to the date of this document:

(a) been convicted in relation to a fraudulent offence;

(b) been associated with any bankruptcies, receiverships, liquidations or companies put into administration while acting in the capacity of a member of the administrative, management or supervisory bodies or as a partner, founder or senior manager of any partnership or company;

(c) been subject to any official public incrimination and/or sanctions by any statutory or regulatory authorities (including any designated professional bodies); or

(d) been disqualified by a court from acting as a director of a company or from acting as a member of the administrative, management or supervisory bodies of any company or from acting in the management or conduct of the affairs of any company.

There are no potential conflicts of interest between each of the Directors' duties to the Company and their respective private interests and any other duties. There is no interest, including any conflicting interest that is material to the Company.

None of the Directors or Senior Managers were selected to act in such capacity pursuant to any arrangement or understanding with any major shareholder, customer, supplier or other person having a business connection with the Group.

As at the date of this document, no restrictions have been agreed by any Director or Senior Manager on the disposal within a certain time period of their holdings of their Ordinary Shares.

There are no family relationships between any of the Directors, between any of the Senior Managers or between any of the Directors and the Senior Managers.

11. Major Shareholders

11.1 So far as the Company is aware, as at the Latest Practicable Date, the following persons (other than the Directors and Senior Managers) had notifiable interests in three per cent. or more of the issued share capital of the Company:

Shareholder	Ordinary Shares held at the Latest Practicable Date	Percentage of Ordinary Share capital at the Latest Practicable Date(%)
BlackRock	4,936,644	9.62
Columbia Management Investment Advisers	3,654,367	7.12
Jupiter Asset Management	2,792,978	5.44
Maverick Natural Resources	2,342,445	4.57
Hargreaves Lansdown, stockbrokers (EO)	2,126,842	4.15
Interactive Investor (EO)	2,077,014	4.05
M&G Investments	1,754,311	3.42
Vanguard Group	1,593,364	3.11

11.2 Following Consideration Shares Admission (assuming the Over-Allotment Option is exercised in full and the maximum number of Consideration Shares are issued), EIG and FSEP are expected to have notifiable interests in 17.54 per cent. and 4.52 per cent. respectively of the Enlarged Issued Share Capital. Save as set out in this paragraph, the Company is not aware of any person who has or will immediately following the Equity Raise Shares Admission, the Over-Allotment Shares Admission and/or the Consideration Shares Admission have a notifiable interest in three per cent. or more of the issued share capital of the Company.

11.3 The Company is not aware of any person who either as at the date of this document or immediately following the Equity Raise Shares Admission, the Over-Allotment Shares Admission and/or the Consideration Shares Admission, exercises, or could exercise, directly or indirectly, jointly or severally, control over the Company nor is it aware of any arrangements, the operation of which may at a subsequent date result in a change in control of the Company.

11.4 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.

11.5 There are no arrangements, known to the Company, the operation of which may at a subsequent date result in a change of control of the Company.

12. Related Party Transactions

The Group

Other than as publicly disclosed by the Company, there are no related party transactions within the meaning of UK-adopted international accounting standards as defined in s 474(1) CA 2006 between the Group and its related parties that were entered into during the financial year ended 31 December 2023, during the six-month period ended 30 June 2024 or during the period from and including 1 July 2024 up to and including the Latest Practicable Date.

The Maverick Group

There are no related party transactions within the meaning of UK-adopted international accounting standards as defined in s 474(1) CA 2006 between the Maverick Group and its related parties that were entered into during the financial year ended 31 December 2023 or during the period from and including 1 January 2024 up to and including the Latest Practicable Date.

13. Subsidiaries, Investments and Principal Establishments

13.1 The Company is the holding company of the Group. The significant subsidiaries and subsidiary undertakings of the Company are as follows:

Name	Country of incorporation/ Principal place of business	Principal activity	Effective interest and proportion of equity held
Diversified Gas & Oil Corporation	United States	Oil and natural gas operations	100
Diversified Production LLC	United States	Oil and natural gas operations	100
Diversified Midstream LLC	United States	Oil and natural gas non-operated assets	100
Diversified Energy Marketing, LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS Holdings LLC	United States	Holding company	100
Diversified ABS LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS Phase II Holdings LLC	United States	Holding company	100
Diversified ABS Phase II LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS Phase III Upstream LLC	United States	Holding company	100
Diversified ABS Phase IV Holdings LLC	United States	Holding company	100
Diversified ABS Phase IV LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS Phase V Upstream LLC	United States	Holding company	100
Sooner State Joint ABS Holdings LLC	United States	Holding company	100
Diversified ABS Phase VI Holdings LLC	United States	Holding company	100
Diversified ABS Phase VI LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS VI Upstream LLC	United States	Oil and natural gas non-operated assets	100
Oaktree ABS VI Upstream LLC	United States	Oil and natural gas non-operated assets	100
DP Lion Equity Holdco LLC	United States	Holding company	20
DP Lion HoldCo LLC	United States	Holding company	100
DP RBL Co LLC	United States	Holding company	100
DP Legacy Central LLC	United States	Oil and natural gas non-operated assets	100
DP Bluegrass Holdings LLC	United States	Holding company	100
DP Bluegrass LLC	United States	Oil and natural gas non-operated assets	100
BlueStone Natural Resources II, LLC	United States	Oil and natural gas non-operated assets	100
Cranberry Pipeline Corporation	United States	Oil and natural gas non-operated assets	100
Coalfield Pipeline Company	United States	Oil and natural gas non-operated assets	100
DM Bluebonnet LLC	United States	Oil and natural gas non-operated assets	100
DP Tapstone Energy Holdings, LLC	United States	Holding company	100
DP Legacy Tapstone LLC	United States	Oil and natural gas non-operated assets	100
Chesapeake Granite Wash Trust	United States	Oil and natural gas non-operated assets	100
Black Bear Midstream Holdings LLC	United States	Oil and natural gas non-operated assets	100
Black Bear Midstream LLC	United States	Oil and natural gas non-operated assets	100
Black Bear Liquids LLC	United States	Oil and natural gas non-operated assets	100
Black Bear Liquids Marketing LLC	United States	Oil and natural gas non-operated assets	100
DM Pennsylvania Holdco LLC	United States	Holding company	100
Diversified Energy Group LLC	United States	Oil and natural gas non-operated assets	100
Diversified Energy Company LLC	United States	Oil and natural gas non-operated assets	100
Next LVL Energy, LLC	United States	Oil and natural gas non-operated assets	100
Splendid Land, LLC	United States	Oil and natural gas non-operated assets	55
Riverside Land, LLC	United States	Oil and natural gas non-operated assets	55
Old Faithful Land, LLC	United States	Oil and natural gas non-operated assets	55
Link Land, LLC	United States	Oil and natural gas non-operated assets	55
Giant Land, LLC	United States	Oil and natural gas non-operated assets	55
DP Mustang Holdco LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS VIII LLC	United States	Oil and natural gas non-operated assets	100

Name	Country of incorporation/ Principal place of business	Principal activity	Effective interest and proportion of equity held
Diversified ABS VIII Holdings LLC	United States	Holding company	100
OCM Denali Holdings, LLC	United States	Oil and natural gas non-operated assets	100
DP Yellowjacket Equity HoldCo LLC	United States	Oil and natural gas non-operated assets	100
DP Yellowjacket HoldCo LLC	United States	Holding company	100
DM Yellowjacket HoldCo LLC	United States	Holding company	100
Tanos TX HoldCo LLC	United States	Holding company	100
Diversified ABS IX Holdings LLC	United States	Holding company	100

13.2 Save as described above, there are no undertakings in which the Company holds a proportion of the share capital which are likely to have a significant effect on the assessment of the Group's assets and liabilities, financial position or profits and losses.

14. Certain UK Tax Considerations

The following statements are intended only as a general guide to certain UK tax considerations and do not purport to be a complete analysis of all potential UK tax consequences of subscribing for, holding or disposing of Ordinary Shares (including DIs). Prospective investors in Ordinary Shares (including DIs) are advised to consult their own professional advisers concerning the tax consequences of the acquisition, ownership and disposition of such shares or rights. The following statements are based on current UK tax legislation as applied in England and Wales and the current published practice of HMRC (which may not be binding on HMRC) in each case as of the Latest Practicable Date before the date of this document, both of which are subject to change at any time, possibly with retroactive effect. They apply only to Shareholders who are resident, and in the case of individuals domiciled or deemed domiciled, for tax purposes in (and only in) the United Kingdom and to whom "split year" treatment does not apply (except insofar as express reference is made to the treatment of non-UK residents), who hold their Ordinary Shares (including DIs) as an investment (other than in an individual savings account or a self-invested personal pension) and who are, or are treated as, the absolute beneficial owners of both their Ordinary Shares (including DIs) and any dividends paid on them. The tax position of certain categories of Shareholders who are subject to special rules (such as a person subscribing for Ordinary Shares (including DIs) in connection with employment, dealers in securities, insurance companies and collective investment schemes) is not considered. The statements do not apply to any Shareholder who either directly or indirectly holds or controls 10% or more of the Company's share capital (or class thereof), voting power or profits.

The tax legislation of the United Kingdom and the tax legislation of the jurisdictions or prospective investors may have an impact on the income received from the Ordinary Shares (including DIs). The statements summarise the current position and are intended as a general guide only. Prospective investors who are in any doubt about their tax position or who may be subject to tax in a jurisdiction other than the United Kingdom are strongly recommended to consult their own professional advisers.

14.1 Taxation of capital gains

(a) UK resident Shareholders

A disposal or deemed disposal of Ordinary Shares (including DIs) by an individual or corporate Shareholder who is tax resident in the United Kingdom may, depending on the Shareholder's circumstances and subject to any available exemptions or reliefs, give rise to a chargeable gain or allowable loss for the purposes of UK taxation of chargeable gains.

Any chargeable gain (or allowable loss) will generally be calculated by reference to the consideration received for the disposal of the Ordinary Shares (including DIs) less the allowable cost to the Shareholder of acquiring such Ordinary Shares (including DIs).

The applicable tax rates for individual Shareholders realising a gain on the disposal of Ordinary Shares (including DIs) is, broadly, 18% for basic rate taxpayers and 24% for higher and additional rate taxpayers. For corporate Shareholders, Corporation tax is generally charged on chargeable gains at the rate applicable to the relevant corporate Shareholder (the main rate of UK corporation tax is currently 25% for financial year 2024/2025).

(b) Non-UK Shareholders

Shareholders who are not resident in the United Kingdom and, in the case of an individual Shareholder, not temporarily non-resident, should not be liable for UK tax on capital gains realised on a sale or other disposal of Ordinary Shares (including DIs) unless (i) such Ordinary Shares (including DIs) are used, held or acquired for the purposes of a trade, profession or vocation carried on in the United Kingdom through a branch or agency or, in the case of a corporate Shareholder, through a permanent establishment or (ii) where certain conditions are met, the Company derives 75% or more of its gross value from UK land. Shareholders who are not resident in the United Kingdom may be subject to non-UK taxation on any gain under local law.

Generally, an individual Shareholder who has ceased to be resident in the United Kingdom for UK tax purposes for a period of five years or less and who disposes of Ordinary Shares (including DIs) during that period may be liable on their return to the United Kingdom to UK taxation on any capital gain realised (subject to any available exemption or relief).

14.2 **Taxation of Dividends**

A UK resident Shareholder's liability to tax on dividends received will depend on the individual circumstances of that Shareholder:

(a) UK resident individual Shareholders

All dividends received by a UK tax resident individual Shareholder of any Ordinary Shares (including DIs) from the Company or from other sources will form part of the Shareholder's total income for income tax purposes and will constitute the top slice of that income. A nil rate of income tax will apply to the first £500 (for tax year 2024/2025) of taxable dividend income received by the Shareholder in a tax year (the "**dividend allowance**"). Income within the dividend allowance will be taken into account in determining whether income in excess of the dividend allowance falls within the basic rate, higher rate or additional rate tax bands. Dividend income in excess of the dividend allowance will be taxed at 8.75% to the extent that the excess amount falls within the basic rate tax band, 33.75% to the extent that the excess amount falls within the higher rate tax band and 39.35% to the extent that the excess amount falls within the additional rate tax band.

(b) UK resident corporate Shareholders

It is likely that most dividends paid on the Ordinary Shares (including DIs) to UK resident corporate Shareholders would not be subject to UK corporation tax so long as the dividends qualify for exemption (as is likely). However, it should be noted that the exemptions are not comprehensive, their applicability will depend on a Shareholder's own circumstances and they are also subject to anti-avoidance rules. Shareholders within the charge to corporation tax should consult their own professional advisers.

(c) Non-UK resident 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.

Each Shareholder should obtain professional advice on its own position as it will depend on its own individual circumstances.

(d) Withholding tax

The Company will not be required to withhold UK tax at source when paying dividends.

14.3 **UK Stamp Duty and Stamp Duty Reserve Tax ("SDRT")**

The following statements are intended as a general guide to the current UK stamp duty and SDRT position and apply regardless of whether or not a Shareholder is resident in the UK for UK tax purposes. Certain categories of person, including intermediaries, brokers, dealers and persons connected with depositary receipt arrangements and clearance services, may not be liable to stamp duty or SDRT or may be liable at a higher rate or may, although not primarily liable for the tax, be required to notify and account for it under the Stamp Duty Reserve Tax Regulations 1986. The following statements apply only to Ordinary Shares that are registered on the main share register in the United Kingdom. For the avoidance of doubt, the position in relation to Ordinary Shares that are registered on any overseas branch share register or held through a depositary system or clearance service is not considered other than to the extent expressly set out below. Prospective investors who are in any doubt about their tax position are strongly recommended to consult their own professional advisers.

(a) General

There is generally no liability to stamp duty or SDRT on an issue of new Ordinary Shares in registered form by the Company.

(b) Transfers of DIs in CREST

Transfers of DIs in CREST should not be subject to SDRT, on the basis that the underlying share register does not change, or stamp duty, on the basis that no instrument of transfer is required.

(c) Ordinary Shares held through Clearance Systems or Depositary Receipt Systems

Transfers of Ordinary Shares to, or to a nominee or agent for, a person whose business is or includes issuing depositary receipts or to, or to a nominee or agent for, a person whose business is or includes the provision of clearance services, will generally be subject to stamp duty or SDRT at 1.5% of the amount or value of the consideration or, in certain circumstances, the value of the Ordinary Shares transferred unless, in the context of a clearance service, the clearance service has made and maintained an election under section 97A of the UK Finance Act 1986. In practice, any liability for stamp duty or SDRT is in general borne by such person depositing the relevant shares in the depositary receipt system or clearance service. UK stamp duty and SDRT will not, however, arise on a transfer of Ordinary Shares to a depositary receipt issuer or to a clearance service to the extent that such transfer is an "exempt capital-raising transfer" or an "exempt listing transfer," as defined in Finance Act 2024.

15. Material Contracts

The Group

15.1 The following is a summary of those material contracts, not being contracts entered into in the ordinary course of business, which have been entered into by the Company or any member of the Group within the two years immediately preceding the date of this document and of those other contracts, not being contracts entered into in the ordinary course of business by any member of the Group, that contain provisions under which the Company and/or any member of the Group has an obligation or entitlement which is or may be material to the Group as at the date of this document:

(a) For details of the Agreement, the Registration Rights Agreement and Relationship Agreement, please see section 5 (*Key terms of the Acquisition*) of Part 1 (*Information on the Group*).

(b) 2025 Prospectus Sponsor Agreement

On 20 February 2025, the Company and Stifel entered into a sponsor agreement pursuant to which Stifel agreed to act as the Company's sponsor under the Listing Rules in connection with the New Shares Admission and publication of this document as required under the Listing Rules (the "**Prospectus Sponsor Agreement**"). The Sponsor Agreement provided for the payment of certain fees and expenses by the Company to Stifel as sponsor.

Under the terms of the Sponsor Agreement, the Company agreed to provide certain customary warranties, representations and undertakings in favour of Stifel as sponsor in relation to, amongst other things, the accuracy of information in this document and other matters relating to the Group and the acquisition. The Company has also agreed to indemnify the Stifel as sponsor and its affiliates against, among other things, claims made against them or losses incurred by them in connection with the acquisition, subject to certain exceptions.

The Sponsor Agreement is governed by English law.

(c) Underwriting Agreement

On 19 February 2025, the Company entered into an underwriting agreement (the "**Underwriting Agreement**") with Citigroup Global Markets Inc. and Mizuho Securities USA LLC, acting as the representative for the underwriters in the Capital Raise (the "**Underwriters**"). Subject to the terms and conditions stated in the Underwriting Agreement, each Underwriter severally agreed to purchase, and the Company agreed to sell to that Underwriter, 8,500,000 Ordinary Shares (and up to an additional 850,000 ordinary shares pursuant to an over-allotment option). The Underwriting Agreement provided that the obligations of the Underwriters to subscribe for the Ordinary Shares were subject to approval of legal matters by counsel and to other conditions.

The Company has also granted to the Underwriters an option, exercisable for 30 days from the date of the Underwriting Agreement to subscribe for up to 850,000 new Ordinary Shares, at $14.50 per Ordinary Share, being the price at which the Equity Raise Shares were issued and allotted in the Equity Raise. To the extent the option is exercised, each Underwriter is required to subscribe for a number of additional Ordinary Shares approximately proportionate to that Underwriter's initial purchase commitment.

The Underwriting Agreement is governed by New York law.

(d) East Texas Assets purchase and sale agreement

On 19 August 2024, the Company executed a conditional purchase and sale agreement (the "**East Texas Assets PSA**") in connection with the acquisition of operated natural gas properties located within eastern Texas (the "**East Texas Assets**") from Maverick, which was completed on 30 October 2024. The total gross purchase for this acquisition payable by the Group was $69 million before customary purchase price adjustments and the net consideration for the East Texas Assets consisted of a combination of the allotment and issue of 2,342,445 Ordinary Shares and cash consideration of $41 million.

The East Texas Assets PSA is governed by the laws of the state of Texas, United States.

(e) Crescent Pass purchase and sale agreement

On 9 July 2024, the Company executed a conditional purchase and sale agreement (the "**Crescent Pass PSA**") in connection with the acquisition of high-working interest, operated natural gas properties and related facilities located within eastern Texas (the "**Crescent Pass Assets**") from Crescent Pass Energy ("**Crescent Pass**"), which was completed on 15 August 2024. The gross consideration for this acquisition amounted to $101 million and after customary purchase price adjustments. The net consideration for the acquisition of the Crescent Pass Assets comprised the issue of 2,249,650 new Ordinary Shares to Crescent Pass (subject to a customary commercial lock-up agreement), and cash consideration of $71 million.

The Crescent Pass PSA is governed by the laws of the state of Texas, United States.

(f) Oaktree membership interest purchase agreement

On 18 March, 2024 the Company's subsidiaries, Diversified Production LLC and Diversified Gas & Oil Corporation entered into a membership interest purchase agreement (the "**Oaktree MIPA**") with OCM Denali INT Holdings PT, LLC, a subsidiary of Oaktree Capital Management, L.P. to acquire 100% of the limited liability company interests in OCM Denali Holdings, LLC the limited liability company interests, the ("**Oaktree Assets**") from Seller, which was completed on 7 June 2024. The gross purchase price for this acquisition amounted to $410 million and after customary purchase price adjustments, the net purchase price was approximately $377 million.

The Oaktree MIPA is governed by the laws of Delaware, United States.

(g) 2024 Oaktree Acquisition Sponsor Agreement

On 9 May 2024, the Company and Stifel entered into a sponsor agreement pursuant to which Stifel agreed to act as the Company's sponsor under the Listing Rules in connection with the acquisition of the Oaktree Assets and the publication of the circular as required under the Listing Rules (the "**Oaktree Acquisition Sponsor Agreement**"). The Oaktree Acquisition Sponsor Agreement also provided for the payment of certain fees and expenses by the Company to Stifel as sponsor.

Under the terms of the Oaktree Acquisition Sponsor Agreement, the Company agreed to provide certain customary warranties, representations and undertakings in favour of Stifel as sponsor in relation to, amongst other things, the accuracy of information in this document and other matters relating to the Group and the acquisition. The Company has also agreed to indemnify the Stifel as sponsor and its affiliates against, among other things, claims made against them or losses incurred by them in connection with the acquisition, subject to certain exceptions.

The Oaktree Acquisition Sponsor Agreement is governed by English law.

(h) Undeveloped Oklahoma Acreage Assets asset sale agreement

On 12 July 2023, the Company executed an Asset Purchase Agreement (the "**Oklahoma Acreage APA**") in connection with the divestment by the Company of certain undeveloped acreage in Oklahoma (the "**Undeveloped Oklahoma Acreage Assets**"), within the Company's Central Region, to an undisclosed buyer, which was completed on 12 July 2023. The cash consideration for this divestment amounted to approximately $16 million.

The Oklahoma Acreage APA is governed by the laws of Oklahoma, United States.

(i) Non-Operated Central Region Assets asset sale agreement

On 17 April 2023, the Company executed a Purchase and Sale Agreement (the "**Central Region PSA**") in connection with the divestment by the Company of certain non-operated wells in Oklahoma and Texas (the "**Non-Operated Central Region Assets**"), within the Company's Central Region, to an undisclosed buyer, which was completed on 27 June 2023. The cash consideration for this divestment amounted to approximately $40 million.

The Central Region PSA is governed by the laws of Texas, United States.

(j) ABS I Notes

In November 2019, the Group formed Diversified ABS LLC ("**ABS I**"), a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue BBB- rated asset-backed securities for an aggregate principal amount of $200 million at par. The ABS I Notes are secured by certain of the Group's upstream producing

Appalachian assets. Natural gas production associated with these assets was hedged at 85% at the close of the agreement with long-term derivative contracts.

Interest and principal payments on the ABS I Notes are payable on a monthly basis. During the years ended 31 December 2023, 2022 and 2021, the Group incurred $5.66 million, $7.11 million and $8.46 million of interest related to the ABS I Notes, respectively. The legal final maturity date is January 2037 with an amortising maturity of December 2029. The ABS I Notes accrue interest at a stated 5% rate per annum. The fair value of the ABS I Notes was approximately $94.52 million as of December 31, 2023.

In the event that ABS I has cash flow in excess of the required payments, ABS I is required to pay between 50% to 100% of the excess cash flow, contingent on certain performance metrics, as additional principal, with the remaining excess cash flow, if any, remaining with the Group. In particular, (a) with respect to any payment date prior to 1 March 2030, (i) if the debt service coverage ratio (the "**DSCR**") as of such payment date is greater than or equal to 1.25 to 1.00, then 25%, (ii) if the DSCR as of such payment date is less than 1.25 to 1.00 but greater than or equal to 1.15 to 1.00, then 50%, and (iii) if the DSCR as of such payment date is less than 1.15 to 1.00, the production tracking rate for ABS I is less than 80%, or the loan to value ratio is greater than 85%, then 100%, and (b) with respect to any payment date on or after 1 March 2030, 100%. During the year ended 31 December 2023, the Group paid $7.89 million in excess cash flow payments on the ABS I Notes.

(k) ABS II Notes

In April 2020, the Group formed Diversified ABS Phase II LLC ("**ABS II**"), a limited-purpose, bankruptcy-remote, wholly owned subsidiary, to issue BBB- rated asset-backed securities in an aggregate principal amount of $200 million. The ABS II Notes were issued at a 2.775% discount. The Group used the proceeds of $183.62 million, net of discount, capital reserve requirement, and debt issuance costs, to pay down its Credit Facility. The ABS II Notes are secured by certain of the Group's upstream producing Appalachian assets. Natural gas production associated with these assets was hedged at 85% at the close of the agreement with long-term derivative contracts.

The ABS II Notes accrue interest at a stated 5.25% rate per annum and have a maturity date of July 2037 with an amortising maturity of September 2028. Interest and principal payments on the ABS II Notes are payable on a monthly basis. During the years ended 31 December 2023, 2022 and 2021, the Group incurred $8.04 million, $9.29 million and $10.53 million in interest related to the ABS II Notes, respectively. The fair value of the ABS II Notes was approximately $119.52 million as of 31 December 2023.

In the event that ABS II has cash flow in excess of the required payments, ABS II is required to pay between 50% to 100% of the excess cash flow, contingent on certain performance metrics, as additional principal, with the remaining excess cash flow, if any, remaining with the Group. In particular, (a) (i) if the DSCR as of any payment date is less than 1.15 to 1.00, then 100%, (ii) if the DSCR as of such payment date is greater than or equal to 1.15 to 1.00 and less than 1.25 to 1.00, then 50%, or (iii) if the DSCR as of such payment date is greater than or equal to 1.25 to 1.00, then 0%; (b) if the production tracking rate for ABS II is less than 80.0%, then 100%, else 0%; (c) if the loan-to-value ratio ("**LTV**") as of such payment date is greater than 65.0%, then 100%, else 0%; (d) with respect to any payment date after 1 July 2024 and prior to 1 July 2025, if LTV is greater than 40.0% and ABS II has executed hedging agreements for a minimum period of 30 months starting July 2026 covering production volumes of at least 85% but no more than 95% (the "**Extended Hedging Condition**"), then 50%, else 0%; (e) with respect to any payment date after 1 July 2025 and prior to 1 October 2025, if LTV is greater than 40.0% or ABS II has not satisfied the Extended Hedging Condition, then 50%, else 0%; and (f) with respect to any payment date after 1 October 2025, if LTV is greater than 40.0% or ABS II has not satisfied the Extended Hedging Condition, then 100%, else 0%. During the year ended 31 December 2023, the Group made no excess cash flow payments on the ABS II Notes.

(l) ABS III Notes

In February 2022, the Group formed Diversified ABS III LLC ("**ABS III**"), a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue BBB rated asset-backed securities in an aggregate principal amount of $365 million at par. The ABS III Notes are secured by certain of the Group's upstream producing, as well as certain midstream, Appalachian assets.

The ABS III Notes accrue interest at a stated 4.875% rate per annum and have a final maturity date of April 2039 with an amortising maturity of November 2030. Interest and principal payments on the ABS III Notes are payable on a monthly basis. During the years ended 31 December 2023 and 2022, the Group incurred $14.52 million and $15.33 million in interest related to the ABS III Notes, respectively. The fair value of the ABS III Notes was approximately $250.16 million as of 31 December 2023.

In the event that ABS III has cash flow in excess of the required payments, ABS III is required to pay between 50% to 100% of the excess cash flow, contingent on certain performance metrics, as additional principal, with the remaining excess cash flow, if any, remaining with the Group. In particular, (a) (i) if the DSCR as of any payment date is greater than or equal to 1.25 to 1.00, then 0%, (ii) if the DSCR as of such payment date is less than 1.25 to 1.00 but greater than or equal to 1.15 to 1.00, then 50%, and (iii) if the DSCR as of such Payment Date is less than 1.15 to 1.00, then 100%; (b) if the production tracking rate for ABS III (as described in the ABS III Indenture) is less than 80%, then 100%, else 0%; and (c) if the LTV for ABS III is greater than 65%, then 100%, else 0%. During the year ended 31 December 2023, the Group made no excess cash flow payments on the ABS III Notes.

In connection with the issuance of the ABS III Notes, the Group retained an independent international provider of sustainability research and services to provide and maintain a "sustainability score" with respect to the Diversified PLC and to the extent such score is below a minimum threshold established at the time of issue of the ABS III Notes, the interest payable with respect to the subsequent interest accrual period will increase by five basis points. This score is not dependent on the Group meeting or exceeding any sustainability performance metrics but rather an overall assessment of the Group's corporate sustainability profile. Further, this score is not dependent on the use of proceeds of the ABS III Notes and there were no such restrictions on the use of proceeds other than pursuant to the terms of the Group's Credit Facility. The Group informs the ABS III note holders in monthly note holder statements as to any change in interest rate payable on the ABS III Notes as a result of the change in this sustainability score. As of 31 December 2023, the Group met or was in compliance with all sustainability-linked debt metrics.

In May 2024, the Group used proceeds from the ABS VIII Notes to repay the outstanding principal of the ABS III & ABS V Notes, thereby retiring the ABS III & ABS V Notes from the Group's outstanding debt and resulting in a loss on the early retirement of debt of $10.6 million. Diversified ABS III LLC & Diversified ABS V LLC were concurrently dissolved. The ABS VIII Notes are secured by the collateral previously securing the ABS III & V notes.

(m) ABS IV Notes

In February 2022, the Group formed Diversified ABS Phase IV LLC ("**ABS IV**"), a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue BBB rated asset-backed securities in an aggregate principal amount of $160 million at par. The ABS IV Notes are secured by a portion of the upstream producing assets acquired in connection with the Blackbeard Acquisition.

The ABS IV Notes accrue interest at a stated 4.95% rate per annum and have a final maturity date of February 2037 with an amortising maturity of September 2030. Interest and principal payments on the ABS IV Notes are payable on a monthly basis. During the year ended 31 December 2023 and 2022, the Group incurred $5.70 million and $6.24 million in interest related to the ABS IV Notes, respectively. The fair value of the ABS IV Notes was approximately $92.35 million as of 31 December 2023.

In the event that ABS IV has cash flow in excess of the required payments, ABS IV is required to pay between 50% and 100% of the excess cash flow, contingent on certain performance metrics, as additional principal, with the remaining excess cash flow, if any, remaining with the Group. In particular, (a) if the DSCR as of any payment date is greater than or equal to 1.25 to 1.00, then 0%, (ii) if the DSCR as of such payment date is less than 1.25 to 1.00 but greater than or equal to 1.15 to 1.00, then 50%, and (iii) if the DSCR as of such Payment Date is less than 1.15 to 1.00, then 100%; (b) if the production tracking rate for

ABS IV is less than 80%, then 100%, else 0%; and (c) if the LTV for ABS IV is greater than 65%, then 100%, else 0%.

In addition, in connection with the issuance of the ABS IV Notes, the Group retained an independent international provider of sustainability research and services to provide and maintain a "sustainability score" with respect to the Diversified Energy Company PLC and to the extent such score is below a minimum threshold established at the time of issue of the ABS IV Notes, the interest payable with respect to the subsequent interest accrual period will increase by five basis points. This score is not dependent on the Group meeting or exceeding any sustainability performance metrics but rather an overall assessment of the Group's corporate sustainability profile. Further, this score is not dependent on the use of proceeds of the ABS IV Notes and there were no such restrictions on the use of proceeds other than pursuant to the terms of the Group's Credit Facility. The Group informs the ABS IV note holders in monthly note holder statements as to any change in interest rate payable on the ABS IV Notes as a result of the change in this sustainability score. As of 31 December 2023, the Group met or was in compliance with all sustainability-linked debt metrics. During the year ended 31 December 2023, the Group made no excess cash flow payments on the ABS IV Notes.

(n) ABS V Notes

In May 2022, the Group formed Diversified ABS V LLC ("**ABS V**"), a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue BBB rated asset-backed securities in an aggregate principal amount of $445 million at par. The ABS V Notes are secured by a majority of the Group's remaining upstream assets in Appalachia that were not securitised by previous ABS transactions.

The ABS V Notes accrue interest at a stated 5.78% rate per annum and have a final maturity date of May 2039 with an amortising maturity of December 2030. Interest and principal payments on the ABS V Notes are payable on a monthly basis. During the year ended 31 December 2023 and 2022, the Group incurred $19.33 million and $14.32 million in interest related to the ABS V Notes, respectively. The fair value of the ABS V Notes was approximately $274.06 million as of 31 December 2023.

Based on whether certain performance metrics are achieved, ABS V could be required to apply 50% to 100% of any excess cash flow to make additional principal payments. In particular, (a) (i) if the DSCR as of any payment date is greater than or equal to 1.25 to 1.00, then 0%, (ii) if the DSCR as of such payment date is less than 1.25 to 1.00 but greater than or equal to 1.15 to 1.00, then 50%, and (iii) if the DSCR as of such payment date is less than 1.15 to 1.00, then 100%; (b) if the production tracking rate for ABS V is less than 80%, then 100%, else 0%; and (c) if the LTV for ABS V is greater than 65%, then 100%, else 0%. During the year ended 31 December 2023, the Group made no excess cash flow payments on the ABS V Notes.

In addition, a "second party opinion provider" certified the terms of the ABS V Notes as being aligned with the framework for sustainability-linked bonds of the International Capital Markets Association ("**ICMA**"), applicable to bond instruments for which the financial and/or structural characteristics vary depending on whether predefined sustainability objectives, or SPTs, are achieved. The framework has five key components (1) the selection of key performance indicators ("**KPIs**"), (2) the calibration of SPTs, (3) variation of bond characteristics depending on whether the KPIs meet the SPTs, (4) regular reporting of the status of the KPIs and whether SPTs have been met and (5) independent verification of SPT performance by an external reviewer such as an auditor or environmental consultant. Unlike the ICMA's framework for green bonds, its framework for sustainability-linked bonds do not require a specific use of proceeds.

The ABS V Notes contain two SPTs. The Group must achieve, and have certified by 28 April 2027 (1) a reduction in Scope 1 and Scope 2 GHG emissions intensity to 2.85 MT CO2e/MMcfe, and/or (2) a reduction in Scope 1 methane emissions intensity to 1.12 MT CO2e/MMcfe. For each of these SPTs that the Group fails to meet, or fail to have certified by an external verifier that the Group has not met, by 28

April 2027, the interest rate payable with respect to the ABS V Notes will be increased by 25 basis points. In each case, an independent third-party assurance provider will be required to certify the Group's performance of the above SPTs by the applicable deadlines. As of 31 December 2023, the Group met or was in compliance with all sustainability-linked debt metrics.

In May 2024, the Group used proceeds from the ABS VIII Notes to repay the outstanding principal of the ABS III & ABS V Notes, thereby retiring the ABS III & ABS V Notes from the Group's outstanding debt and resulting in a loss on the early retirement of debt of $10.6 million. Diversified ABS III LLC & Diversified ABS V LLC were concurrently dissolved. The ABS VIII Notes are secured by the collateral previously securing the ABS III & V notes.

(o) ABS VI Notes

In October 2022, the Group formed Diversified ABS Phase VI LLC ("**ABS VI**"), a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue, jointly with Oaktree, BBB+ rated asset-backed securities in an aggregate principal amount of $460 million ($236 million to the Group, before fees, representative of its 51.25% ownership interest in the collateral assets). The ABS VI Notes were issued at a 2.63% discount and are secured primarily by the upstream assets that were jointly acquired with Oaktree in the 2021 Tapstone acquisition. The Group recorded it's proportionate share of the note in its Consolidated Statement of Financial Position. In June 2024, the Group assumed Oaktree's proportionate debt of $132.5 million associated with the ABS VI Notes as part of the Oaktree Acquisition.

The ABS VI Notes accrue interest at a stated 7.50% rate per annum and have a final maturity date of November 2039 with an amortising maturity of October 2031. Interest and principal payments on the ABS VI Notes are payable on a monthly basis. During the year ended 31 December 2023 and 2022, the Group incurred $15.43 million and $3.30 million in interest related to the ABS VI Notes, respectively. The fair value of the ABS VI Notes was approximately $158.28 million as of 31 December 2023.

Based on whether certain performance metrics are achieved, ABS VI could be required to apply 50% to 100% of any excess cash flow to make additional principal payments. In particular, (a) (i) If the DSCR as of the applicable Payment Date is less than 1.15 to 1.00, then 100%, (ii) if the DSCR as of such Payment Date is greater than or equal to 1.15 to 1.00 and less than 1.25 to 1.00, then 50%, or (iii) if the DSCR as of such Payment Date is greater than or equal to 1.25 to 1.00, then 0%; (b) if the production tracking rate for ABS VI is less than 80%, then 100%, else 0%; and (c) if the LTV for ABS VI is greater than 75%, then 100%, else 0%. During the year ended 31 December 2023, the Group made no excess cash flow payments on the ABS VI Notes.

In addition, a "second party opinion provider" certified the terms of the ABS VI Notes as being aligned with the framework for sustainability-linked bonds of the ICMA, applicable to bond instruments for which the financial and/or structural characteristics vary depending on whether predefined sustainability objectives, or SPTs, are achieved. The framework has five key components (1) the selection of KPIs, (2) the calibration of SPTs, (3) variation of bond characteristics depending on whether the KPIs meet the SPTs, (4) regular reporting of the status of the KPIs and whether SPTs have been met and (5) independent verification of SPT performance by an external reviewer such as an auditor or environmental consultant. Unlike the ICMA's framework for green bonds, its framework for sustainability-linked bonds do not require a specific use of proceeds.

The ABS VI Notes contain two SPTs. The Group must achieve, and have certified by 28 May 2027 (1) a reduction in Scope 1 and Scope 2 GHG emissions intensity to 2.85 MT CO_2e/MMcfe, and/or (2) a reduction in Scope 1 methane emissions intensity to 1.12 MT CO_2e/MMcfe. For each of these SPTs that the Group fails to meet, or fail to have certified by an external verifier that it has met, by 28 May 2027, the interest rate payable with respect to the ABS VI Notes will be increased by 25 basis points. In each case, an independent third-party assurance provider will be required to certify the Group's performance of the above SPTs by the applicable deadlines. As of 31 December 2023, the Group met or was in compliance with all sustainability-linked debt metrics.

(p) ABS VII Notes

In November 2023, the Group formed DP Lion Equity Holdco LLC, a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue Class A and Class B asset-backed securities (collectively "**ABS VII**") which are secured by certain upstream producing assets in Appalachia. The ABS VII Class A Notes are rated BBB+ and were issued for an aggregate principal amount of $142 million. The ABS VII Class B Notes are rated BB- and were issued for an aggregate principal amount of $20 million.

The ABS VII Class A Notes accrue interest at a stated 8.243% rate per annum and have a final maturity date of November 2043 with an amortising maturity of February 2034. The ABS VII Class B Notes accrue interest at a stated 12.725% rate per annum and have a final maturity date of November 2043 with an amortising maturity of August 2032. Interest and principal payments on the ABS VII Class A and Class B Notes are payable on a monthly basis.

In December 2023, the Group divested 80% of the equity ownership in DP Lion Equity Holdco LLC to outside investors, generating cash proceeds of $30,000. The Group evaluated the remaining 20% interest in DP Lion Equity Holdco LLC and determined that the governance structure is such that the Group does not have the ability to exercise control, joint control, or significant influence over the DP Lion Equity Holdco LLC entity. Accordingly, this entity is not consolidated within the Group's financial statements for the year ended 31 December 2023.

(q) ABS VIII Notes

In May 2024, the Group formed Diversified ABS VIII LLC, a limited-purpose, bankruptcy-remote, wholly-owned subsidiary, to issue Class A-1 and Class A-2 asset-backed securities (collectively "**ABS VIII**"). The ABS VIII Class A-1 Notes are rated A and were issued for an aggregate principal amount of $400,000. The ABS VIII Class A-2 Notes are rated BBB+ and were issued for an aggregate principal amount of $210 million. The Group used the proceeds to repay the outstanding principal of the ABS III & ABS V Notes, thereby retiring the ABS III & ABS V Notes from the Group's outstanding debt. Diversified ABS III LLC & Diversified ABS V LLC were concurrently dissolved. The ABS VIII Notes are secured by the collateral previously securing the ABS III & ABS V Notes which includes certain of the Group's upstream producing, as well as certain midstream, Appalachian assets and the remaining upstream assets in Appalachia that were not securitised by previous ABS transactions.

The ABS VIII Class A-1 Notes accrue interest at a stated 7.076% rate per annum and have a final maturity date of May 2044 with an amortising maturity of March 2033. The Class A-2 Notes accrue interest at a stated 7.670% rate per annum and have a final maturity date of May 2044 with an amortising maturity of March 2033. Interest and principal payments on the ABS VIII Class A-1 and Class A-2 notes are payable on a monthly basis.

During the six months ended 30 June 2024, the Group incurred $3.9 million in interest related to the ABS VIII Notes. The fair value of the ABS VIII Notes was approximately $617.6 million as of 30 June 2024.

Based on whether certain performance metrics are achieved, ABS VIII is required to apply 25% to 100% of any excess cash flow to make additional principal payments. In particular, (a) (i) if the DSCR as of the applicable payment date is less than 1.45 to 1.00, then 100%, (ii) if the DSCR as of such payment date is greater than or equal to 1.45 to 1.00 and less than 1.50 to 1.00, then 50%, or (iii) if the DSCR as of such payment date is greater than or equal to 1.50 to 1.00, then 25%; (b) if the production tracking rate for ABS VIII is less than 80%, then 100%, else 25%; or (c) if the LTV for ABS VIII is greater than 75%, then 100%, else 25%.

During the six months ended 30 June 2024, the Group made no excess cash flow payments on the ABS VIII Notes.

(r) ABS IX Notes

In June 2024, the Group formed DP Mustang Holdco LLC, a limited-purpose, bankruptcy-remote, wholly-owned subsidiary (“**ABS IX**”, formerly the “**ABS Warehouse**”), to close on a bridge loan facility (the “**ABS Warehouse Facility**”). The initial draw on the ABS Warehouse Facility was $71 million, including $66.3 million in net proceeds, $3.1 million in restricted cash interest reserve and $1.6 million in debt issuance costs. The ABS Warehouse Facility is secured by certain producing assets previously collateralising the Credit Facility.

The ABS Warehouse Facility has an interest rate of SOFR plus an additional 3.75% and has a legal final maturity date of May 2029. Interest and principal payments on the ABS Warehouse Facility are payable on a monthly basis. The fair value of the ABS Warehouse Facility approximates the carrying value as of 30 June 2024.

In September 2024, the Group issued Class A and Class B asset-backed securities (collectively the “**ABS IX Notes**”) with a total principal amount of $76.5 million. The Class A Notes were issued with a total principal amount of $71 million, while the Class B Notes were issued with a total principal amount of $5.5 million. The proceeds from these issuances were used to repay the outstanding principal of the ABS Warehouse Facility, effectively retiring it from the Group’s outstanding debt and resulting in a loss on the early retirement of debt amounting to $1.6 million. The Class A Notes carry an annual interest rate of 6.555% and have an amortizing maturity date of December 2034. The Class B Notes carry an annual interest rate of 11.235% and have an amortizing maturity date of September 2030. Both interest and principal payments on the ABS IX Notes are made on a monthly basis.

(s) Oaktree Seller’s Note

In June 2024, the Group funded the purchase price of the Oaktree Transaction, in part, with deferred consideration in the form of an unsecured seller’s note from Oaktree (the “**Oaktree Seller’s Note**”). The Group issued $83.3 million in notes at a stated 8.0% rate per annum and have a final maturity date of December 2025, which was amended in October 2024 at a stated 9.0% rate per annum and a final maturity date of September 2026. Deferred interest and principal payments are now due on a monthly basis.

During the six months ended 30 June 2024, the Group incurred $0.6 million in interest related to the Oaktree Seller’s Note. The fair value of the Oaktree Seller’s Note approximates the carrying value as of 30 June 2024.

The Oaktree Seller’s Note contains certain customary representations and warranties and affirmative and negative covenants. As of 30 June 2024, the Group was in compliance with all covenants for the Oaktree Seller’s Note.

(t) Credit Facility

The Group maintains a revolving loan facility with a lending syndicate, the borrowing base for which is redetermined on a semi-annual, or as needed, basis. The Group’s wholly-owned subsidiary, DP RBL Co LLC, is the borrower under the Credit Facility. The borrowing base is primarily a function of the value of the natural gas and oil properties that collateralise the lending arrangement and will fluctuate with changes in collateral, which may occur as a result of acquisitions or through the establishment of ABS, term loan or other lending structures that result in changes to the Credit Facility collateral base.

In August 2022, the Group amended and restated the credit agreement governing its Credit Facility by entering into the A&R Revolving Credit Facility. The amendment enhanced the alignment with the Group’s stated sustainability initiatives by including sustainability performance targets (“**SPTs**”) similar to those included in the ABS III, IV, V and VI notes, extended the maturity of the Credit Facility to August 2026. In September 2023, the Group performed a semi-annual redetermination and the borrowing base was resized to $435 million, In November 2023, the borrowing base was resized to $305 million to reflect the movement of collateral for the issuance of the ABS VII Notes. In June 2024, the borrowing base was resized to $385 million to reflect the acquisition of Oaktree Capital assets and as at the Latest Practicable Date, the Company has received commitments for the increase of the borrowing base to $900 million at

Completion to reflect the Acquisition and it is expected that the maturity of the Credit Facility will also be extended to four years following Completion.

The Credit Facility has an interest rate of SOFR plus an additional spread that ranges from 2.75% to 3.75% based on utilisation. Interest payments on the Credit Facility are paid on a quarterly basis. Available borrowings under the Credit Facility were $134.82 million as of 31 December 2023 which includes the impact of $11.2 million in letters of credit issued to certain vendors.

The Credit Facility contains certain customary representations and warranties and affirmative and negative covenants, including covenants relating to: maintenance of books and records; financial reporting and notification; compliance with laws; maintenance of properties and insurance; and limitations on incurrence of indebtedness, liens, fundamental changes, international operations, asset sales, making certain debt payments and amendments, restrictive agreements, investments, restricted payments and hedging. The restricted payment provision governs the Group's ability to make discretionary payments such as dividends, share repurchases, or other discretionary payments. DP RBL Co LLC must comply with the following restricted payments test in order to make discretionary payments (i) leverage is less than 1.5x and borrowing base availability is >25% (ii) leverage is between 1.5x and 2.0x, free cash flow must be positive and borrowing base availability must be >20%, or (iii) when leverage exceeds 2.0x for DP RBL Co LLC, restricted payments are prohibited.

Additional covenants require DP RBL Co LLC to maintain a ratio of total debt to EBITDA of not more than 3.25 to 1.00 and a ratio of current assets (with certain adjustments) to current liabilities of not less than 1.00 to 1.00 as of the last day of each fiscal quarter. The fair value of the Credit Facility approximates the carrying value as of 31 December 2023.

The Credit Facility contains three SPTs which, depending on the Group's performance thereof, may result in adjustments to the applicable margin with respect to borrowings thereunder:

- GHG Emissions Intensity: The Group's consolidated Scope 1 emissions and Scope 2 emissions, each measured as MT CO_2e per MMcfe;
- Asset Retirement Performance: The number of wells the Group successfully retires during any fiscal year; and
- TRIR Performance: The arithmetic average of the two preceding fiscal years and current period total recordable injury rate computed as the Total Number of Recordable Cases (as defined by the Occupational Safety and Health Administration) multiplied by 200,000 and then divided by total hours worked by all employees during any fiscal year.

The goals set by the Credit Facility for each of these categories are aspirational and represent higher thresholds than the Group has publicly set for itself. The economic repercussions of achieving or failing to achieve these thresholds, however, are relatively minor, ranging from subtracting five basis points to adding five basis points to the applicable margin level in any given fiscal year.

An independent third-party assurance provider will be required to certify the Group's performance of the SPTs. As of 31 December 2023, the Group met or was in compliance with all sustainability-linked debt metrics.

(u) Term Loan I

In May 2020, the Group acquired DP Bluegrass LLC ("**Bluegrass**"), a limited-purpose, bankruptcy-remote, wholly owned subsidiary of the Group to enter into a securitised financing agreement for $160 million which was structured as a secured term loan. The Group issued the Term Loan I at a 1% discount, and used the proceeds of $158 million to fund the acquisition of the Carbon Assets and the EQT Assets. The Term Loan I is currently secured by certain producing assets acquired in connection with the Carbon, Blackbeard and Tapstone acquisitions.

The Term Loan I accrues interest at a stated 6.50% annual rate and has a maturity date of May 2030. Interest and principal payments on the Term Loan I are payable on a monthly basis. During the years ended 31 December 2023, 2022 and 2021, the Group incurred \$7.57 million, \$8.64 million and \$9.86 million in interest related to the Term Loan I, respectively. The fair value of the Term Loan I is approximately \$101.71 million as of 31 December 2023.

(v) CP Loan Facility

In August 2024, the Group formed DP Yellowjacket Holdco LLC, a wholly-owned subsidiary (the "**CP Loan Facility**"), to close on the Crescent Pass Acquisition. The initial draw on the CP Loan Facility was \$60 million, which has been increased to \$80 million in October 2024 in connection with the closing of the East Texas Assets acquisition. The refinanced facility consists of a term loan of approximately \$83 million and a revolving loan of approximately \$12 million. The CP Loan Facility is secured by substantially all the Crescent Pass Energy Assets and the East Texas Assets. The CP Loan Facility has an initial interest rate of SOFR plus an additional 4.00% and has a maturity date of August 2027. Interest and principal payments on the CP Loan Facility are payable on a monthly basis.

The Maverick Group

15.2 The following is a summary of those material contracts, not being contracts entered into in the ordinary course of business, which have been entered into by Maverick or any member of the Maverick Group within the two years immediately preceding the date of this document and of those other contracts, not being contracts entered into in the ordinary course of business by any member of the Maverick Group, that contain provisions under which Maverick and/or any member of the Maverick Group has an obligation or entitlement which is or may be material to the Group as at the date of this document:

(a) For details of the Agreement, the Registration Rights Agreement and Relationship Agreement, please see section 5 (*Key terms of the Acquisition*) of Part 1 (*Information on the Group*).

(b) For details of the East Texas Assets purchase and sale agreement, please see section 15.1(c) (*East Texas Assets purchase and sale agreement*) of Part 7 (Additional Information).

(c) Maverick Senior Secured Reserve-Based Credit Facility

On 27 January 2022, Maverick entered into an agreement with a syndicate of banks including JPMorgan Chase Bank acting as administrator, Royal Bank of Canada, Citizens Bank, KeyBank National Association acting as co syndication agents, RBC Capital Markets, and KeyBank Capital Markets (the "**Maverick Credit Facility**"). The agreement is for a maximum \$1 billion credit facility with an initial \$500 million borrowing base. The maturity date is 1 April 2026.

The Maverick Credit Facility limits the amounts the Maverick Group can borrow to a borrowing base amount determined by the lenders at their sole discretion based on their valuation of the Maverick Group's proved reserves and their internal criteria. The Maverick Group's obligations under the Maverick Credit Facility are collateralized by substantially all of the Maverick Group's oil and natural gas properties, including mortgage liens on oil and natural gas properties having at least 85% of the reserve value as determined by reserve reports.

The Maverick Credit Facility contains certain customary affirmative and negative covenants, including financial covenants requiring maintenance of the Consolidated Total Debt to EBITDAX Ratio to be less than 3.00 to 1.00 and a Current Ratio of no less than 1.00 to 1.00.

At the Maverick Group's election, borrowings under the Maverick Credit Facility may be made on an Alternate Base Rate ("**ABR**") or a Secured Overnight Financing Rate ("**SOFR**") basis plus an applicable margin. In connection with the Maverick Credit Facility, the applicable margins vary from 2.00% to 3.00% for ABR borrowings and 3.00% to 4.00% for SOFR borrowings depending on the borrowing base. In addition, the Maverick Group is also required to pay a commitment fee on the amount of any unused commitments at a rate of 0.50% per annum. Interest on ABR borrowings and the commitment fee are generally payable quarterly. As of 31 December 2023, the effective interest rate of the Maverick Credit Facility was 9.24%.

In June 2022, the Maverick Group entered into an amendment to the Maverick Credit Facility (the "**First Amendment**") which increased the borrowing base from the initial $500 million to $750 million. Each lender's borrowing capacity was increased with the exception of Goldman Sachs Bank, and the Maverick Group accounted for the First Amendment as a modification of debt. The Maverick Group incurred deferred financing costs of $2.6 million in relation to this amendment.

In October 2022, the Maverick Group entered into the second amendment to the Maverick Credit Facility (the "**Second Amendment**"), which increased the borrowing base to $1 billion. Each lender's borrowing capacity was increased with the exception of Texas Capital Bank, and the Maverick Group accounted for the Second Amendment as a modification of debt. The Maverick Group incurred deferred financing costs of $2.6 million in relation to this amendment.

In July 2023, the Maverick Group entered into the third amendment to the Credit Facility (the "**Third Amendment**"), which reduced the borrowing base from $1 billion to $750 million. Each lender's borrowing capacity was decreased, and the Maverick Group accounted for the Third Amendment as a modification of debt. Additionally, the Third Amendment allowed for a one-time cash distribution to the Maverick Group's equity holders not to exceed $10 million in aggregate through 30 September 2023. The Maverick Group did not incur deferred financing costs in relation to the Third Amendment.

In October 2023 in conjunction with the Maverick ABS Notes, the Maverick Group entered into the fourth amendment to the Credit Facility (the "**Fourth Amendment**"), which amended in its entirety the original Credit Facility. Pursuant to the Fourth Amendment, among other things, the borrowing base was reduced from $750 million to $350 million, and the respective reduced commitments of the various lending banks were reallocated among the continuing lenders to assign the exiting lenders' commitment. The Maverick Group accounted for the decreases in a lender's borrowing capacity as a modification and accounted for any lender that exited the credit facility as a debt extinguishment.

The Maverick Group incurred deferred financing costs of $5.6 million in relation to the Fourth Amendment. At 31 December 2023, the Maverick Group's borrowing base was $350 million, and the aggregate commitment of all lenders was $1 billion.

Unamortized debt issuance costs associated with the Maverick Credit Facility were $13.2 million as of 31 December 2023.

As of 31 December 2023, the Maverick Group was in compliance with its debt covenants under the Maverick Credit Facility.

(d) Maverick ABS Notes

On 26 October 2023, Maverick, through its consolidated subsidiaries, raised $640 million through an asset-backed securitisation financing transaction. Several new subsidiaries were created including MNR ABS Holdings I, LLC ("**Maverick ABS Holdings**") and MNR ABS Issuer I, LLC ("**Maverick ABS Issuer**").

Unbridled Resources, LLC ("**Unbridled**"), a primary operating subsidiary of Maverick, entered into an asset purchase agreement with Maverick ABS Issuer (the "**Purchase and Sale Agreement**"), pursuant to which Unbridled agreed to sell and transfer to Maverick ABS Issuer certain operated and non-operated oil and natural gas wells and all oil and natural gas leases, subleases and leasehold covering such wells (the "**Maverick ABS Assets**" and such transfer, the "**Maverick ABS Asset Transfer**") for a purchase price of $640 million, of which $630 million was cash and $10 million was a non-cash note payable. In connection with the Maverick ABS Asset Transfer, Maverick Asset Holdings LLC ("**MAH**") transferred by novation to Maverick ABS Issuer certain hedge agreements ("**Maverick Assumed Hedges**").

In connection with the transaction, Maverick ABS Issuer entered into an indenture with UMB Bank, N.A. as indenture trustee (the "**Indenture Trustee**") (the "**Indenture**") to which Maverick ABS Issuer issued (a) $640 million aggregate principal amount of Series 2023-1 Notes, consisting of (i) $285 million aggregate principal amount of its 8.121% Series 2023-1 Notes, Class A-1 Notes due December 2038, (ii) $260 million aggregate principal amount of its 8.946% Series 2023-1 Notes, Class A-2 Notes due December 2038 and (iii) $95 million aggregate principal amount of its 12.436% Series 2023-1 Notes, Class B Notes due December 2038 (collectively, the "**Maverick ABS Notes**") and (b) pledged the Maverick ABS Assets to the Indenture Trustee to secure Maverick ABS Issuer's obligations under the Indenture (the "**Maverick ABS Financing Transaction**").

In addition, the following events occurred in connection with the Maverick ABS Financing Transaction: (i) $10 million of the Maverick ABS Notes were issued to Maverick, (ii) a holdback of $5.4 million related to consents not received at the date of the transaction which is reflected as restricted cash, (iii) a Liquidity Reserve Account was established for $23.6 million and is reflected as restricted cash, (iv) $260 million was an equity distribution and (v) repaid $300 million for the Maverick Credit Facility held by MAH.

The Maverick ABS Notes are secured by certain oil and natural gas interests in currently producing oil and natural gas wells and other assets. The Maverick ABS Notes accrue interest at the respective stated per annum rates and have a final maturity date of 15 December 2038. Interest and principal payments are payable on a monthly basis. During the period ended 31 December 2023, the Maverick Group incurred $10.3 million of interest related to the Maverick ABS Notes.

The Maverick ABS Notes are subject to a series of covenants and restrictions customary for transactions of this type, including (i) that the Maverick ABS Issuer maintains specified reserve accounts to be used to make required interest payments in respect of the Maverick ABS Notes, (ii) provisions relating to optional and mandatory prepayments and the related payment of specified amounts, including specified make-whole payments under certain circumstances, (iii) certain indemnification payments in the event, among other things, that the assets pledged as collateral are used in stated ways defective or ineffective, (iv) covenants related to recordkeeping, access to information and similar matters, and (v) the Maverick ABS Issuer will comply with all laws and regulations which it is subject to. The Maverick ABS Notes are also subject to customary accelerated amortization events provided for in the indenture, including events tied to failure to maintain stated debt service coverage ratios, failure to maintain certain production metrics, and event of default and the failure to repay or refinance the Maverick ABS Notes on the applicable scheduled maturity date. The Maverick ABS Notes are subject to certain customary events of default, including events relating to non-payment of required interest, principal, or other amounts due on or with respect to the Maverick ABS Notes, failure to comply with covenants within certain time frames, certain bankruptcy events, breaches of specified representations and warranties, failure of security interests to be effective and certain judgments.

Under the Indenture, Maverick must maintain the following financial covenants determined as of the last day of the quarter: i) Aggregate Debt Service Coverage Ratio (DSCR) less than 1.05, and ii) Senior DSCR less than 1.25.

As of 31 December 2023, the Maverick Group was in compliance with its covenants under the Maverick ABS Notes.

16. Litigation

The Group

There are no, and have not been, any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) which may have, or have had during the 12 months preceding the date of this document, a significant effect on the Company's or the Group's financial position or profitability.

The Maverick Group

There are no, and have not been, any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which Maverick is aware) which may have, or have had during the 12 months preceding the date of this document, a significant effect on Maverick's or the Maverick Group's financial position or profitability.

17. Working capital

The Company is of the opinion that, taking into account the facilities currently committed to the Group and the net proceeds from the Capital Raise (including if the Over-Allotment Option is not exercised), each of (i) the Group, and (ii) the Enlarged Group has sufficient working capital for its present requirements, that is for at least 12 months from the date of this document.

18. No significant change

The Group

Save as set out below, there has been no significant change in the financial position or performance of the Group since 30 June 2024, being the end of the last financial period for which financial information of the Group has been published:

(i) on 15 August 2024, the Company completed the acquisition of the Crescent Pass Assets, as described in further detail in section 10 (*Acquisitions and Consolidation*) in Part 1 (Information on the Group) of this document;

(ii) on 30 October 2024, the Company completed acquisition of the East Texas Assets, as described in further detail in section 10 (Acquisitions and Consolidation) in Part 1 (Information on the Group) of this document;

(iii) during July and August 2024, the Company purchased 561,629 ordinary shares in the capital of the Company.

The Maverick Group

Save as set out below, there has been no significant change in the financial position or performance of the Maverick Group since 30 September 2024, being the end of the last financial period for which financial information of the Maverick Group has been published:

(i) on 30 October 2024, Maverick completed the sale of the East Texas Assets, as described in further detail in section 10 (*Acquisitions and Consolidation*) in Part 1 (Information on the Group) of this document.

19. Regulatory Disclosure

19.1 The Company regularly arranges the publication of announcements through an RIS system and on the Company's website. This section contains a summary of the information disclosed under the UK Market Abuse Regulation over the last 12 months which is relevant as at the date of this document. In addition to the RIS system, full announcements can be accessed on the webpage of the Company at https://ir.div.energy/.

Inside information

(a) On 27 January 2025, the Company announced the proposed Acquisition.

(b) On 12 November 2024, the Company announced that the Board has declared an interim dividend of 29 cents per share in respect of 3Q24 for the three-month period ended 30 September 2024.

(c) On 20 August, the Company announced the execution of a conditional purchase and sale agreement in connection with the East Texas Assets Acquisition.

(d) On 15 August 2024, the Company announced that the Board has declared an interim dividend of 29 cents per share in respect of 2Q24 for the three-month period ended 30 June 2024.

(e) On 10 July, the Company announced that it had entered into a conditional purchase and sale agreement for the acquisition of high-working interest, operated natural gas properties and related facilities located within eastern Texas from Crescent Pass Energy.

(f) On 9 May 2024, the Company announced that the Board has declared an interim dividend of 29 cents per share in respect of 1Q24 for the three-month period ended 31 March 2024.

(g) On 5 April 2024, the Company provided an update that it is entered into an engagement with Peel Hunt to undertake share buybacks under the Company's share buyback programme.

(h) On 19 March 2024, the Company announced its final audited results for the year ended 31 December 2023. Additionally, the Company also announced that it had entered into a conditional agreement with Oaktree Capital Management, L.P. for the strategic acquisition of working interests in certain assets operated in the Central Region. Further, the Company also announced a revised capital allocation framework designed to strengthen the balance sheet and provide sustainable shareholder returns.

Dealings by persons discharging managerial responsibilities and their persons closely associated

(a) On 30 May 2024, the Company announced that Martin Thomas, Independent Non-Executive Vice Chair of the Board, acquired through the market 565 ordinary shares at an average price of 1,104.35 pence per ordinary share.

(b) On 28 May 2024, the Company announced that Sylvia Kerrigan, the former Senior Independent Non-Executive Director, acquired through the market 820 ordinary shares at an average price of £11.0737 per ordinary share, Kathryn Z. Klaber, Independent Non-Executive Director, acquired through the market 820 ordinary shares at an average price of $14.2865 per ordinary share, Sandra Stash, Independent Non-Executive Director acquired through the market 818 ordinary shares at an average price of $14.29 per ordinary share and David Turner, Independent Non-Executive Director acquired through the market 1764 ordinary shares at an average price of $14.1514 per ordinary share.

(c) On 22 March 2024, the Company announced the vesting of certain Performance Share Units and Restricted Stock Units previously awarded to certain PDMRs, including Rusty Hutson, Bradley Gray and Benjamin Sullivan, resulting in a change to previously disclosed PDMR holdings of Ordinary Shares.

19.2 Save for the matters described above, the Company has not made any further publications in accordance with the UK Market Abuse Regulation in the last 12 months which are relevant at the date of this document.

20. Miscellaneous

20.1 PricewaterhouseCoopers LLP, whose business address is 1 Embankment Place, London WC2N 6RH, United Kingdom, and who is a member firm of the Institute of Chartered Accountants in England and Wales, has given and has not withdrawn its written consent to the inclusion in Section B of Part 4 ("*Unaudited Pro Forma Financial Information"*) of this document of its report on the unaudited pro forma financial information and has authorised the contents of that report as part of this Prospectus for the purposes of Prospectus Regulation Rule 5.3.2R(2)(f) and item 1.3 of Annex 3 of Commission Delegated Regulation (EU) 2019/980 as it forms part of UK domestic law by virtue of the European Union (Withdrawal) Act 2018. PricewaterhouseCoopers LLP is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales (under registration number OC303525) and the Financial Reporting Council.

20.2 Statutory consolidated accounts of the Company have been delivered to the Registrar of Companies in respect of the financial year ended 31 January 2023 and an independent auditors' report was made on those accounts. The auditors' reports did not include a reference to any matter to which the auditors drew attention by way of emphasis without qualifying the opinion; and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

20.3 The Group H1 2024 Financial Statements have been approved by the Board on 13 August 2024. These financial statements do not comprise statutory accounts within the meaning of section 434 of the Companies Act 2006, and should be read in conjunction with the Group 2023 Financial Statements.

21. Mandatory Bids, Squeeze-Out and Sell-out rules

21.1 Mandatory Bid

The Takeover Code applies to the Company. Under Rule 9 of the Takeover Code, if an acquisition of interests in shares were to increase the aggregate holding of the acquirer and its concert parties to interests in shares carrying 30 per cent. or more of the voting rights in the Company, the acquirer and, depending on circumstances, its concert parties would be required (except with the consent of the Takeover Panel) to make a cash offer for the outstanding shares in the Company at a price not less than the highest price paid for interests in shares by the acquirer or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of interests in shares by a person holding (together with its concert parties) shares carrying between 30 per cent. and 50 per cent. of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the total voting rights in the Company.

21.2 Squeeze-Out

Under the Companies Act 2006, if a "takeover offer" (as defined in section 974 of the Companies Act 2006) is made for the shares and the offeror were to acquire, or unconditionally contract to acquire, not less than 90 per cent. in value of the shares to which the offer relates and not less than 90 per cent. of the voting rights carried by the shares to which the offer relates, it could, within three months of the last day on which its takeover offer can be accepted, compulsorily acquire the remaining 10 per cent. The offeror would do so by sending a notice to outstanding shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would execute a transfer of the outstanding shares in its favour and pay the consideration for the outstanding shares to the Company, which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose shares are compulsorily acquired under this procedure must, in general, be the same as the consideration that was available under the takeover offer.

21.3 Sell-Out

The Companies Act 2006 also gives minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer relates to all the shares and, at any time before the end of the period within which the offer can be accepted, the offeror holds or has agreed to acquire not less than 90 per cent. in value of the shares and not less than 90 per cent. of the voting rights carried by the shares, any holder of shares to which the offer relates who has not accepted the offer could, by a written communication to the offeror, require it to acquire those shares. The offeror is required to give any shareholder notice of his/her 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 later, three months from the date on which notice is served on shareholders notifying them of their sell-out rights. If a shareholder exercises his/her sellout rights, the offeror is entitled and bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

22. Documents incorporated by reference

22.1 The contents of the Group's website, unless specifically incorporated by reference, any website mentioned in this document or any website directly linked to these websites have not been verified and do not form part of this document, and prospective investors should not rely upon them.

22.2 Details of documentation incorporated into this document by reference are explained in Part 8 ("*Documents Incorporated by Reference*").

23. Documents available for inspection

23.1 Copies of the following documents will be available for inspection during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of this document until the latest of the Equity Raise Shares Admission, the Over-Allotment Shares Admission and Consideration Shares Admission at the Company's registered office at 1 King Street, London, EC2V 8AU, United Kingdom:

(a) the Articles;

(b) the 2023 Annual Report, including the Alternative Performance Measures as set out in the 2023 Annual Report;

(c) the H1 2024 Interim Report, including the Alternative Performance Measures as set out in the H1 2024 Interim Report;

(d) a copy of the letter of consent referred to in paragraph 20.1 of this Part 7 ("*Additional Information*"); and

(e) this document.

Copies of the above documents will also be published on the Company's website at https://ir.div.energy/.

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 for the purposes of the UK Prospectus Regulation Rules. 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).

These documents incorporated by reference are available for inspection in accordance with paragraph 23 of Part 7 ("*Additional Information*") of this document.

Reference Document	Information Incorporated by reference	Page number in the reference documents
2023 Annual Report......................	Independent Auditors' Report to the members of Diversified Energy Company PLC	134 - 142
	Consolidated Statement of Comprehensive Income	143
	Consolidated Statement of Financial Position	144
	Consolidated Statement of Changes in Equity	145
	Consolidated Statement of Cash Flows	146
	Notes to the Group Financial Statements	147-195
	Company Statement of Financial Position	196
	Company Statement of Changes in Equity	197
	Notes to the Company Financial Statements	198-203
	Alternative Performance Measures (Unaudited)	206-208
H1 2024 Interim Report...............	Independent Review Report to Diversified Energy Company PLC	14
	Condensed Consolidated Statement Comprehensive Income	15
	Condensed Consolidated Statement of Financial Position	16
	Condensed Consolidated Statement of Changes in Equity	17
	Condensed Consolidated Statement of Cash Flows	18
	Notes to the Interim Condensed Consolidated Financial Statements	19-41
Circular...	Unaudited Historical Financial Information relating to the Oaktree Assets	18-20

Part 9
TECHNICAL TERMS

"**basin**"	a large natural depression on the earth's surface in which sediments accumulate;
"**barrels**" or "**Bbl**"	a unit of volume measurement used for petroleum and its products; for a typical crude oil 7.3 barrels (equal to 42 US gallons) = 1 tonne; 6.29 barrels = 1 cubic metre;
"**Boe**"	barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 6,000 cf of natural gas;
"**btu**"	British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit under specific conditions;
"**cf**"	cubic feet;
"**CO2e**"	carbon dioxide equivalent;
"**drilling**"	any activity related to drilling pad make-ready costs, rig mobilisation and creating a wellbore in order to facilitate the ultimate production of hydrocarbons;
"**field**"	an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations;
"**GHG**"	greenhouse gas emissions;
"**Henry Hub**"	a natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts;
"**Mcf**"	thousand standard cubic feet of natural gas;
"**Mcfe**"	thousand cubic feet of natural gas equivalent;
"**Mbbl**"	thousand barrels of oil;
"**MMboe**"	millions of barrels of oil equivalent;
"**MMbtu**"	million btus;
"**MMcf**"	million standard cubic feet of natural gas;
"**natural gas**"	hydrocarbons that at a standard temperature of sixty degrees Fahrenheit (60ºF) and a standard pressure of one atmosphere are in a gaseous state, including wet mineral gas and dry mineral gas, casing head gas, residual gas remaining after separation treatment, processing, or extraction of liquid hydrocarbons;
"**NGL**"	natural gas liquids, such as ethane, propane, butane and natural gasoline that are extracted from natural gas production streams;
"**oil equivalent**"	international standard for comparing the thermal energy of different fuels;

"**plugging**" .... the plug and abandonment process of a well for retirement at the end of its productive life cycle through pumping of cement into the well to cover and isolate the zones that produce, have produced, or contain hydrocarbons;

"**PV**" or "**present value**" .... the present value of a future sum of money or stream of cash flows given a specific rate of return e.g. PV-18 means the present value at a discount rate of eighteen per cent. (18 per cent.);

"**PV-10**" .... the present value of a future sum of money or stream of cash flows given a discount rate 10 per cent. PV-10 is a customary valuation metric used in the valuation of future cash flows for oil and gas reserves;

"**proved developed producing Reserves**" or "**PDP**" .... proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market. Reserves that can be recovered through wells with existing equipment and operating methods;

"**proved reserves**" .... the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions;

"**proved undeveloped reserves**" or "**PUD**"... proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion;

"**recompletion**"................................. the completion for production of an existing well bore in another formation from that in which the well has been previously completed;

"**recoverable**" .... a description of hydrocarbon reserves that identifies them as technically or economically feasible to extract;

"**reserves**" .... 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;

"**reservoir**".. a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system;

"**resources**"....................................... deposits of naturally occurring hydrocarbons which, if recoverable, include those volumes of hydrocarbons either yet to be found (prospective) or if found the development of which depends upon a number of factors (technical, legal and/or commercial) being resolved (contingent);

"**undeveloped acreage**" .... lease acreage on which wells have not been participated in or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves;

"**working interest**"........................... a cost bearing interest which gives the owner the right to drill, produce, and conduct oil and gas operations on the property, as well as a right to a share of production therefrom.

Part 10
DEFINITIONS

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

"**£**" or "**Pounds Sterling**" or "**Sterling**" or "**GBP**"	pounds sterling, the lawful currency of the United Kingdom;
"**2023 Annual Report**"	the annual report published by the Group for the year ended 31 January 2023;
"**2024 AGM**"	the annual general meeting of the Company held on 10 May 2024;
"**Acquisition**"	the proposed acquisition of the Maverick Group by the Group, as more fully described in Section 5 of Part 1 of this document;
"**Admission and Disclosure Standards**"	the requirements contained in the publication "Admission and Disclosure Standards" published by the London Stock Exchange in October 2018 containing, among other things, the admission requirements to be observed by companies seeking admission to trading on the Main Market for listed securities;
"**Agreement**"	the agreement dated 24 January 2025 between, among other, the Company and Maverick in connection with the Acquisition;
"**Articles**"	the articles of association of the Company from time to time;
"**Board**"	the board of directors of the Company;
"**Capital Raise Shares Admission**"	admission of the Capital Raise Shares to the equity shares (commercial companies) category of the Official List and admission to trading of the Capital Raise Shares on the Main Market becoming effective;
"**Capital Raise Shares**"	the Equity Raise Shares and the Over-Allotment Shares;
"**Capital Raise**"	the Equity Raise and the Over-Allotment Option, as more fully described in Section 4 of Part 1 of this document;
"**certificated**" or "**in certificated form**"	a share or other security which is not in uncertificated form (that is, not in CREST);
"**Circular**"	the circular dated 9 May 2024 published by the Company in connection with the Oaktree Acquisition;
"**Circular Oaktree Financial Information**"	the financial information relating to the revenues and direct expenses relating to the Oaktree Assets for the two years ended 31 December 2022 and 31 December 2023 as included in Part 4 of the Circular;
"**Companies Act 2006**" or "**Act**"	the Companies Act 2006 (as amended);
"**Company**"	Diversified Energy Company PLC;
"**Completion**"	the completion of the Acquisition in accordance with the Agreement;
"**Consideration Shares Admission**"	admission of the Consideration Shares to the equity shares (commercial companies) category of the Official List and admission to trading of the Consideration Shares on the Main Market becoming effective;

"**Consideration Shares**"	up to 33,954,491 new Ordinary Shares to be allotted and issued pursuant to the Acquisition;
"**Crescent Pass Acquisition**"	the acquisition by the Group of high-working interest, operated natural gas properties and related facilities located within eastern Texas, as completed in August 2024;
"**CREST Regulations**"	the Uncertificated Securities Regulations 2001 (SI 2001 / 3755);
"**CREST**"	the relevant system (as defined in the Uncertificated Securities Regulations 2001 (SI 2001/3755)) in respect of which Euroclear UK & International Limited is the Operator (as defined in such Regulations) in accordance with which securities may be held and transferred in uncertificated form;
"**Daily Official List**"	the daily record setting out the prices of all trades in shares and other securities conducted on the London Stock Exchange;
"**DIs**"	the depositary interests operated by Computershare Investor Services PLC through CREST representing Ordinary Shares;
"**Depositary**"	Computershare Trust Company N.A. in its capacity as the depositary;
"**DGOC**"	Diversified Gas & Oil Corporation;
"**DI Custodian**"	Computershare Trust Company N.A. in its capacity as custodian for the DI Depositary;
"**DI Deed**"	the deed poll made by the DI Depositary constituting the DIs;
"**DI Depositary**"	Computershare Investor Services PLC, in its capacity as the issuer of DIs;
"**Directors**"	the directors of the Company, whose names are set out in paragraph 6 of Part 7 of this document;
"**Dividend Allowance**"	a £1,000 allowance which will be taxed at a nil rate;
"**DTC**"	the Depository Trust Company;
"**DTRs**"	the Disclosure Guidance and Transparency Rules made by the FCA pursuant to Part 6 of FSMA;
"**East Texas Assets**"	the operated natural gas properties located within eastern Texas acquired by the Group, as more fully described in Section 10 of Part 1 of this document;
"**East Texas Assets Acquisition**"	the acquisition of the East Texas Assets, as more fully described in Section 10 of Part 1 of this document;
"**EBITDA**"	earnings before interest, tax, depreciation and amortisation;
"**EIG**"	EIG Management Company, LLC;
"**Enlarged Group**"	the Group, following completion of the Acquisition;
"**Enlarged Issued Share Capital**"	the Ordinary Shares in issue following completion of the Capital Raise (assuming that the Over-Allotment Option is exercised in full) and the Acquisition (assuming that the maximum number of Consideration Shares are allotted and issued);

"**Equity Raise**"	the issue of 8,500,000 new Ordinary Shares to raise net proceeds of approximately £93.9 million ($118.3 million) as more fully described in Section 4 of Part 1 of this document;
"**Equity Raise Shares**"	8,500,000 new Ordinary Shares issued and allotted pursuant to the Equity Raise;
"**Equity Raise Shares Admission**"	admission of the Equity Raise Shares to the equity shares (commercial companies) category of the Official List and admission to trading of the Consideration Shares on the Main Market becoming effective;
"**Euroclear UK & International**"	Euroclear UK & International Limited, the operator of CREST;
"**FCA**"	the Financial Conduct Authority;
"**FSMA**"	the UK Financial Services and Markets Act 2000 (as amended);
"**Group**"	the Company and its subsidiary undertakings prior to completion of the Acquisition;
"**Group 2023 Financial Statements**"	the audited consolidated financial statements of the Group as at and for the year ended 31 December 2023;
"**Group H1 2024 Financial Statements**"	the unaudited interim condensed consolidated financial statements of the Group as at and for the six-month period ended 30 June 2024;
"**H1 2025**"	the six-month period ended 30 June 2025;
"**H1 2024 Interim Report**"	the interim report published by the Company on 15 August 2024 for the six-month period ended 30 June 2024;
"**HMRC**"	HM Revenue & Customs;
"**IFRS**"	the UK-adopted International Financial Reporting Standards and their interpretations issued by the International Accounting Standards Board;
"**ISIN**"	International Securities Identification Number;
"**Latest Practicable Date**"	18 February 2025, being the latest practicable date before publication of this document;
"**LEI**"	Legal Entity Identifier;
"**Listing Rules**"	the UK Listing rules made by the FCA under the FSMA;
"**London Stock Exchange**"	London Stock Exchange plc;
"**Main Market**"	the London Stock Exchange's main market for listed securities;
"**Maverick**"	Maverick Natural Resources, LLC;
"**Maverick Credit Facility**"	the credit facility for the Maverick Group, as more fully described in Section 15.2(c) of Part 7 (*Additional Information*) of this document;
"**Maverick Group**"	Maverick, together with its subsidiaries and subsidiary undertakings;
"**New Shares Admission**"	the Capital Raise Shares Admission and the Consideration Shares Admission;
"**New Shares**"	the Capital Raise Shares and the Consideration Shares;
"**NYSE**"	New York Stock Exchange;

"**Oaktree Acquisition**"	the acquisition by the Group of the proportionate working interest in certain assets within the Company's Central Region from Oaktree Capital Management L.P., as completed in June 2024;
"**Oaktree 2023 Financial Information**"	the financial information relating to the revenues and direct expenses relating to the Oaktree Assets presented in section 10 (*Acquisitions and Consolidation – Oaktree Acquisition*) of Part 1 (*Information on the Group*) of this document for the financial year ended 31 December 2023;
"**Oaktree Q1 2024 Financial information**"	the financial information relating to the revenues and direct expenses relating to the Oaktree Assets presented in section 10 (*Acquisitions and Consolidation – Oaktree Acquisition*) of Part 1 (*Information on the Group*) of this document for the three-month period ended 31 March 2024;
"**Official List**"	the Official List maintained by the FCA;
"**Options**"	the grant of options to acquire ordinary shares in the Company;
"**Ordinary Shares**"	the ordinary shares of £0.20 each in the capital of the Company;
"**Over-Allotment Option**"	the option granted by the Company to the Underwriters exercisable for 30 days from the date of the underwriting agreement to subscribe for up to 850,000 new Ordinary Shares, at the price at which the new Ordinary Shares are issued and allotted in the Capital Raise;
"**Over-Allotment Shares**"	up to 850,000 new Ordinary Shares that may be issued upon exercise of the Over-Allotment Option;
"**Over-Allotment Shares Admission**"	admission of the Over-Allotment Shares to the equity shares (commercial companies) category of the Official List and admission to trading of the Over-Allotment Shares on the Main Market becoming effective;
"**RSUs**"	the restricted stock units;
"SDRT"	Stamp duty reserve tax;
"SEC"	the U.S. Securities and Exchange Commission;
"**Shareholders**"	the holders of the Ordinary Shares;
"SOFR"	the Secured Overnight Financing Rate;
"**TTM**"	trailing twelve months;
"**Transactions**"	the Capital Raise and the Acquisition;
"**UK Market Abuse Regulation**"	the UK 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 UK law by virtue of the European Union (Withdrawal) Act 2018, as amended from time to time;
"**UK Prospectus Regulation Rules**"	the prospectus regulation rules of the FCA made under section 73A of the FSMA;
"**UK Prospectus Regulation**"	the UK version of the Prospectus Regulation (EU) No 2017/1129 which forms part of UK law by virtue of the European Union (Withdrawal) Act 2018;
"**U.S. GAAP** or **"GAAP"**	the accounting principles generally accepted in the United States of America;

"**uncertificated**" **or** "**in uncertificated form**"	recorded in the register of members as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST;
"**United Kingdom**" or "**UK**"	the United Kingdom of Great Britain and Northern Ireland;
"**United States**" or "**US**"	the United States of America, its territories and possessions, any state of the United States of America, and the District of Columbia;
"**US Securities Act**"	the US Securities Act of 1933, as amended; and
"**US$**" or "**$**" or "**US dollars**"	US dollars, the lawful currency of the United States.