THIS DOCUMENT AND ACCOMPANYING DOCUMENTS ARE IMPORTANT AND REQUIRE YOUR IMMEDIATE ATTENTION. If you are in any doubt as to the action you should take, you are recommended to seek your own financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 (as amended) (the "FSMA") if you are resident in the United Kingdom or, if not, from another appropriately authorised independent financial adviser.

If you sell or have sold or otherwise transferred or do transfer all your Ordinary Shares and/or Depositary Interests in the Company, please forward this document together with the accompanying documents that you receive as soon as possible to the purchaser or transferee, or the stockbroker, bank or other agent through whom the sale or transfer was effected, for transmission to the purchaser or transferee except that, subject to certain exceptions, such documents should not be forwarded or transmitted into any jurisdiction where to do so might constitute a violation of local securities law or regulation. If you sell or have sold or otherwise transferred part of your holding of Ordinary Shares and/or Depositary Interests in the Company, please retain this document and the accompanying documents and consult the stockbroker, bank or other agent through whom the sale or transfer was effected.

The distribution of this document and/or any accompanying documents in certain jurisdictions outside the United Kingdom may be restricted by the law and therefore persons into whose possession this document and/or any accompanying documents come should inform themselves about and observe such restrictions. Any failure to comply with any of these restrictions may constitute a violation of the securities law of any such jurisdiction.

DIVERSIFIED
energy

DIVERSIFIED ENERGY COMPANY PLC

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

Proposed acquisition of the Target Assets from OCM Denali INT Holdings PT, LLC

Circular to Shareholders
and
Notice of General Meeting

The whole of the text of this document, including any accompanying documents and any documents incorporated by reference, should be read in its entirety. Your attention is drawn to the letter from the Chair of the Company which is set out in Part 1 ("*Letter from the Chair*"), and which contains a recommendation from the Board that you vote in favour of the Resolution to be proposed at the General Meeting. Your attention is also drawn, in particular, to Part 2 (*Risk Factors)* of this document which sets out certain risks and other factors that should be taken into account by Shareholders when deciding on what action to take in relation to the Acquisition.

Notice of a General Meeting of the Company to be held at the offices of FTI Consulting, 200 Aldersgate, Aldersgate Street, London, EC1A 4HD, United Kingdom at 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 28 May 2024 is set out at the end of this document.

Shareholders will find enclosed a Form of Proxy for use at the General Meeting. Depositary Interest Holders will need to complete a Form of Instruction or submit their voting instruction via the CREST voting system as set out in the 'Notes to the Notice of General Meeting' section. To be valid for use at the General Meeting, the Form of Proxy must be completed and returned, in accordance with the instructions printed thereon, to Broadridge Financial Solutions, Inc. at Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717 as soon as possible and, in any event, to arrive by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024.

The completion and return of a Form of Proxy will not preclude Shareholders from attending and voting in person at the General Meeting should they subsequently wish to do so. The Form of Instruction should be returned to the

Depositary, Computershare Investor Services PLC, the Pavilions, Bridgwater Road, Bristol, BS99 6ZY, United Kingdom by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 22 May 2024. Depositary Interest Holders wishing to attend the meeting in person should refer to the 'Notes to the Notice of General Meeting' section for instructions on how to attend.

The Company is a "foreign private issuer" within the meaning of Rule 3b-4 of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), and as a result, the Company is not required to comply with proxy solicitation rules under U.S. federal securities laws. Brokers holding Shares must vote according to specific instructions they receive from the beneficial owners of those Shares. If brokers do not receive specific instructions, brokers may in some cases vote the Shares in their discretion, but are not permitted to vote on certain proposals and may elect not vote on any of the proposals unless you provide voting instructions. Thus, the Company strongly encourages you to provide instructions to your broker to vote your Shares and exercise your right as a Shareholder. As such, only those votes cast "FOR" or "AGAINST" are counted for the purposes of determining the number of votes cast in connection with the proposals set out in the Notice of the General Meeting. Abstentions and broker non-votes have no effect on the outcome of the resolution proposed at the General Meeting.

If you hold your interest through a broker, bank, or nominee (or similar), you should normally receive directions from such broker, bank, or nominee (or similar) on how to (electronically or in person) attend and vote at the General Meeting or how to give a proxy or voting instructions. These directions should be followed. If you have not received such directions, it would be advisable to contact your broker, bank, or nominee (or similar) as soon as possible.

Stifel Nicolaus Europe Limited ("**Stifel**") is authorised and regulated in the United Kingdom by the FCA. Stifel is acting exclusively as sponsor for the Company and for no-one else in connection with the Acquisition and will not regard any other person (whether or not a recipient of this document) as a client in relation to the Acquisition or any other matters referred to in this document and will not be responsible for providing the protections afforded to its clients nor for giving advice in relation to the contents of this document, the Acquisition or any other matter or arrangement referred to in this document.

Apart from the responsibilities and liabilities, if any, which may be imposed upon Stifel by the FSMA or the regulatory regime established thereunder or under the regulatory regime of any jurisdiction where the exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, neither Stifel nor its affiliates accept any responsibility and disclaims any liability for the accuracy, completeness or verification, or concerning any other statement made or purported to be made by it, or on its behalf, in connection with the Company or the Acquisition in this document. No representation or warranty, express or implied, is made by Stifel or its affiliates as to the accuracy, completeness or verification of the information set forth in this document or any other statements made or purported to be made by the Company, or on the Company's behalf or by Stifel, or on behalf of Stifel in connection with the Company or the Acquisition and nothing in this document is, or shall be relied upon as, a promise or representation in this respect, whether as to the past or future. Stifel accordingly disclaims to the fullest extent permitted by applicable law all and any duty, responsibility and liability whatsoever, whether direct or indirect and whether arising in tort, contract or otherwise (save as referred to herein) which it might otherwise have in respect of this document or any such statement.

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.

This document is dated 9 May 2024.

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IMPORTANT INFORMATION

Any decision in connection with the Acquisition should be made solely on the basis of the information contained in this document (and the documents incorporated by reference). Without limitation to the foregoing, reliance should not be placed on any information in announcements released by the Company prior to the date hereof, except to the extent that such information is repeated or incorporated by reference into this document.

A letter from the Chair of the Company, which contains the recommendation of the Board to vote in favour of the Acquisition is set out in Part 1 (''*Letter from the Chair*''). A General Meeting to consider the proposals contained in this document will be held at 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 28 May 2024.

Information not contained in this document

No person has been authorised to 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 by the Company. Subject to the requirements of the FSMA, the Listing Rules, DTRs and the UK Market Abuse Regulation, 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, the Group, or the Target Assets 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.

Any information that is incorporated by reference into documents, which in turn are incorporated into this document, is not incorporated by reference into and does not form part of this document. 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 Shareholders 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 regarding the Company's or the Group's strategy, plans, objectives, goals and other future events or prospects are forward-looking statements. Shareholders 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 Shareholders 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, the Group's and/or the Enlarged 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 Part 2 (*Risk Factors)* in this document.

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 and the UK Market Abuse Regulation, none of the Company or the Sponsor undertakes 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 or otherwise by law and/or by any regulatory authority, but assumes no further obligation to publish 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, the Group's and/or the Enlarged 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

Save for the Profit Forecast, no statement in this document is intended as a profit forecast or a profit estimate for any period 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.

The announcement published by the Company on 19 March 2024 in connection with, among other things, the proposed Acquisition contained a profit forecast for the purposes of the Listing Rules for the year ending 31 December 2024 on a pro forma basis for the Target Assets. Further details of the Profit Forecast are set out Part 1 and Part 7 of this document.

Presentation of financial information

Unless otherwise indicated, unaudited summary trading results of the Target Assets for the two financial years ended 31 December 2022 and 31 December 2023 presented in this document (together, the "**Target Assets' Financial Information**") is presented in US dollars. The Target Assets' Financial Information is not audited and has not been prepared in accordance with IFRS.

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 are based on information derived from the Group's regularly maintained records and accounting and operating systems.

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**", "**USD**", "**$**" or "**US$**" 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.

Presentation of Reserves

This document presents information concerning the Target Assets reserves, which have been audited by NSAI in connection with the Acquisition. This document presents information concerning reserves using SPE PRMS as the standard for classification and reporting. All reserves information in this document is presented on the basis of SPE PRMS standards, unless otherwise indicated. All existing reserves estimates for the Target Assets are as of 1 January 2024.

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.

Typical to the industry in which the Group operates, there are a number of uncertainties inherent in estimating quantities of 2P reserves. The reserve information on the Target Assets is based on the Company's assessments of the Target Assets and its opinion as to the reasonableness of such assessments and represent only estimates. Reserve assessment is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of a number of variable factors and assumptions, many of which are beyond the Group's control, including the quality of available data and of engineering and geological interpretation and judgement and assumptions as to oil price. As a result, estimates of different reserve assessors may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to the inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of reserves estimates, the initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The significance of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Thus, Shareholders should not place undue reliance on the accuracy of the reserves information in this document in predicting actual reserves or on comparisons of similar estimates/information concerning companies established in other economic systems. In addition, except to the extent that the Group acquires additional properties containing 2P reserves or conduct successful exploration and development activities, or both, the Group's 2P reserves will decline as reserves are produced.

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

Shareholders should read the whole of this document for more information on the Company's reserves and the reserves definitions the Company uses.

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.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	David Edward Johnson (*Independent Non-executive Chair*) Robert ''Rusty'' Russell Hutson Jr. (*Chief Executive Officer*) Martin Keith Thomas (*Non-executive Vice Chair*) Sylvia Kerrigan (*Independent Non-executive Director and Senior Independent Director*) David Jackson Turner, Jr. (*Independent Non-executive Director*) Kathryn Z. Klaber (*Independent Non-executive Director*) Sandra (Sandy) Mary Stash (*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	Latham & Watkins (London) LLP 99 Bishopsgate London ECM2 3XF United Kingdom
Legal Advisers to the Sponsor	Ashurst LLP London Fruit & Wool Exchange 1 Duval Square London E1 6PW United Kingdom
Reporting Accountant	Crowe U.K. LLP 55 Ludgate Hill London EC4M 7JW United Kingdom
Competent Person	Netherland, Sewell & Associates, Inc. 2100 Ross Avenue, Suite 2200 Dallas, Texas 75201 United States

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

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 by way of an announcement issued via a RIS provider.

Announcement of the Acquisition	19 March 2024
Publication of this document (including the Notice of General Meeting) and Form of Proxy	9 May 2024
Latest time and date for receipt of Forms of Instruction / CREST electronic voting instructions for the General Meeting	1.00 p.m. (London time) / 8.00 a.m. (New York time) on 22 May 2024
Latest time and date for receipt of Forms of Proxy for the General Meeting	1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024
General Meeting	1.00 p.m. (London time) / 8.00 a.m. (New York time) on 28 May 2024
Announcement of the results of the General Meeting	28 May 2024
Expected date of Completion	within 60 days following the approval of the Resolution

Part 1
LETTER FROM THE CHAIR

Registered in England and Wales No: 09156132

Directors	**Registered Office**
David Edward Johnson	4th Floor Phoenix House
Robert "Rusty" Russell Hutson Jr.	1 Station Hill, Reading
Martin Keith Thomas	Berkshire, RG1 1NB
Sylvia Kerrigan	United Kingdom
David Jackson Turner, Jr.	
Kathryn Z. Klaber	
Sandra (Sandy) Mary Stash	

9 May 2024

Dear Shareholders,

Proposed acquisition of interests in certain assets from OCM Denali INT Holdings PT, LLC

and

Notice of General Meeting

1. Introduction

On 18 March 2024, the Company's subsidiaries, Diversified Production LLC ("**Diversified Production**") and Diversified Gas & Oil Corporation ("**DGOC**"), entered into a membership interest purchase agreement (the "**MIPA**") with OCM Denali INT Holdings PT, LLC (the "**Seller**"), a subsidiary of Oaktree Capital Management, L.P. to acquire 100% of the limited liability company interests in OCM Denali Holdings (the "**Target Assets**") pursuant to which the Group will acquire the working interests in certain assets operated by it in the Central Region (the "**Acquisition**").

Pursuant to the terms of the MIPA, the gross consideration payable by Diversified Production to the Seller in respect of the Subject Interests is $410 million (expected to be approximately $386 million net, including customary purchase price adjustments), which includes the assumption of approximately $120 million in amortising notes, net of hedges (the "**Consideration**"). A portion of the Consideration equal to approximately $88 million would be paid to the Seller under a credit arrangement as deferred cash payments, consisting of $25 million paid 6 months after Completion, $25 million paid 12 months after Completion and the remaining balance paid 18 months after Completion.

It is intended that the expected net Consideration of $386 million at Completion will be funded by the Group as follows:

- **Assumption of existing debt of the Seller:** $120 million of net outstanding amount of ABS VI, representing the Seller's portion of the jointly completed ABS VI will be assumed by the Group;
- **Deferred consideration**: $88 million to be paid to the Seller as deferred cash payments consisting of $25 million paid 6 months after Completion, $25 million paid 12 months after Completion and the remaining balance paid 18 months after Completion;
- **ABS Warehouse Facility:** $75 million from the net proceeds of the ABS Warehouse Facility ("**ABS Warehouse Facility**"); and
- **Credit Facility**: $103 million by drawing this amount on its revolving loan facility with KeyBank, National Association and certain other lenders (the "**Credit Facility**").

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

The Acquisition is of sufficient size relative to that of the Group to constitute a Class 1 transaction under the Listing Rules and is accordingly conditional upon the approval of Shareholders.

Your approval of the Acquisition is therefore being sought at a General Meeting to be held at 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 28 May 2024 at the offices of FTI Consulting, 200 Aldersgate, Aldersgate Street, London, EC1A 4HD, United Kingdom. A notice of the General Meeting setting out the Resolution to be considered at the General Meeting can be found at the end of this document. A summary of the action you are requested to take in connection with the General Meeting is set out in paragraph 10 of this letter and on the Form of Proxy that accompanies this document.

The purpose of this document is to explain the background to, and provide you with information on, the Acquisition and to issue a Notice of General Meeting to be held to consider, and if thought appropriate, pass the Resolution needed to complete the Acquisition. This document also explains why the Board considers the Acquisition and related Resolution to be in the best interests of the Company and its Shareholders taken as a whole and why the Board unanimously recommends that Shareholders vote in favour of the Resolution. Shareholders should read the whole of this document and not just rely on the summarised information set out in this letter.

2. Background to and reasons for the Acquisition

The proposed Acquisition represents a continuation of the Group's successful multi-year track record of strategic asset purchases.

As announced on 5 October 2020, the Group entered into a strategic participation agreement (the "**Strategic Partnership Agreement**") with Oaktree to jointly identify and fund future proved developed producing acquisition opportunities that the Group would identify over a three-year period.

Since then, each of the Group and Oaktree has co-invested in four material proved developed producing assets as follows:

- On 30 April 2021, the Company announced the acquisition of certain Cotton Valley upstream assets and related facilities primarily in the state of Louisiana (the "**Indigo Assets**") from Indigo Minerals LLC for a gross consideration of $135 million, which was completed on 19 May 2021 (the "**Indigo Acquisition**");
- On 5 July 2021, the Company announced the acquisition of certain Cotton Valley and Haynesville upstream assets and related facilities (the "**Tanos Assets**") in the states of Louisiana and Texas from Tanos Energy Holdings III LLC for a gross consideration of $154 million, which was completed on 18 August 2021 (the "**Tanos Acquisition**");
- On 7 October 2021, the Company announced the acquisition of certain upstream assets, field infrastructure, equipment and facilities (the "**Tapstone Assets**") within the Company's Central Region from Tapstone Energy Holdings, LLC and its related party - KL CHK SPV, LLC for a net consideration of $181 million, which was completed on 8 December 2021 (the "**Tapstone Acquisition**");
- On 26 April 2022, the Company announced the acquisition of certain East Texas upstream assets and related facilities (the "**East Texas Assets**") from a private seller for a net consideration of $50 million (the "**East Texas Acquisition**")

In accordance with the terms of the Strategic Partnership Agreement, the Group and Oaktree have each funded 50% of the net purchase price in exchange for their proportionate working interests of 51.25% to the Company and 48.75% to Oaktree for the Indigo Acquisition, the Tanos Acquisition, Tapstone Acquisition, and 52.5% and 47.5% for the East Texas Acquisition.

Under the terms of the Strategic Participation Agreement, the Group has the right of first offer to acquire Oaktree's interest when Oaktree decides to divest any assets acquired by Oaktree under the Strategic Participation Agreement. Further, the Group and Oaktree each have the right to participate in a sale by the other party with a third party upon comparable terms.

In accordance with its stated strategy, the Group proposes to acquire Oaktree's proportionate interest in each of the Indigo Assets, the Tanos Assets, the Tapstone Assets and the East Texas Assets for an estimated gross purchase price of $410 million (expected to be approximately $386 million net at Completion, including customary purchase price adjustments), which includes the assumption of approximately $120 million in amortising notes, net of hedges. In connection with the Acquisition, the Group will acquire a hedge book with a positive mark-to-market of approximately $70 million.

The proposed Acquisition is expected to be accretive and following completion of the proposed Acquisition, the Group's average working interest in the Assets will increase by approximately 100% in each of the Indigo Assets, the Tanos Assets, the Tapstone Assets and the East Texas Assets, highlighting the Company's emphasis on efficient operation of high ownership interest assets to maximise cash returns for the life of the Target Assets.

The key reasons for the proposed Acquisition are:

- The proposed Acquisition consolidates the Group's working interest in the existing operations in the Central Region by adding approximately 503 Bcfe of PDP reserves at an attractive value of approximately a PV17 of PDP reserves (PV10 value of $481 million);
- The Group will benefit from a favorable per unit cost as there are no additional general or administrative expenses expected to be incurred from acquiring the additional working interests in each of the Indigo Assets, the Tanos Assets, the Tapstone Assets and the East Texas Assets;
- The proposed Acquisition offsets natural declines as the Target Assets include wells currently operated by the Group throughout the Central Region and are expected to add production of 122 MMcfepd (80% natural gas), representing an increase of 15% as compared to the Group's previously announced average daily production for the year ended 31 December 2023;
- With an advantageous production-to-reserves ratio for the Target Assets of 11x, the Company's corporate decline rate remains unchanged at approximately 10% per year. The overall production of the Group will increase by approximately 15% increase as a result of the proposed Acquisition;
- The proposed Acquisition is expected to provide a robust cash flow for the Group with an expected pro forma Adjusted EBITDA of the Target Assets for the year ending 31 December 2024 being $126 million and an Adjusted EBITDA multiple of 3.1x;
- The location of the assets in Texas, Louisiana and Oklahoma are proximate to Gulf Cost pricing hubs that historically have experienced premium pricing as compared to the Group's Appalachia operations and the proposed Acquisition will add to the Group exposure to the favorable Gulf Coast pricing and takeaway capacity; and
- The proposed Acquisition also creates an opportunity to layer additional hedges into a stronger commodity price environment.

Further, under the terms of the MIPA, the Group will also acquire certain hedging contracts from the Seller that will provide ongoing protection despite the recent downturn in the gas market at volumes consistent with the Group's overall hedging strategy, while also maintaining strong long-term cash upside potential from the Target Assets.

3. Summary information on the Target Assets

The Target Assets comprise the Seller's current proportionate working interest in each of the Indigo Assets, the Tanos Assets, the Tapstone Assets and the East Texas Assets.

The Target Assets include wells currently operated by the Group throughout the Central Region and are expected to add production of 122 MMcfepd (80% natural gas), representing an increase of 15% as compared to the Group's previously announced average daily production for the year ended 31 December 2023. With an advantageous production-to-reserves ratio for the Target Assets of 11x, the Company's corporate decline rate is expected to remains unchanged at approximately 10% per year.

The unaudited historical production of natural gas, oil and NGL from the Target Assets for the year ended 31 December 2023 are as follows:

Net volumes	
Natural gas (MMcf)	40,388,491
Oil (Mbbl)	689,737
NGL (Mbbl)	959,726
Equivalents	
MMcfe	50,285,268
Mboe	8,380,878

Equivalents per day	
MMcfed	137,768
Mboed	22,961

The Target Assets do not constitute a separate legal entity and therefore, there are no previous standalone financial statements available for the Target Assets. It is not feasible to prepare audited historical financial information for the Target Assets for the last three years (the "**HFI Period**") under the Group's accounting policies. The Seller does not prepare its financial statements in accordance with IFRS, the accounting standards adopted by the Group for its financial statements. The preparation of the audited financial information on the Target Assets to comply with IFRS is not possible in retrospect as all the information required for the HFI Period is not available to the Seller.

Further, for the part of the HFI Period prior to the acquisition of the Target Assets by the Seller, the Target Assets were held by third party entities. Such third parties entities held the Target Assets together with other assets, including producing wells, undeveloped land, gas gathering pipelines, compression & treating facilities, corporate assets and exploration assets, rather than on a stand-alone basis. No separate financial statements exist in relation to the Target Assets in relation to this period. Neither the Seller nor the Company has access to such third parties so it is not possible to produce such financial statements even if the underlying information existed.

Since the acquisition of the Target Assets by the Seller, the Seller has also not held the Target Assets in one entity on a stand-alone basis separately from its other assets. The Seller has not maintained separate accounting records or prepared separate audited financial statements for the Target Assets. It is not possible for the Seller to prepare carve-out financial statements for the Target Assets on a retrospective basis as all the financial information available to the Seller is only available on a consolidated basis for the Target Assets together with all its other assets. The Seller is unable to separate such information for the Target Assets on a retrospective basis. For example, tax payable by the Seller is not recorded for the Target Assets only but on a consolidated basis for the Seller, which includes taxes on other assets owned by the Seller. Similarly, the Seller does not hold hedges for the Target Assets on a standalone basis but on a consolidated basis for all its assets. Therefore, it is not possible to calculate the taxes for, or the impact of hedges on, the Target Assets separately in retrospect in order to prepare the audited financial information for the Target Assets since the acquisition of the Target Assets by the Seller.

The Directors believe that, even if the audited financial information on the Target Assets were available or prepared, they would be of limited relevant to the Shareholders in making a properly informed decision of the impact of the proposed Acquisition on the Company as the Target Asset's value has not been determined, to any significant degree, by past financial performance as reported in financial information, but principally on the basis of their reserves value and net asset value. The reserves value of the Acquisition Assets is based almost entirely on a production profile. The unaudited Target Assets' Financial Information is as set out in Part 4 of this document.

The Directors have relied primarily on data they have as operator of the Target Assets as well as the CPR on the Target Assets, included in Part 5 of this document, in their assessment of the value of the Target Assets. The Directors believe that the CPR on the Target Assets, along with the other information on the Target Assets as set out in this document provides shareholders with the requisite information to make a properly informed decision in their assessment of the relative merits of the proposed Acquisition and whether they should vote in favour of the proposed Acquisition.

4. Principal terms of the Acquisition

On 18 March 2024, Company's subsidiaries, Diversified Production LLC and Diversified Gas & Oil Corporation, entered into a membership interest purchase agreement 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.

Pursuant to the terms of the MIPA, the gross consideration payable by Diversified Production to the Seller in respect of the Subject Interests is $410 million (expected to be approximately $386 million net at Completion, including customary purchase price adjustments), which includes the assumption of approximately $120 million in amortising notes, net of hedges (the "**Consideration**"). A portion of the Consideration equal to approximately $90 million would be paid to the Seller under a credit arrangement as deferred cash payments, consisting of $25 million paid 6 months after Completion, $25 million paid 12 months after Completion and the remaining balance paid 18 months after Completion. Deferred cash payments of approximately $90 million to the Seller will be paid over an 18-month term with an 8% annual interest rate.

Completion of the Acquisition pursuant to the MIPA is also subject to certain customary conditions, including the shareholders of the Company having approved the transactions contemplated by the MIPA in accordance with the requirements of the Listing Rules.

The MIPA may be terminated by:

(a) the mutual written consent of Diversified Production and the Seller,

(b) by either party, if any applicable law or governmental order is in effect that makes illegal or prevents the Completion,

(c) by either party, if the Completion has not occurred by 29 July 2024,

(d) by either party, if the other party materially breaches the MIPA, which causes the non-breaching party's Completion conditions related to warranties or performance obligations to not be satisfied, subject to a customary cure period, or

(e) by either party, if such party has satisfied its Completion conditions and is ready, willing and able to close, but the other party fails to complete the closing.

If Seller terminates the MIPA due to a breach by Diversified Production of the MIPA that causes any of the Completion conditions to not be satisfied or due to failure to satisfy the Class 1 condition, Diversified Production would be required to pay to the Seller a break fee equal to \$5.5 million. If Diversified Production terminates the MIPA due to a breach by the Seller of the MIPA that causes any of the Completion conditions to not be satisfied, Diversified Production would be entitled to seek damages from the Seller. In all other circumstances, if the Acquisition is not completed, the parties would not be liable for any additional payments in connection with the Acquisition. If all Completion conditions are satisfied and either party refuses to close the Acquisition, then the other party has the ability to specifically enforce the terms of the MIPA to force Completion (subject to satisfaction of the Class 1 condition).

Please see further details of the principal terms of the Acquisition as set out in Part 3 ("*Principal Terms of the Acquisition*").

5. Summary of the proposed Consideration

It is intended that the expected net Consideration of \$386 million payable on Completion will be funded by the Group as follows:

- **Assumption of existing debt of the Seller:** \$120 million of net outstanding amount of ABS VI, representing the Seller's portion of the jointly completed ABS VI will be assumed by the Group;
- **Deferred consideration**: \$88 million to be paid to the Seller as deferred cash payments consisting of \$25 million paid 6 months after Completion, \$25 million paid 12 months after Completion and the remaining balance paid 18 months after Completion;
- **ABS Warehouse Facility:** \$75 million from the net proceeds of the ABS Warehouse Facility; and
- **Credit Facility**: \$103 million by drawing this amount on its revolving loan facility with KeyBank, National Association and certain other lenders.

For further details of the Credit Facility, ABS VI and the ABS Warehouse Facility, please see sections 8.1(l) and 8.1(n) in Part 7 ("*Additional Information*") of this document. For details of the refinancing of the Credit Facility, please see section 6 of Part 1 below.

6. Current trading and future prospects, including trend information

The Group's unique business model was well positioned to successfully navigate the headwinds of a volatile natural gas market in recent times driven by ever-changing supply and demand fundamentals.

For the year ended 31 December 2023, the Group's total net daily production was 137 Mboepd, representing an increase of 1 per cent. from the Group's 2022 average production rate of 135 Mboepd and demonstrating the Group's success at meeting growing energy demand. For the three months ended 31 March 2024, the total net daily production was 121 Mboepd. Adjusted for the impact of the divestment, production declines remain an industry-leading approximately 10 per cent, per year on reported production.

As part of its emphasis on navigating a path for 2024 and beyond with its 'Focus Five' principles, the Group recognises the value created through liquidity-enhancing transactions, prioritising transactions that unlock hidden asset value and reduce debt-serving costs. Similar to its 'Value Enhancing Asset Sale' as announced on 2 January 2024, there continues to be a robust market for the equity interest of a Special Purpose Vehicle ("**SPV**") containing ABS assets, and the Group intends to continue to capitalise on the current market dynamics to increase liquidity on its Credit Facility in 2024. Additionally, given the advantages of ABS debt capitalisation and the amortisation structure within those instruments, the Group continues to explore opportunities to refinance its existing notes to create enhanced liquidity on its Credit Facility. This enhanced liquidity will provide the Group with financial flexibility for use in all areas of its previously announced capital allocation framework, which includes debt reduction, dividends, share repurchases and growth.

The Group was built to ensure resilience in volatile economic environments, and due to the Group's low-cost operations and approach to risk mitigation through an opportunistic hedging strategy, the Group remains well-placed to consider new opportunities that arise as a result of the price volatility in the market backdrop. Operating efficiencies will remain one of the key priorities for the Group in the near term as it seeks to protect and enhance margins across the business.

The Group continues to execute its strategy of production growth through accretive acquisitions and driving down unit operating costs through the integration of its acquisitions and the use of Smarter Asset Management to offset natural production declines. The Group's Smarter Asset Management programme continues to yield positive results as the Group is succeeding in minimising production declines on its assets. Inclusive of the Group's recently completed acquisitions in the Central Region, the Group estimates its consolidated corporate decline will be an industry-leading ~10 per cent. per year.

For the year ended 31 December 2023, the Group's Adjusted EBITDA (hedged) was approximately $543 million, compared to $503 million for the year ended 31 December 2022.

The Group achieved total cash margins of nearly 52 per cent for the year ended 31 December 2023 primarily driven by slightly higher production and improvements in midstream operating expense and production tax expenses from the Group's assets.

For the three months ended 31 March 2024, the Group's Adjusted EBITDA was $102 million and achieved total cash margins of 48 per cent., reflective of the lower commodity price environment during that period compared to the year ended 31 December 2023 and offset by decreases in certain per unit costs.

The Group remains well-positioned to continue its rapid growth, with a robust business underpinned by a diverse and low-cost asset base, strong cash flow, healthy balance sheet, proven business model and an entrepreneurial leadership team whose primary considerations are value creation, operational excellence and environmental stewardship.

7. Profit forecast for the Target Assets

On 19 March 2024, the Company announced, among other things, the proposed Acquisition in accordance with the requirements of the Listing Rules. In that announcement, the Company made the following statements in relation to the financial targets for the Target Assets for the 12 month period ending 31 December 2024:

- "*Provides robust cash flow with 2024 Adjusted EBITDA of $126 million*"

The above statement constitutes a profit forecast for the purpose of the Listing Rules (the "**Profit Forecast**"). The Profit Forecast relates to the pro forma 12-month period ending 31 December 2024 and relates to Adjusted EBITDA.

The Directors have considered and confirm that the Profit Forecast remains correct as at the date of this document. Further information in relation to the Profit Forecast is provided in Part 7 (*Additional Information*) of this document.

8. Financial effects of the Acquisition

On an unaudited pro forma basis and assuming that the Acquisition had taken place on 31 December 2023, the Group would have had net assets of $548.3 million, compared with net assets of $598.4 million reported as at 31 December 2023. Please refer to Part 6 ("*Unaudited Pro Forma Financial Information*") which contains an unaudited Pro Forma Statement of Financial Position and an unaudited Statement of Comprehensive Income, prepared to illustrate the effect on the assets, liabilities and equity of the Group as at 31 December 2023 as if the proposed Acquisition had taken place on that date with respect to the Pro Forma Statement of Financial Position, and on the results of the year then ended as if the proposed Acquisition had taken place on 1 January 2023 with respect to the Statement of Comprehensive Income.

9. Risk factors

You should consider fully the risk factors associated with the Acquisition. Your attention is drawn to Part 2 (*Risk Factors*) set out in this document.

10. General Meeting and actions to be taken

A notice convening the General Meeting to be held at the offices of FTI Consulting, 200 Aldersgate, Aldersgate Street, London, EC1A 4HD, United Kingdom, on 28 May 2024 at 1.00 p.m. (London time) / 8.00 a.m. (New York time) is set out at the end of this document. The purpose of the General Meeting is to consider and, if thought fit, pass the Resolution.

Shareholders will find enclosed a Form of Proxy for use at the General Meeting. Depositary Interest Holders will need to complete a Form of Instruction or submit their voting instruction via the CREST voting system as set out in the 'Notes to the Notice of General Meeting' section. To be valid for use at the General Meeting, the Form of Proxy must be completed and returned, in accordance with the instructions printed thereon, to Broadridge Financial Solutions, Inc. at Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717 as soon as possible and, in any event, to arrive by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024.

The completion and return of a Form of Proxy will not preclude Shareholders from attending and voting in person at the General Meeting should they subsequently wish to do so. The Form of Instruction should be returned to the Depositary, Computershare Investor Services PLC, the Pavilions, Bridgwater Road, Bristol, BS99 6ZY, United Kingdom by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 22 May 2024. Depositary Interest Holders wishing to attend the meeting in person should refer to the 'Notes to the Notice of General Meeting' section for instructions on how to attend.

If you hold your interest through a broker, bank, or nominee (or similar), you should normally receive directions from such broker, bank, or nominee (or similar) on how to (electronically or in person) attend and vote at the General Meeting or how to give a proxy or voting instructions. These directions should be followed. If you have not received such directions, it would be advisable to contact your broker, bank, or nominee (or similar) as soon as possible.

11. Further information

You should read the whole of this document (including the information incorporated into this document by reference) and not just rely on the information contained in this letter.

12. Financial advice

If you are in any doubt as to the action you should take, you are recommended to seek your own financial advice immediately from an independent financial adviser, who is authorised under the FSMA if you are in the United Kingdom, or from another appropriately authorised independent financial adviser if you are in a territory outside the United Kingdom.

13. Recommendation

The Board considers the Acquisition and the related Resolution to be in the best interests of the Company and its Shareholders as a whole.

The Directors intend to vote in favour of the Resolution to be proposed at the General Meeting in respect of their own beneficial holdings of Ordinary Shares amounting to 1,375,193 Ordinary Shares and approximately 2.89 per cent. of the total number of votes available to be cast at the General Meeting. Accordingly, the Board unanimously recommends that you vote in favour of the Resolution to be proposed at the General Meeting.

Yours faithfully

David E. Johnson

Chair

Part 2
RISK FACTORS

The Acquisition is subject to a number of risks. Accordingly, prior to making any decision to vote in favour of the Resolution, Shareholders should carefully consider all the information contained in this document, including, in particular, the specific risks and uncertainties described below. The risks and uncertainties set out below are those which the Directors believe are the material risks relating to the Acquisition, material new risks to the Group as a result of the Acquisition or existing material risks to the Group which will be impacted by the Acquisition. If any, or a combination of, these risks actually materialise, the business, results of operations, financial condition or prospects of the Enlarged Group could be materially and adversely affected. The risks and uncertainties described below are not intended to be exhaustive and are not the only ones that face the Group.

The information given is as at the date of this document and, except as required by the FCA, the London Stock Exchange, the Listing Rules, UK Market Abuse Regulations and/or any regulatory requirements or applicable law, will not be updated. Additional risks and uncertainties not currently known to the Directors or that they currently deem immaterial, may also have an adverse effect on the business, financial condition, results of operations and prospects of the Group. If this occurs, the price of the Ordinary Shares may decline and Shareholders could lose all or part of their investment.

RISKS RELATING TO THE ACQUISITION AND THE ENLARGED GROUP

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 realise the perceived benefits of the Acquisition.

The completion of the Acquisition is subject to the satisfaction (or waiver, if applicable) of certain conditions, including each of the Group and the Seller having materially performed and complied with their respective obligations under the MIPA as to which performance or compliance is required prior to Completion. The Seller may, at its own discretion, choose to waive certain obligations of the Group that fall to be performed prior to Completion, but may choose not to waive any or all of such conditions.

Further, the Seller may elect to terminate the MIPA if the shareholders of the Company have not approved the transactions contemplated by the MIPA or any part of the transactions by 29 July 2024 (or such other date as the parties may agree in writing). In addition, the MIPA may be terminated by either the Group or the Seller (i) if the Completion has not occurred on or before 29 July 2024 (the "**Long Stop Date**"), or (iii) by mutual written consent of both parties.

There can be no assurance that the outstanding conditions will be satisfied, or that Completion will be achieved by the Long Stop Date or such later date as the parties may agree in writing, or at all and certain of the conditions are not capable of waiver. 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 the Seller expect. Any delay in completing the proposed Acquisition may adversely affect the benefits that the Company expects to achieve if the Acquisition is completed within the expected timeframe.

A break fee may be payable by the Group if the proposed Acquisition does not proceed.

In the event that the MIPA is terminated due to the Company having failed to procure approval from its Shareholders for the proposed Acquisition in accordance with the terms of the MIPA, a break fee of $5,500,000 will be payable by the Group to the Seller.

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

The reserves data for the Target Assets contained in this document has been audited by NSAI unless stated otherwise. The standards utilized to prepare the reserves information that has been extracted in this document may be different from the standards of reporting adopted in other jurisdictions. The data found in the reserves information set forth in this document may not be directly comparable to similar information 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 our 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 Company'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 portfolio of the Target Assets have been productive for a much longer time. As a result, there is a risk that estimates of the 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 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 Target Assets' natural gas and oil reserves prove to be incorrect or if the actual reserves available to the Group are otherwise less than the current estimates or of lesser quality than expected, the Enlarged 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 business, results of operations, financial condition, cash flows or prospects of the Enlarged Group.

The PV-10 of the Target Assets will not necessarily be the same as the current market value of the Target Assets' estimated natural gas, NGL and oil reserves.

The present value of future net cash flows from the reserves of the Target Assets is the current market value of the estimated natural gas, NGL and oil reserves of the Target Assets. The PV-10 of the Target Assets is the present value of future cash flows from the reserves of the Target Assets given a discount rate of 10 per cent. Actual future net cash flows from the Target Assets natural gas and oil properties will be affected by factors such as:

- actual prices received for natural gas, NGL and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- transportation and processing;
- access to transportation and processing systems and related tariffs and costs;
- actual costs for decommissioning obligations; and
- changes in governmental regulations or taxation.

The timing of both the production and the incurrence of expenses in connection with the development and production of the natural gas and oil properties of the Target Assets 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 used 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 Target Assets 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.

Part 3
PRINCIPAL TERMS OF THE ACQUISITION

1. Background

On 18 March, 2024 the Company's subsidiaries, Diversified Production LLC ("**Diversified Production**") and Diversified Gas & Oil Corporation ("**DGOC**"), entered into a membership interest purchase agreement (the "**MIPA**") with OCM Denali INT Holdings PT, LLC (the "**Seller**"), a subsidiary of Oaktree Capital Management, L.P. to acquire 100% of the limited liability company interests in OCM Denali Holdings, LLC ("**OCM**" and the limited liability company interests, the "**Subject Interests**") from Seller.

2. Consideration

Pursuant to the terms of the MIPA, the gross consideration payable by Diversified Production to the Seller in respect of the Subject Interests is $410 million (expected to be approximately $386 million net at Completion, including customary purchase price adjustments), which includes the assumption of approximately $120 million in amortising notes, net of hedges (the "**Consideration**"). A portion of the Consideration equal to approximately $90 million would be paid to the Seller under a credit arrangement as deferred cash payments, consisting of $25 million paid 6 months after Completion, $25 million paid 12 months after Completion and the remaining balance paid 18 months after Completion. Deferred cash payments of approximately $90 million to the Seller will be paid over an 18-month term with an 8% annual interest rate.

The Consideration is subject to customary adjustments, including in respect of:

(a) proceeds not distributed to Seller and attributable to the ownership of OCM's oil and gas properties prior to 1 November 2023 (the "**Effective Time**") (net of certain costs and expenses);

(b) certain costs borne by Seller associated with the settlement of hedges between 1 January 2024 and Completion or the novation or termination of hedges at Completion;

(c) certain distributions or payments of money from OCM to Seller or other parties between the Effective Time and Completion, including for unpaid property expenses attributable to the period prior to the Effective Time;

(d) certain payments to Seller or OCM associated with the settlement of hedges between 1 January 2024 (for the Seller) and 1 November 2023 (for OCM) and Completion or the termination of hedges at Completion;

(e) OCM's share of suspense balances associated with its oil and gas properties; and

(f) transaction expenses incurred by OCM and not paid by Seller as of Completion.

3. Conditions

Completion of the Acquisition pursuant to the MIPA ("**Completion**") is subject to certain customary conditions, including:

(a) the shareholders of the Company having approved the transactions contemplated by the MIPA in accordance with the requirements of the Listing Rules (the "**Class 1 condition**");

(b) there not being any law in effect that makes Completion illegal or any governmental order in effect preventing Completion;

(c) fundamental warranties given by Seller remaining true and correct in all respects, and all other warranties given by Seller being true and correct in all respects on and as of the Completion, except to the extent the failure of such warranties to be so true and correct has not had, and would not reasonably be expected to have, a material adverse effect;

(d) each of the warranties given by Diversified Production being true and correct in all respects on and as of the Completion; and

(e) each party having materially performed and complied with their respective obligations in the MIPA as to which performance or compliance is required prior to Completion.

4. Warranties and indemnities

The MIPA contains customary warranties for similar transactions in which the Company is familiar with the underlying oil and gas properties. The Seller has given warranties in relation to, among other things, capacity, certain corporate matters, bankruptcy, litigation, existing contractual arrangements, capitalisation and ownership of the Subject Interests, affiliate arrangements, no undisclosed liabilities, indebtedness and absence of changes since the Effective Time. Diversified Production has given limited warranties in relation to, among other things, capacity, certain corporate matters, bankruptcy, and sufficiency of funds to complete the Acquisition.

Customary indemnities have also been given by each of the Seller and Diversified Production in respect of their respective warranties and obligations under the MIPA and any assumed obligations in relation to the Subject Interests. The Seller's obligation to indemnify Diversified Production is subject to certain customary limitations, including claim thresholds, deductibles, caps and survival periods. Diversified Production and DGOC are jointly and severally liable for all obligations under the MIPA.

5. Conduct prior to Completion

Between the signing of the MIPA and Completion, subject to certain exceptions, the Seller has undertaken to (among other things):

(a) conduct its business in the ordinary course and in accordance with applicable law; and

(b) not undertake certain actions in relation to OCM and the Subject Interests unless consented to in writing by Diversified Production.

6. Title and Environmental Matters

Given Diversified Production's current co-ownership in and operation of the oil and gas properties held by OCM, the MIPA does not contain provisions related to title or environmental matters, other than a customary special warranty of title from the Seller.

7. Termination

The MIPA may be terminated by:

(a) the mutual written consent of Diversified Production and the Seller,

(b) by either party if any applicable law or governmental order is in effect that makes illegal or prevents the Completion,

(c) by either party, if the Completion has not occurred by 29 July 2024,

(d) by either party, if the other party materially breaches the MIPA, which causes such party's Completion conditions related to warranties or performance obligations to not be satisfied, subject to a customary cure period, or

(e) by either party, if such party has satisfied its Completion conditions and is ready, willing and able to close, but the other party fails to complete the closing.

If Seller terminates the MIPA due to a breach by Diversified Production of the MIPA that causes any of the Completion conditions to not be satisfied or due to failure to satisfy the Class 1 condition, Diversified Production would be required to pay to the Seller a break fee equal to $5.5 million. If Diversified Production terminates the MIPA due to a breach by the Seller of the MIPA that causes any of the Completion conditions to not be satisfied, Diversified Production would be entitled to seek damages from the Seller. In all other circumstances, if the Acquisition is not completed, the parties would not be liable for any additional payments in connection with the Acquisition. If all Completion conditions are satisfied and either party refuses to close the Acquisition, then the other party has the ability to specifically enforce the terms of the MIPA to force Completion (subject to satisfaction of the Class 1 condition).

8. Governing Law

The MIPA is governed by the laws of the state of Delaware, United States.

Part 4
UNAUDITED HISTORICAL FINANCIAL INFORMATION RELATING TO THE TARGET ASSETS

The unaudited Target Assets' Financial Information presented in this document has been compiled on the following basis:

Trading results

Basis of preparation

The revenue and operating expenditure presented down to gross profit has been prepared on a cash basis for the two years ended 31 December 2022 and 31 December 2023. Gross profit therefore represents the aggregate total cash inflows and outflows of the Target Assets during each reporting period.

Below gross profit, the actual gains on financial instruments and finance costs for each of the years ended 31 December 2022 and 31 December 2023 are extracted, without adjustment, from the Seller's unaudited financial information for each of those periods.

The imputed tax charges for each of the years ended 31 December 2022 and 31 December 2023 has been calculated using the Group's underlying tax rates as stated in its audited financial statements for each of the years in question.

Revenue

Revenue relates to the sale of natural gas, oil and NGL to which the Seller was entitled due to its participation in the Target Assets. Revenue is recognised when production occurs and is a function of the volume of natural gas, the quantity of barrels of oil produced and the volume of NGL and the sales prices achieved per MMbtu, bbl and bbl, respectively.

Lease operating expenditure, district-level expenditure, transportation and production taxes

Lease operating expenditure, district-level expenditure, transportation and production taxes are expenditures incurred by the Group in its role of operator of the Target Assets. Such costs are recharged to the Seller on the basis of its working interest percentage in the Target Assets. The recharges are reported to the Seller via *"lease operating statements"* prepared by the Group, which categorise expenditures as follows:

(a) lease operating expenditure;

(b) district-level expenses;

(c) transportation; and

(d) production taxes.

Gain on derivative financial instruments

The unaudited gain on derivative financial information for each of the years ended 31 December 2022 and 31 December 2023 has been extracted from the Target Asset's unaudited management information prepared by the Company in accordance with its role as operator of the Target Assets. The unaudited gain in each year represents the realised gains and losses associated with the hedging arrangements of the Target Assets, specifically in relation to the ABS VI assets.

Adjusted EBITDA

Adjusted EBITDA represents the unaudited gross profit of the Target Assets, plus their share of realised gains or losses on associated derivative financial instruments during each of the two reporting periods, on an unaudited basis.

Finance costs

The stated finance costs for each of the years ended 31 December 2022 and 31 December 2023 relate to interest charges on the ABS VI notes.

Imputed tax charges

The lease operating statements provided to the Seller for the years ended 31 December 2022 and 31 December 2023 report gross profit for each year, respectively. The Company has imputed tax charges on the stated gross profit for each year using the Group's effective tax rates of 22.4% and 24.1% for the years ended 31 December 2022 and 31 December 2023, respectively.

Unaudited summary trading results

The unaudited summary trading results of the Target Assets for the two years ended 31 December 2022 and 31 December 2023 are as follows:

	(Unaudited) Year ended 31 December 2022	*(Unaudited)* Year ended 31 December 2023
	$'000	$'000
Revenue (Unhedged)	**348,803**	**177,430**
Lease operating expenditure	(38,791)	(41,459)
District-level expenses	(15,256)	(21,023)
Transportation	(11,154)	(9,478)
Production taxes	(19,837)	(16,437)
Gross profit	**263,765**	**89,033**
Gain on derivative financial instruments	2,353	24,829
Adjusted EBITDA	**266,118**	**113,862**
Finance costs	(2,618)	(12,859)
Profit before tax	**263,500**	**101,003**
Tax charge *(imputed at 22.4% and 24.1%, respectively)*	(59,024)	(24,342)
Profit after tax	**204,476**	**76,661**

Statement of Financial Position

The Acquisition of the Target Assets will result in the Company acquiring certain assets and liabilities of the Seller, together with adjustments to certain of the Group's current liabilities, reflected as *"customary purchase price adjustments"* on Acquisition.

Basis of preparation

The assets and liabilities in question are set out below, as extracted from the Seller's unaudited financial information as at 31 December 2023 and the Company's audited financial statements for the year ended 31 December 2023, as available on the Company's website at www.ir.div.energy/financial-information:

As at 31 December 2023	Source	*Audited / unaudited*	$'000	$'000
Purchase price of the Target Assets	MIPA			**369,848**
Derivative financial instruments *(current assets)*	Seller's financial information	*Unaudited*		40,152
Total purchase price				**410,000**
Post-effective date cash *(current liabilities)*	Company's financial statements	*Audited*	(16,000)	
Oaktree allocation of suspense *(current liabilities)*	Company's financial statements	*Audited*	(7,664)	
Customary purchase price adjustments				*(23,664)*
Purchase price *(net of customary purchase price adjustments)*				**386,336**
Amortising notes *(non-current liabilities)*	Seller's financial information	*Unaudited*	(124,510)	
Amortising notes *(current liabilities)*	Seller's financial information	*Unaudited*	(33,604)	
Borrowings acquired			*(158,114)*	
Restricted cash acquired *(current assets)*	Seller's financial information	*Unaudited*	6,114	
Derivative financial instruments *(current assets)*	Seller's financial information	*Unaudited*	32,000	
Amortising notes acquired, net of hedges				*(120,000)*

As at 31 December 2023	Source	*Audited / unaudited*	$'000	$'000
Net Consideration payable				**266,336**
Satisfied by:				
Cash on Acquisition				178,168
Deferred Consideration *(6 Months)*				25,000
Deferred Consideration *(12 Months)*				25,000
Deferred Consideration *(18 Months)*				38,168
				266,336

ESTIMATES

of

RESERVES AND FUTURE REVENUE

to the

DIVERSIFIED ENERGY COMPANY PLC ACQUISITION INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in the

UNITED STATES

as of

JANUARY 1, 2024

COMPETENT PERSON'S REPORT

BASED ON PRICE AND COST PARAMETERS

specified by

DIVERSIFIED ENERGY COMPANY PLC

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

May 9, 2024

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 developed reserves and future revenue, as of January 1, 2024, to the Diversified Energy Company PLC (DEC) Acquisition interest in certain oil and gas properties located in the Louisiana-Oklahoma-Texas Area of the United States. It is our understanding that DEC plans to purchase the Oaktree Capital Management, L.P. (Oaktree) interest in these properties and that the properties evaluated in this report will be included within DEC's Central Division. DEC currently owns an interest in approximately 99.8 percent of the properties evaluated in this report. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by DEC, as discussed in subsequent paragraphs of this letter. These parameters provide for the real growth of gas prices. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates in this report have been prepared in accordance with the Listing Rules published by the Financial Conduct Authority (FCA) and the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA (Primary Market TN 619.1), and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). Definitions are presented immediately following this letter. Following the definitions are certificates of qualification for the 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 Class 1 transaction proposed to be undertaken by DEC in accordance with the Listing Rules. 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 DEC Acquisition interest in these properties, as of January 1, 2024, to be:

	Net Reserves				Future Net Revenue (M$)	
Category	**Oil (MBBL)**	**NGL (MBBL)**	**Gas (MMCF)**	**Oil Equivalent (MBOE)**	**Total**	**Present Worth at 10%**
Proved Developed	5,613.7	9,210.8	413,701.4	83,774.7	819,325.3	481,028.3

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. Oil equivalent volumes shown in this report are expressed in thousands of barrels of oil equivalent (MBOE), determined using the ratio of 6 MCF of gas to 1 barrel of oil.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Proved developed reserves include proved developed producing and proved developed shut-in wells only. Our study indicates that as of January 1, 2024, there are no other proved developed non-producing or proved undeveloped reserves for these properties. No study was made to determine whether probable or possible reserves might be established for these properties. 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.

As shown in the Table of Contents, this report includes a summary projection of reserves and revenue, a technical discussion, and pertinent figures and exhibits.

Gross revenue shown in this report is the interest owner's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for the interest owner's share of production taxes, ad valorem taxes, 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 oil, NGL, and gas price parameters specified by DEC. Oil and NGL prices are based on December 29, 2023, NYMEX West Texas Intermediate prices and are adjusted for quality, transportation fees, and market differentials; for certain properties, NGL prices are negative after adjustments. Gas prices are based on December 29, 2023, NYMEX Henry Hub prices and are adjusted for energy content, transportation fees, and market differentials. The December 29, 2023, NYMEX price market forecasts do not include a price for January 2024. Oil and NGL prices for January 2024 are based on the December 19, 2023, last trading price for January of $73.44 per barrel. The gas price for January 2024 is based on the December 26, 2023, last trading day price for January of $2.619 per MMBTU. All monthly prices are averaged to determine the yearly price used in this report. As requested, although there are price hedge contracts in place for certain properties, no adjustments have been made to our estimates of future revenue to account for such contracts. All prices, before adjustments, are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2024	71.68	2.670
12-31-2025	68.32	3.491
12-31-2026	65.37	3.824
12-31-2027	63.32	3.854
12-31-2028	62.02	3.798
12-31-2029	61.28	3.704
12-31-2030	60.93	3.645
12-31-2031	60.81	3.598
12-31-2032	60.73	3.590
12-31-2033	60.38	3.645
12-31-2034	60.19	3.733
12-31-2035	60.19	3.891
Thereafter	60.19	3.997

Operating costs used in this report are based on operating expense records of DEC. For the nonoperated properties, 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. As requested, operating costs for the operated properties include only direct lease- and field-level costs. Operating costs have been divided into per-well costs and per-unit-of-production costs. For all properties, headquarters general and administrative overhead expenses are not included. As requested, this report includes additional operating expenses for the effects of all applicable firm transportation contracts. It is our understanding that DEC is supplying all committed volumes for these contracts. As requested, operating costs are not escalated for inflation.

Abandonment costs used in this report are DEC'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.

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. We have not investigated possible environmental liability related to the properties; 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 DEC Acquisition 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 the interest owner receiving its net revenue interest share of estimated future gross production. In addition, no consideration has been given to any potential future gas curtailment activities or changes in market conditions.

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 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, 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., P.E.
Chairman and Chief Executive Officer

By: ______________________________
Robert C. Barg, P.E. 71658
Senior Vice President

Date Signed: May 9, 2024

By: ______________________________
William J. Knights, P.G. 1532
Vice President

Date Signed: May 9, 2024

RCB:DCC

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.

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

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.

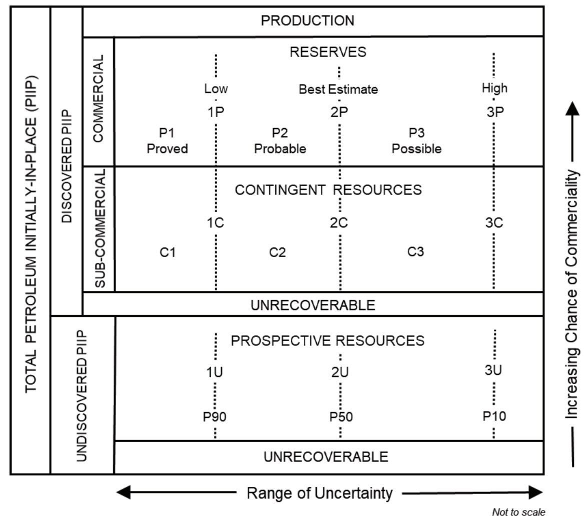

Figure 1.1—Resources classification framework

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.

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.

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).

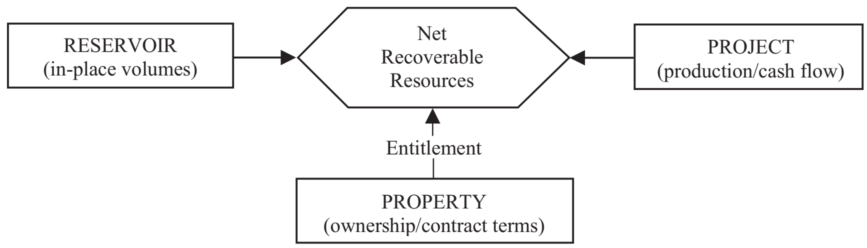

Figure 1.2—Resources evaluation

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).

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).

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
Excerpted from the 2018 Petroleum Resources Management System(PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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.

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Class/Sub-Class	Definition	Guidelines
		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.
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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	Definition	Guidelines
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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	Definition	Guidelines
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

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Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Category	Definition	Guidelines
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.
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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Category	Definition	Guidelines
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, Robert C. Barg, Licensed Professional Engineer, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, 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, 2024.

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 Purdue University and graduated in 1983 with a Bachelor of Science Degree in Mechanical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 38 years of experience in petroleum engineering studies and evaluations.

By: ___________________________________

Robert C. Barg, P.E.
Senior Vice President
Texas License No. 71658

May 9, 2024
Dallas, Texas

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, William J. Knights, Licensed Professional Geoscientist, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, 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, 2024.

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 graduated in 1981 with a Bachelor of Science Degree in Geology and in 1984 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 40 years of experience in petroleum engineering studies and evaluations.

By: ______________________________

William J. Knights, P.G.
Vice President
Texas License No. 1532

May 9, 2024
Dallas, Texas

GLOSSARY OF TERMS

$	United States dollars
%	percent
Abandonment	When a wellbore is no longer useful for production or injection, it is abandoned.
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.
b-factor	hyperbolic b-factor
Barrel (BBL)	A unit of measurement commonly used in quoting volumes of liquid hydrocarbons; 1 barrel is equivalent to 42 United States gallons.
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.
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.
Conventional	All other wells that are not unconventional.
CPR	Competent Person's Report
DCA	decline curve analysis
DEC	Diversified Energy Company PLC
DEM	Diversified Energy Marketing LLC
DP	Diversified Production LLC
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
Firm transportation contract	A contract between a transporter and a producer for transporting hydrocarbons.
Formation	A body of rock that is sufficiently distinctive and continuous that it can be mapped.
ft	feet
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 reserves	100 percent of oil and gas reserves
Gross wells	Total wells in which an interest is owned.
Hedge contract	Any option entered into for the purpose of reducing the exposure to fluctuations in the price of hydrocarbons.

Horizontal well	A type of drilling technique where an oil or gas well 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.
Lease operating expenses	The direct operating costs for a specific producing property.
M$	thousands of United States dollars
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
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.
Oaktree	Oaktree Capital Management, L.P.
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.
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 which analysis of geoscience and engineering data indicate are less likely to be recovered than probable reserves.
Present value	The value in the present of a sum of money, in contrast to some future value it will have when discounted at a specific rate.
Primary Market TN 619.1	The FCA Primary Market Technical Note 619.1 (May 2022) - Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers.
PRMS	2018 Petroleum Resources Management System
Probable reserves	Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.
Proved developed	Proved developed producing and proved developed shut-in.
Proved reserves	Those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from future wells.
Recoverable volumes	Hydrocarbons that can be extracted from a petroleum reservoir.

Reserves	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.
S&P	Standard & Poors
Sandstone	A sedimentary rock composed mainly of sand-size mineral or rock grains and often composed largely of grains of quartz.
SCOOP	South Central Oklahoma Oil Province
Sediment	Generally, waterborne debris that settles out of suspension.
Sedimentary rock	A type of rock formed by aggregation of sediments.
Shale volume	The fraction or percentage of shale contained in a rock.
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
STACK	Sooner Trend Anadarko Canadian Kingfisher
Stratigraphy	The study of the history, composition, relative ages, and distribution of strata, and the interpretation of strata to elucidate Earth history.
TCF	trillions of cubic feet
Tetco	Texas Eastern Transmission
True vertical depth (TVD)	The direct distance from a point in a well to the surface.
Unconventional	Wells producing from the Barnett, Bossier, Hayesville, Marcellus, Utica, and Woodford Formations and horizontal wells producing from deeper overpressure formations such as the Cotton Valley, Mississippian, and Pennsylvanian formations.
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.
Vertical well	An oil or gas well that is drilled vertically into the ground.
Water saturation	The percentage of the pore space that is occupied with water.
Well log	A device that records physical parameters of rock in the wellbore during or after drilling or the data obtained by these devices.
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.
Working interest	An entity's ownership relative to cost and expenses.
WTI	West Texas Intermediate

NETHERLAND, SEWELL & ASSOCIATES, INC.

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SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2024

SUMMARY-CERTAIN PROPERTIES
LOUISIANA-OKLAHOMA-TEXAS AREA
UNITED STATES

DEC ACQUISITION INTEREST

PROVED DEVELOPED 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	NET RESERVES EQUIV MBOE	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 TOTAL M$
12-31-2024	4,774.6	188,309.0	589.3	790.3	34,293.2	7,095.1	72.36	11.94	2.448	42,640.2	9,435.6	83,937.6	136,013.4
12-31-2025	3,933.9	167,227.8	481.5	706.5	30,727.6	6,309.2	69.06	10.78	3.276	33,250.3	7,614.1	100,662.0	141,526.4
12-31-2026	3,412.2	151,224.8	417.2	639.7	27,927.7	5,711.5	66.11	9.75	3.612	27,581.1	6,234.3	100,889.4	134,704.9
12-31-2027	3,020.6	138,120.3	369.5	582.2	25,571.7	5,213.7	64.06	9.02	3.644	23,669.3	5,253.6	93,189.0	122,112.0
12-31-2028	2,707.7	126,725.5	331.3	534.9	23,540.1	4,789.5	62.76	8.57	3.589	20,793.7	4,583.8	84,478.8	109,856.2
12-31-2029	2,446.3	116,063.4	299.1	489.7	21,617.6	4,391.8	62.03	8.32	3.494	18,555.8	4,072.6	75,535.3	98,163.7
12-31-2030	2,227.5	106,756.5	272.5	450.6	19,936.0	4,045.8	61.68	8.18	3.435	16,808.1	3,685.0	68,482.7	88,975.8
12-31-2031	2,040.1	98,414.8	249.4	415.2	18,410.7	3,733.1	61.57	8.10	3.389	15,358.9	3,361.7	62,392.0	81,112.5
12-31-2032	1,873.4	90,869.1	229.0	383.7	17,014.0	3,448.3	61.50	8.08	3.381	14,081.6	3,099.8	57,530.3	74,711.7
12-31-2033	1,728.8	84,441.6	211.5	357.3	15,834.1	3,207.8	61.15	7.96	3.437	12,931.6	2,846.1	54,424.7	70,202.4
12-31-2034	1,603.7	78,833.6	196.2	333.8	14,787.4	2,994.5	60.97	7.90	3.526	11,961.1	2,636.3	52,147.1	66,744.6
12-31-2035	1,492.0	73,787.2	182.4	312.3	13,844.9	2,802.1	60.97	7.90	3.686	11,120.1	2,466.9	51,033.3	64,620.3
12-31-2036	1,387.7	68,947.0	169.0	291.3	12,935.2	2,616.2	60.98	7.92	3.793	10,307.0	2,307.9	49,062.1	61,677.1
12-31-2037	1,289.4	63,876.4	156.5	270.4	11,987.7	2,424.9	60.99	7.95	3.794	9,544.5	2,148.5	45,478.2	57,171.2
12-31-2038	1,196.5	59,146.1	144.7	250.4	11,107.6	2,246.5	60.99	7.97	3.793	8,828.9	1,997.0	42,135.0	52,960.8
SUBTOTAL . . .	35,134.2	1,612,743.1	4,299.0	6,808.5	299,535.4	61,030.1	64.53	9.07	3.410	277,432.2	61,743.2	1,021,377.6	1,360,553.0
REMAINING . .	13,017.2	625,242.1	1,314.7	2,402.3	114,166.0	22,744.7	61.18	9.03	3.780	80,432.6	21,687.9	431,489.5	533,610.0
TOTAL	48,151.5	2,237,985.2	5,613.7	9,210.8	413,701.4	83,774.7	63.75	9.06	3.512	357,864.7	83,431.2	1,452,867.1	1,894,163.0
CUM PROD . . .	433,680.3	13,427,786.5											
ULTIMATE. . . .	481,831.8	15,665,771.7											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/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$	PRESENT WORTH PROFILE DISC RATE %	PRESENT WORTH PROFILE CUM PW M$
12-31-2024 . . .	4,938	1,367.4	5,269.0	2,367.3	0.0	399.5	51,071.6	76,905.9	76,905.9	73,484.7	5.000	617,458.4
12-31-2025 . . .	4,897	1,361.6	5,381.2	2,694.7	0.0	399.5	47,602.9	85,448.1	162,354.0	147,662.8	6.000	584,996.6
12-31-2026 . . .	4,877	1,358.9	5,083.2	2,642.8	0.0	399.5	44,904.4	81,675.0	244,029.0	212,110.0	7.000	555,342.2
12-31-2027 . . .	4,840	1,350.6	4,595.2	2,415.0	0.0	399.5	42,550.0	72,152.2	316,181.2	263,862.3	8.000	528,284.2
12-31-2028 . . .	4,763	1,333.2	4,127.8	2,180.1	0.0	399.5	40,265.8	62,883.0	379,064.2	304,864.0	9.000	503,590.1
12-31-2029 . . .	4,605	1,293.0	3,686.2	1,949.0	0.0	999.6	37,676.4	53,852.5	432,916.7	336,786.2	12.000	441,443.0
12-31-2030 . . .	4,417	1,242.0	3,339.2	1,766.0	0.0	1,097.4	35,402.2	47,371.0	480,287.7	362,313.6	15.000	393,185.3
12-31-2031 . . .	4,274	1,201.3	3,042.8	1,608.1	0.0	1,144.1	33,296.5	42,021.1	522,308.8	382,899.6	20.000	333,542.9
12-31-2032 . . .	4,122	1,160.0	2,801.2	1,484.2	0.0	1,360.5	31,313.8	37,752.1	560,060.8	399,713.4	25.000	290,719.7
12-31-2033 . . .	3,988	1,126.1	2,629.5	1,400.8	0.0	1,458.3	29,845.9	34,868.0	594,928.8	413,831.3	30.000	258,535.0
12-31-2034 . . .	3,922	1,108.4	2,497.3	1,337.6	0.0	1,581.7	28,644.1	32,683.9	627,612.7	425,862.2		
12-31-2035 . . .	3,868	1,093.7	2,414.2	1,302.9	0.0	1,751.2	27,612.7	31,539.3	659,152.0	436,416.6		
12-31-2036 . . .	3,833	1,086.6	2,301.5	1,250.6	0.0	1,895.2	26,486.8	29,743.0	688,895.0	445,465.5		
12-31-2037 . . .	3,727	1,056.2	1,132.8	1,161.8	0.0	2,039.2	25,048.6	26,788.8	715,683.8	452,875.3		
12-31-2038 . . .	3,587	1,020.1	1,974.7	1,079.8	0.0	2,178.8	23,658.1	24,069.4	739,753.2	458,928.1		
SUBTOTAL . . .			51,275.9	26,640.5	0.0	17,503.6	525,379.8	739,753.2	739,753.2	458,928.1		
REMAINING . .			19,668.4	12,009.0	0.0	157,291.8	265,068.7	79,572.1	819,325.3	481,028.3		
TOTAL OF 50.0 YRS . . .			70,944.3	38,649.4	0.0	174,795.5	790,448.5	819,325.3	819,325.3	481,028.3		

BASED ON DEC PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TECHNICAL DISCUSSION
OAKTREE CAPITAL MANAGEMENT, L.P. INTEREST LOCATED IN THE LOUISIANA-OKLAHOMA-TEXAS AREA, UNITED STATES
AS OF JANUARY 1, 2024

1.0 EXECUTIVE SUMMARY

At the request of Diversified Energy Company PLC (DEC) and Stifel Nicolaus Europe Limited, Netherland, Sewell & Associates, Inc. (NSAI) has estimated the proved developed reserves and future revenue, as of January 1, 2024, to the DEC Acquisition interest in certain oil and gas properties located in the Louisiana-Oklahoma-Texas Area of the United States. It is our understanding that DEC plans to purchase the Oaktree Capital Management, L.P. (Oaktree) interest in these properties and that the properties evaluated in this report and will be included within DEC's Central Division. DEC currently owns an interest in approximately 99.8 percent of the properties evaluated in this report. This report has been prepared using price and cost parameters specified by DEC. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates in this report have been prepared in accordance with the requirements of the Listing Rules published by the Financial Conduct Authority (FCA) and the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA (Primary Market TN 619.1), and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). This report has been prepared for use by DEC in connection with a Class 1 transaction proposed to be undertaken by DEC in accordance with the Listing Rules. In our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

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.

We estimate the net proved developed reserves, gross number of economic wells, and future net revenue to the DEC Acquisition interest in these properties, as of January 1, 2024, to be:

Evaluated Assets	Total
Net Proved Developed Reserves	
Oil (MBBL)	5,613.7
NGL (MBBL)	9,210.8
Gas (MMCF)	413,701.4
Oil Equivalent (MBOE)	83,774.7
Gross Number of Economic Wells	4,938
Future Net Revenue (M$)	
Undiscounted	819,325.3
Discounted at 10%	481,028.3

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 ft (MMCF) at standard temperature and pressure bases. Oil equivalent volumes shown in this report are expressed in thousands of barrels of oil equivalent (MBOE), determined using the ratio of 6 MCF of gas to 1 barrel of oil.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Proved developed reserves include proved developed producing and proved developed shut-in wells only. Our study indicates that as of January 1, 2024, there are no proved developed non-producing or proved undeveloped reserves for these properties. No study was made to determine whether probable or possible reserves might be established for these properties. 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.

Gross revenue shown in this report is the interest owner's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for the interest owner's share of production taxes, ad valorem taxes, 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.

DEC is an oil and gas company founded in 2001 with headquarters in Birmingham, Alabama. DEC focuses on acquiring wells in developed areas with stable and reasonably predictable production throughout the United States. DEC's asset base includes interest in approximately 74,515 wells in multiple states producing oil and natural gas which, with processing, also includes the sale of NGL. The properties are geographically separated between the Central, Northern, and Southern Divisions. A map of the DEC assets by division prior to the Oaktree acquisition in the Louisiana-Oklahoma-Texas Area is shown in Figure 1.

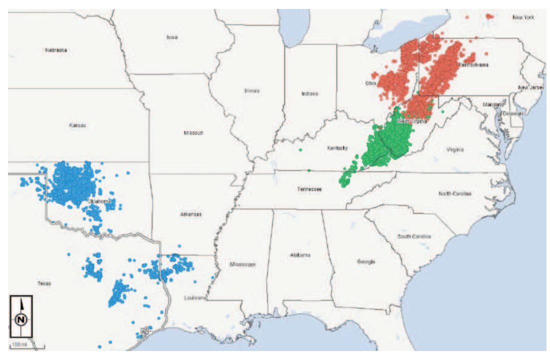

Figure 1 - DEC Assets for the Central (Blue), Northern (Red), and Southern (Green) Divisions Prior to the Oaktree Acquisition

2.0 GENERAL INFORMATION

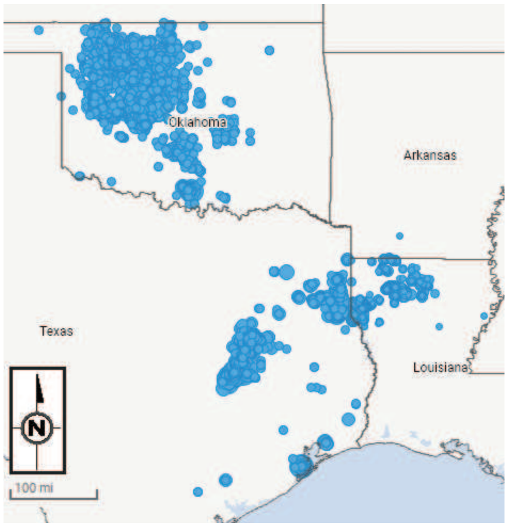

Figure 2 - Evaluated Properties in the Oaktree Acquisition

The properties evaluated in this Competent Person's Report (CPR) are located onshore in the Louisiana-Oklahoma-Texas Area of the United States, as shown in the location map in Figure 2. Included in this evaluation are 8,918 vertical and 1,661 horizontal wells producing from various formations in Arkansas, Louisiana, Oklahoma, and Texas. Each well may have one or multiple land leases with different terms, duration, and other principal conditions of these rights including environmental and abandonment obligations. In general, once a well begins producing, the leases remain in effect until production operations cease on the lease. All wells have accessibility to the properties; availability of power, water, human resources; and meet occupational health and safety requirements. DEC plans to purchase 100 percent of the Oaktree interest in these properties. Oaktree does not operate any of these wells.

We have not independently verified the accuracy and completeness of information and data furnished by DEC with respect to 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.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the DEC Acquisition 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 the interest owner receiving its net revenue interest share of estimated future gross production. In addition, no consideration has been given to any potential future gas curtailment activities or changes in market conditions.

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. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

NSAI has not previously prepared a CPR covering these properties. As such, there is no reconciliation with the last CPR published by DEC.

In accordance with the FCA guidelines on historical production (FCA Appendix III, vi.), the following table depicts the DEC Acquisition interest historical net production and net operating cost for the previous four years, as provided by DEC.

Parameter	2020[(1)]	2021	2022	2023
Net Production (MBOE/day)	N/A	5.9	18.5	23.0
Net Operating Cost ($/BOE)	N/A	8.54	12.56	10.55

(1) DEC and Oaktree acquired their interest in these properties in 2021; therefore, no data are available for 2020.

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Certificates of qualification for the evaluators who contributed to this report are shown following the definitions. 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 and 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.

3.0 DATA SOURCES

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. Information provided for this evaluation included historical production data, results of drilling and workover activity, lease operating statements containing historical revenue and operating cost information, and ownership information. If something came to our attention regarding the accuracy of the data provided, we checked public records where available, compared the data provided to similar types of properties operated by other companies, or requested additional supporting documentation from DEC.

4.0 GEOLOGY AND GEOPHYSICS

The properties evaluated in this CPR are located in the East Texas-North Louisiana and Anadarko Basins and will be included in DEC's Central Division (Figure 1). The following sections describe the geology of these basins as well as their oil and gas development history.

4.1 EAST TEXAS-NORTH LOUISIANA BASIN

The East Texas-North Louisiana Basin extends across eastern Texas and northwestern Louisiana and covers an area of approximately 15,000 square miles. Deposition in the East Texas-North Louisiana Basin was continuous throughout Jurassic and Cretaceous time. The productive stratigraphic interval ranges from 1,000 feet (ft) to over 15,000 ft in depth. The main productive reservoirs in the basin, from oldest to youngest, are the Upper Jurassic Haynesville and Bossier Shales, Upper Jurassic Cotton Valley Sandstones, Lower Cretaceous Travis Peak (Hosston) Sandstones, and various shallower Upper Cretaceous sandstones and carbonates. The basin has produced oil and gas since the early 1900s, with over 200,000 completed vertical oil and gas wells producing a cumulative 5.30 billion barrels of oil and 55 trillion cubic ft (TCF) of gas. Horizontal wells have produced over 0.08 billion barrels of oil and 45 TCF of gas from over 13,000 wells. A stratigraphic column of the East Texas-North Louisiana Basin is shown in Figure 3.

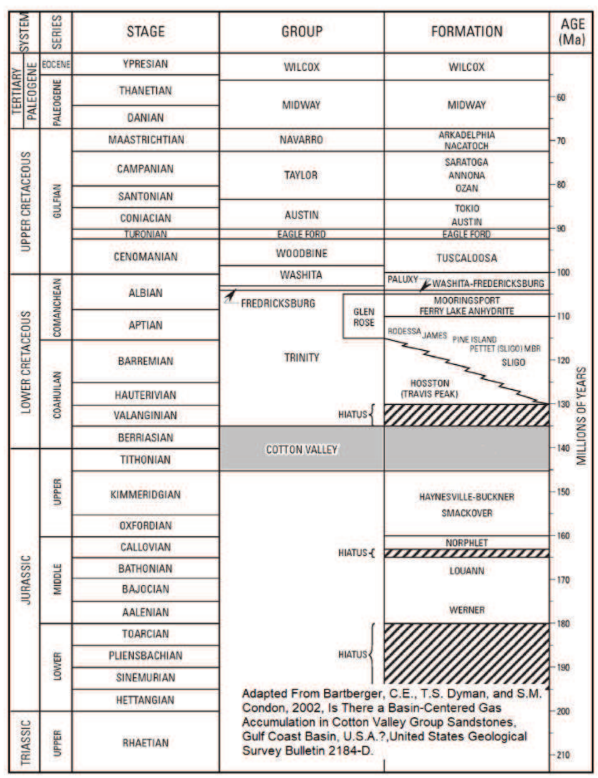

Figure 3 - Stratigraphic Column - East Texas-North Louisiana Basin

4.1.1 Central Division – Haynesville and Bossier Shales Development

The unconventional Upper Jurassic Haynesville and Middle Bossier Shales began producing from horizontal drilling in 2008; since then, more than 5,000 horizontal wells have been drilled and completed. The majority of completions have been in the Haynesville Shale reservoir, which ranges in thickness from less than 100 ft in the eastern North Louisiana portion of the play to over 400 ft in the East Texas portion of the play. Typical producing depths range from 10,000 to 13,000 ft true vertical depth (TVD), with typical horizontal completion lengths ranging from 4,000 to 9,000 ft.

The Middle Bossier Shale reservoir ranges in thickness from less than 200 ft to over 500 ft. Typical producing depths, although shallower than the Haynesville Shale, range from 11,000 to 14,000 ft TVD because development has taken place in the deeper Louisiana side of the play. Typical horizontal completion lengths, similar to the Haynesville Shale, range from 4,000 to 9,000 ft.

4.1.2 Central Division – Cotton Valley Sandstone Development

The development of the Upper Jurassic Cotton Valley Sandstone began from vertical field development as early as the 1950s with over 6,000 vertical completions. Horizontal drilling began in the early 1990s but became prevalent in the mid-2000s. Since then, more than 1,000 horizontal wells targeting the Cotton Valley Sandstone have been drilled and completed.

The Cotton Valley Sandstone reservoir ranges in thickness from less than 200 ft to over 500 ft. Typical producing depths of the Cotton Valley Sandstone range from 7,000 to 13,000 ft TVD, with typical horizontal completion lengths ranging from 2,500 to 9,000 ft.

4.1.3 Central Division – Travis Peak (Hosston) Sandstones Development

The Upper Cretaceous Travis Peak (called Hosston in Louisiana) Sandstones have been developed similarly to the Cotton Valley Sandstone since the 1950s, with vertical development of more than 6,000 wells and horizontal activity starting in the mid-2000s. Since then, more than 400 horizontal wells targeting these shallower reservoirs have been drilled.

4.2 ANADARKO BASIN

The Anadarko Basin is located in western Oklahoma and the Eastern Panhandle of Texas and covers an area of approximately 22,000 square miles. The Anadarko Basin contains as much as 25,000 ft of sedimentary rocks mostly deposited during Devonian, Mississippian, and Pennsylvanian time. The productive stratigraphic interval ranges from 1,000 ft 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 with over 300,000 vertical wells producing a cumulative 4.5 billion barrels of oil and 92 TCF of gas.

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, producing a cumulative 1.6 billion barrels of oil and 23 TCF of gas from over 25,000 wells. A stratigraphic column of the Anadarko Basin is shown in Figure 4.

4.2.1 Central Division – SCOOP-STACK Development

The majority of vertical wells in the SCOOP-STACK area of the Anadarko Basin produce from the Mississippian and Pennsylvanian formations at depths of between 1,000 and 20,000 ft TVD. Horizontal wells produce from the Mississippian carbonates in the SCOOP-STACK area of the Anadarko Basin and from various Pennsylvanian and granite wash reservoirs in the deeper portion of the Anadarko Basin. Typical horizontal producing depths range from 5,000 to 15,000 ft TVD, with typical horizontal completion lengths ranging from 3,500 to 12,000 ft.

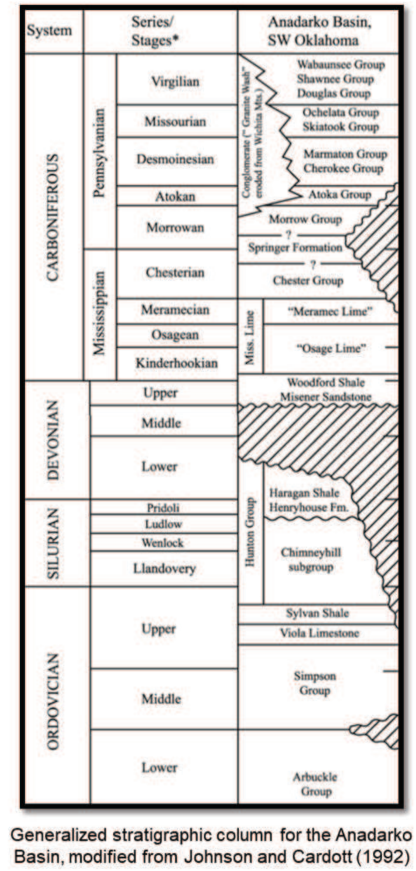

Figure 4 - Stratigraphic Column - Anadarko Basin

5.0 CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS

Included in this evaluation are 8,143 conventional and 2,436 unconventional wells producing oil and natural gas which, with processing, also includes the sale of NGL. For the purposes of this report, unconventional wells include only wells producing from the Bossier, Haynesville, Marcellus, Utica, and Woodford Formations and horizontal wells producing from deeper overpressure formations such as the Cotton Valley, Mississippian, and Pennsylvanian formations. All other wells included in this report are considered conventional wells. A summary of the conventional and unconventional wells as of January 1, 2024, is shown in the following table. It should be noted that numbers in the following table do not correspond to the numbers found in the table in the report letter because of certain summary-level abandonment expense cases.

Evaluated Assets	Conventional	Unconventional	Total
Gross Number of Economic Wells	3,164	1,774	4,938
Net Oil Equivalent Reserves (MBOE)	28,277.5	55,497.2	83,774.7
Future Net Revenue[1] (M$)			
Undiscounted	316,037.3	678,083.4	994,120.8
Discounted at 10%	157,242.3	339,628.4	496,870.7
Percent of Total[1][2]	31.6	68.4	100.0

Totals may not add because of rounding.

(1) Values for asset retirement obligations are excluded.

(2) Percent of Total calculated based on future net revenue discounted at 10 percent.

5.1 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 natural 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 full life cycle of a conventional well can be summarized into four main phases: location preparation, drilling and completion, production operations, and abandonment or asset retirement. Since the wells evaluated in this report are existing developed wells only, activities are limited to the production operations and asset retirement phases.

The typical well pad prepared for a conventional oil or natural 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. Then vertical drilling can 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 encountered. 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.

5.2 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.

Similar to a conventional well, the full life cycle of an unconventional well can be summarized into four phases: location preparation, drilling and completion, production operations, and asset retirement. Since the wells evaluated in this report are existing developed wells only, activities are limited to the production operations and asset retirement phases.

The typical well pad site prepared for unconventional oil or natural 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 required 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 and then turn 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. In 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 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 (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.

6.0 METHODS OF RESERVES DETERMINATION

Decline curve analysis (DCA) and analogy were the primary tools for projecting reserves for these properties given that they are currently producing wells with significant historical production. These methodologies are generally considered the most reliable methods for forecasting reserves wells of this type with consistent operating conditions. In general, DCA consists of using a well's historical production characteristics to forecast future production trends. We performed two types of analysis: individual well-level DCA for all wells and area-level DCA to check well forecasts at a grouped level.

Individual well-level DCA is performed on each producing well and is the most appropriate method of evaluating the reserves for these wells. This analysis should give an accurate forecast of reserves for the current completion in each well and thus the field as a whole. This analysis can help identify variations in well performance throughout the field and areas with remaining unswept hydrocarbons. Two of the most common types of DCA are exponential decline and hyperbolic decline. One of these methods was applied to each well that was evaluated.

For all DCA, 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. For the wells in this evaluation, the typical exponential decline rate is 6 percent per year. Once the forecast parameters are estimated for each well, a month-by-month forecast of oil and gas volumes can be made for each well. An example of a graph for a typical exponential decline well is shown in Figure 5. Approximately 63 percent of the active wells evaluated in this report have been forecasted using exponential DCA.

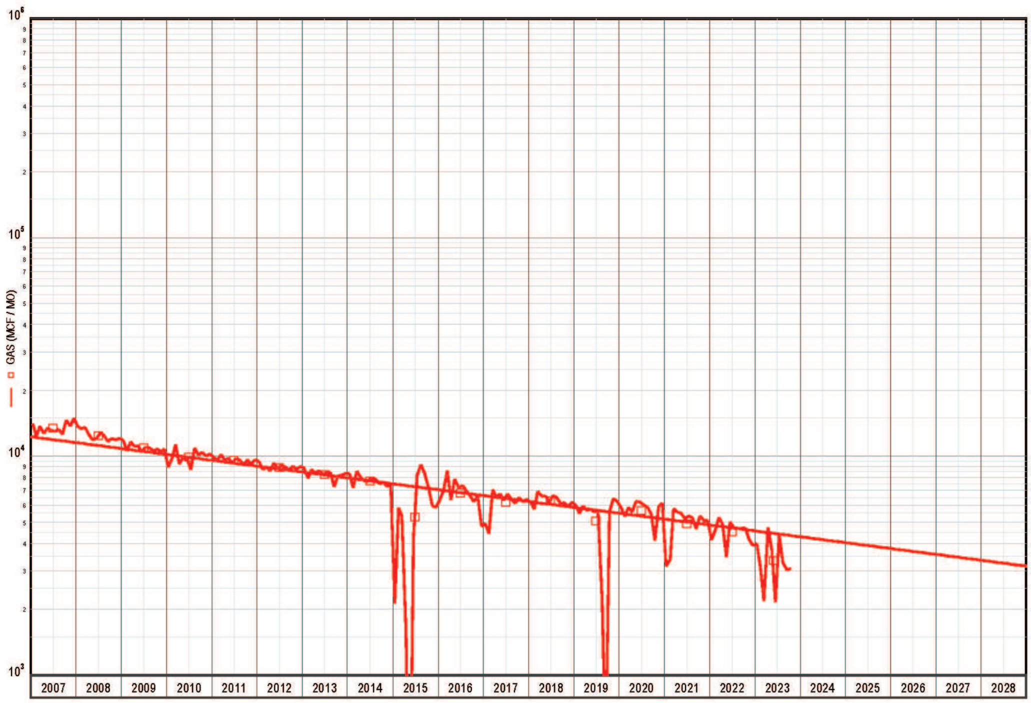

Figure 5 - Example Typical Exponential Decline Well

Many wells demonstrate a decline profile with a very high initial decline rate that decreases to a lower exponential final decline rate over time, as shown in the graph in Figure 6. Production for these wells cannot be modeled with an exponential decline curve but require 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 from 35 percent to more than 90 percent in the first year. However, the annual decline rate decreases each year that the well produces. An example of a graph for a typical hyperbolic decline well is shown in Figure 6.

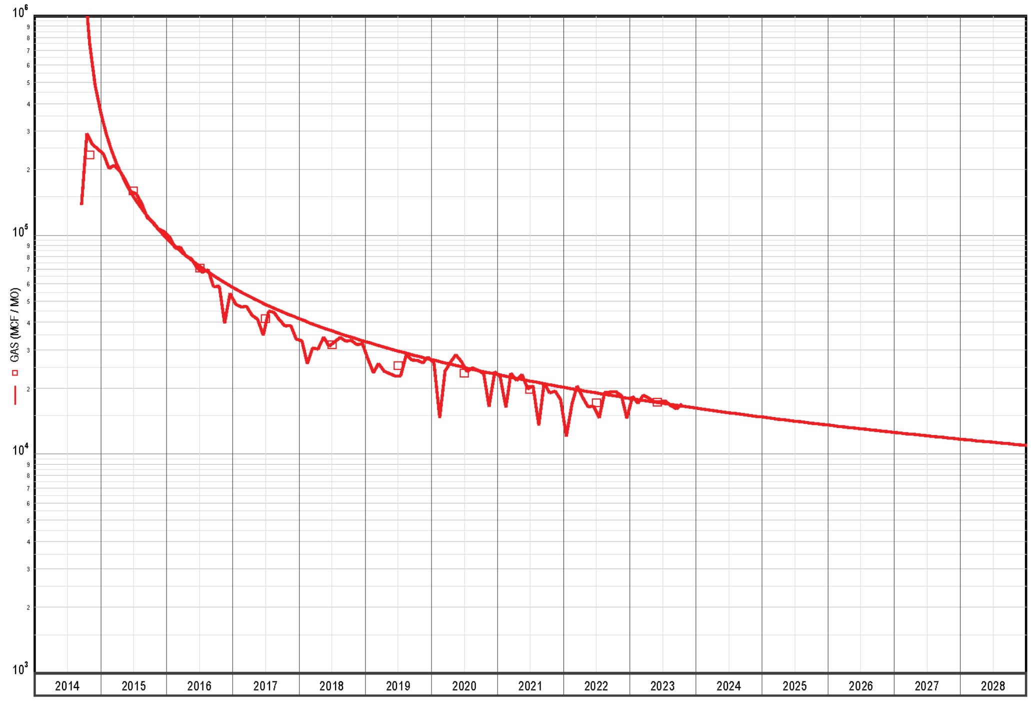

Figure 6 - Example Typical Hyperbolic Decline Well

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; in other words, the higher the b-factor, the more quickly the decline profile flattens out.

Once the decline rate reaches a predetermined value, the curved hyperbolic forecast transitions to a final exponential decline. The 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 field. The final decline rate is estimated based on analogy to other wells in the field producing from similar reservoirs. We reviewed wells with long production histories to determine the final decline rate of 6 percent and added that final decline rate for those wells forecasted with a hyperbolic decline.

As a method to check the individual well-level forecasts, well district-level DCA was used to check the summation of the individual well forecasts. For each well district, the sum of all historical oil and gas production is plotted along with the summation of the month-by-month forecasts for all producing wells. The summation of the forecasts should match the historical data on a well district-level basis.

Many of the wells evaluated in this report have produced for over 30 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, 2024).

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 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.

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 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.

7.0 INTERESTS

DEC plans to purchase 100 percent of the Oaktree interest in existing wells in the Louisiana-Oklahoma-Texas Area.

In the United States, minerals are developed on both private and public lands. The properties in this report are located on public lands. 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 natural gas that has been developed. Typically, the royalty interest is a fraction of the gross sales revenue, often 12.5 to 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. All wellbores in this acquisition are held by production.

8.0 PRODUCT PRICES

As requested, this report has been prepared using oil, NGL, and gas price parameters specified by DEC, referred to herein as the Base Case. Oil and NGL prices are based on December 29, 2023, NYMEX West Texas Intermediate prices and are adjusted for quality, transportation fees, and market differentials; for certain properties, NGL prices are negative after adjustments. Gas prices are based on December 29, 2023, NYMEX Henry Hub prices and are adjusted for energy content, transportation fees, and market differentials. The December 29, 2023, NYMEX price market forecasts do not include a price for January 2024. Oil and NGL prices for January 2024 are based on the December 19, 2023, last trading price for January of $73.44 per barrel. The gas price for January 2024 is based on the December 26, 2023, last trading day price for January of $2.619 per MMBTU. All monthly prices are averaged to determine the yearly price used in this report. As requested, although there are price hedge contracts in place for certain properties, no adjustments have been made to our estimates of future revenue to account for such contracts. Base Case prices, before adjustments, are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2024	71.68	2.670
12-31-2025	68.32	3.491
12-31-2026	65.37	3.824
12-31-2027	63.32	3.854
12-31-2028	62.02	3.798
12-31-2029	61.28	3.704
12-31-2030	60.93	3.645
12-31-2031	60.81	3.598
12-31-2032	60.73	3.590
12-31-2033	60.38	3.645
12-31-2034	60.19	3.733
12-31-2035	60.19	3.891
Thereafter	60.19	3.997

8.1 PRODUCT PRICE SENSITIVITIES

In accordance with FCA recommendations, High and Low Case price sensitivities were prepared. Oil and gas prices for the High and Low Cases are 10 percent higher and lower than the Base Case prices, respectively. A discussion of the parameters used and summary projections of reserves and revenue for the High and Low Case price sensitivities are shown in Exhibit 1. The following tables present the net proved developed reserves, gross number of economic wells, and future net revenue, as of January 1, 2024, to the DEC Acquisition interest for the High and Low Case price sensitivities.

Evaluated Assets	High Case – Base Case with a 10% Price Increase	Low Case – Base Case with a 10% Price Decrease
Net Proved Developed Reserves		
Oil (MBBL)	5,924.7	5,397.4
NGL (MBBL)	9,942.8	8,749.8
Gas (MMCF)	437,504.5	397,942.7
Oil Equivalent (MBOE)	88,784.9	80,471.0
Gross Number of Economic Wells	5,363	4,651
Future Net Revenue (M$)		
Undiscounted	1,249,930.0	625,108.3
Discounted at 10%	681,235.3	388,673.8

9.0 ECONOMIC PARAMETERS

9.1 PRICE ADJUSTMENTS

Oil price basis differentials in this report represent the difference between the oil prices realized at local or regional delivery points and the oil prices realized at Cushing, Oklahoma. Cushing, Oklahoma, is a major trading hub for crude oil and is the price settlement point for West Texas Intermediate (WTI) oil on the NYMEX. Gas price adjustments in this report 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, DEC calculated price adjustments based on the historical operating statements for the last 12 months of data or shorter periods when a full 12 months were not available. Adjustments for oil, NGL, and gas were calculated by month by comparing the actual prices received to the WTI spot prices for oil and the spot market prices at Henry Hub for gas. NGL adjustments are based on a ratio of actual prices received compared to WTI spot prices for oil and a per-barrel processing fee. NSAI reviewed the calculations prepared by DEC for reasonableness. NSAI raised questions where there were items of concern, and DEC made adjustments. NSAI accepted the adjusted values for this report. A table of differentials by well district is shown below.

Price Adjustments

Well District	Oil Price Adjustment (Fraction)	NGL Price Adjustment (Fraction)	NGL Price Adjustment ($/Barrel)	Gas Price Adjustment (Fraction)	Gas Price Adjustment ($/MMMBTU)
BLS/CASP	1.005	0.291	(3.50)	0.924	0.00
Clayton	0.955	0.000	0.00	0.800	(0.02)
Dew	0.642	0.000	0.00	0.900	(0.01)
Franklin	1.000	0.000	0.00	0.809	(0.42)
Holly East	0.994	0.385	(2.21)	0.960	0.01
Holly West	0.989	0.350	(7.46)	1.034	0.07
Kingfisher	1.009	0.363	(15.52)	0.960	(0.36)
Marshall	1.043	0.365	(11.59)	0.937	(0.31)
Minden	1.023	0.451	(4.04)	1.029	(0.01)
RCT	1.126	0.000	0.00	1.045	(0.38)
Sahara North	1.021	0.000	(15.17)	1.130	(0.67)
Sahara South	1.072	0.000	(16.06)	1.138	(0.61)
Weatherford	0.988	0.000	(16.01)	1.164	(0.52)
Woodward	1.002	0.000	(24.14)	1.116	(0.40)
Non-Operated[1]	0.978	0.366	(12.47)	1.053	(0.40)

(1) Non-Operated values are averages based on nearby well locations.

9.2 OPERATING EXPENSES

Operating costs used in this report are based on the historical 12 months of operating expense records of DEC or shorter periods when a full 12 months of data were not available. For the nonoperated properties, 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. As requested, operating costs for the operated properties include only direct lease- and field-level costs. Operating costs have been divided into per-well costs and per-unit-of-production costs. For all properties, headquarters general and administrative overhead expenses are not included. As requested, this report includes additional operating expenses for the effects of all applicable firm transportation contracts. It is our understanding that DEC is supplying all committed volumes for these contracts. As requested, operating costs are not escalated for inflation. A table of operating cost parameters by well district is shown below.

	Operating Expenses					
Well District	**Direct Fixed Cost ($/Month)**	**Direct Fixed Cost ($/Well/Month)**	**Gas Transportation Cost ($/Net MCF)**	**Gas Transportation Cost ($/Gross MCF)**	**Direct Variable Gas Cost ($/Gross MCF)**	**Direct Variable Oil Cost ($/Barrel)**
BLS/CASP	1,226	393	0.000	1.129	1.746	10.475
Clayton	1,936	388	0.179	0.000	0.173	1.038
Dew	531	475	0.287	0.000	0.202	1.212
Franklin	743	1,201	0.164	0.000	0.113	0.678
Holly East	361	973	0.000	0.259	0.985	5.911
Holly West	836	351	0.000	0.582	0.524	3.141
Kingfisher	1,141	2,302	0.000	0.033	0.641	3.846
Marshall	727	1,406	0.029	0.000	0.167	1.002
Minden	278	696	0.000	0.395	0.231	1.386
RCT	1,783	845	0.000	0.031	0.622	3.732
Sahara North	282	359	0.000	0.443	0.360	2.160
Sahara South	203	214	0.000	0.192	0.195	1.170
Weatherford	337	1,122	0.000	1.028	0.171	1.026
Woodward	1,410	2,099	0.000	0.605	0.555	3.330
Non-Operated[1]	605	1,003	0.178	0.599	0.332	1.990

(1) Non-Operated values are averages based on nearby well locations.

9.3 ABANDONMENT COSTS

Abandonment costs used in this report, further described in Section 11.0, are DEC'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.

9.4 NGL YIELDS AND GAS SHRINKAGE

NGL yields and gas shrinkage used in this report are based on the historical 12 months of operating expense records of DEC or shorter periods when a full 12 months of data were not available. NGL yields are calculated as the volume of NGL recovered from gas plants divided by the wellhead gas volume. Shrinkage is calculated as 1 minus the sales volume of natural gas divided by the historical produced gas volume. A table of average NGL yields and gas shrinkage by well district is shown below.

NGL Yields and Gas Shrinkage

Well District	Average NGL Yield (BBL/MMCF)	Average Shrinkage (%)
BLS/CASP	40.9	50.4
Clayton	0.0	9.6
Dew	0.0	6.1
Franklin	0.0	3.0
Holly East	15.6	30.4
Holly West	19.0	32.4
Kingfisher	99.9	23.0
Marshall	56.0	3.3
Minden	34.7	3.6
RCT	0.0	7.3
Sahara North	46.1	1.9
Sahara South	28.5	18.4
Weatherford	60.2	11.1
Woodward	44.8	16.8
Non-Operated	66.3	7.3

9.5 SEVERANCE AND AD VALOREM TAXES

State severance taxes and county ad valorem taxes used in this report are based on the historical 12 months of operating expense records of DEC or shorter periods when a full 12 months of data were not available. A table of severance and ad valorem tax parameters by well district is shown below.

Severance and Ad Valorem Tax

Well District	Oil/NGL/Gas Severance Tax (% of Revenue)	Ad Valorem Tax (% of Revenue)
BLS/CASP	4.4	2.6
Clayton	4.0	0.0
Dew	2.7	3.5
Franklin	3.4	4.5
Holly East	4.4	2.6
Holly West	4.4	2.6
Kingfisher	4.5	0.0
Marshall	2.7	5.4
Minden	2.1	3.0
RCT	2.7	5.4
Sahara North	4.5	0.0
Sahara South	4.5	0.0
Weatherford	4.5	0.0
Woodward	4.5	0.0
Non-Operated(1)	4.0	1.2

(1) Non-Operated values are averages based on nearby well locations.

10.0 GAS MARKETING AND TRANSPORTATION

According to DEC, it markets and sells natural gas through its wholly-owned subsidiary, Diversified Energy Marketing LLC (DEM). DEM purchases produced natural gas from Diversified Production LLC (DP), the group's production company. DP produces natural gas from wells that are connected by company-owned gathering lines. These gathering lines aggregate volumes to centralized interconnects with various third-party gathering, intrastate, and interstate pipeline systems. This interconnect with third-party lines is where DEM takes title of the natural gas volumes and typically is the point of sale between DEM and its sales counterpart. DEM markets the company's natural gas to qualified purchasers and reportedly works to maximize netback pricing via a periodic bidding process or through other forms of negotiations that occur on daily, monthly, and long-term bases.

Henry Hub is a natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for NYMEX futures contracts. Henry Hub is an important market clearing pricing concept because it is based on the actual supply and demand of natural gas as a stand-alone commodity. Other natural gas markets have fragmented hub pricing points relative to the price of oil.

DEC's Central Division gas sales are primarily tied to two different pricing regions: Gulf Coast-based indices for Texas and Louisiana Assets and Mid-Continent-based indices for Oklahoma Assets. For sales attributable to Texas and Louisiana Assets, the following S&P's Global Platts published price index points are utilized: NGPL TxOk, Columbia Gulf Mainline, Texas Gas Zone 1, and Katy, with total sales volumes being approximately 41 percent, 15 percent, 13 percent, and 4 percent, respectively. For sales attributable to the Oklahoma assets, given the optionality of the pipeline systems in this region, a Mid-Continent Weighted Average Sales Price is generally utilized, which is a combination of the following S&P's Global Platts published index points, which relative weighting may vary month to month: Transco Zone 4, Panhandle, Oneok, Okla., Southern Star, NGPL Midcontinent, and ANR, Okla., with total sales volume attributable to the Mid-Continent being approximately 27 percent. NSAI has not independently verified these reported sales volume percentages applicable to the various index points.

The remainder of the Central Division gas sales are at various other sales index points. These sales points are shown in Figure 7.

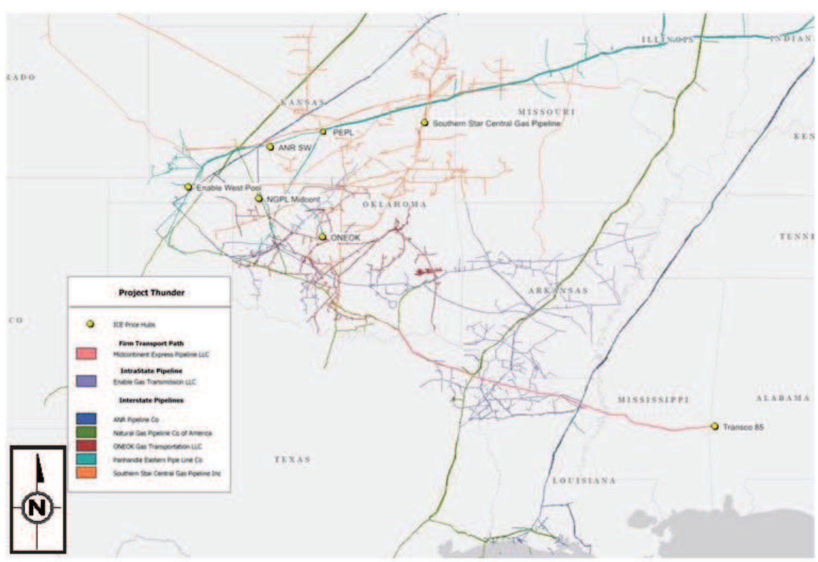

Figure 7 - Central Division Sales Points

According to DEC, DEM actively manages the company-owned transportation contracts to ensure full utilization and effective cost rationalization. This firm transportation allows volumes to be transported on interstate pipelines to various points of sale. Typically, these sales are made at "pools" that provide access to liquid markets. DEM works closely with DEC's operational teams to align sold volumes with produced volumes while also working closely with the pipeline companies to ensure that natural gas flows in a timely and accurate manner.

DEC states that once the production month is complete, DEM has an established process for invoicing counterparts that includes reconciling sales volumes on the respective pipelines and confirming all sales transactions are accurately reflected. DEM then works with the accounting department on revenue recognition by tracking and reconciling sales transactions through an established accrual and distribution process. Additionally, DEM works with the finance department on forecasting to ensure that an accurate netback pricing methodology is utilized.

11.0 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, like economic development.

Costs to plug a well can vary significantly for a number of reasons such as 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, 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.

DEC estimated the average cost to abandon wells based on historical data and applied those estimates by well type for the remaining wells. According to DEC, the wells on which the estimates were based were accessible and plugged without issues. In the future, some of the wells may require more involvement based on location, depth, and complexity. Where DEC had not plugged wells, abandonment cost estimates were based on analogy to other operators and/or areas. As requested, abandonment costs are not escalated for inflation. The gross number of wells, weighted average gross retirement expense per well, and total net retirement expense to the DEC Acquisition interest is shown in the following table.

Gross Number of Wells	Weighted Average Gross Retirement Expense Per Well (M$)	Total Net Retirement Expense (M$)	
		Undiscounted	Discounted at 10%
10,579	66.0	174,795.5	15,842.4

These assumptions were applied using two corporate summary cases that were assigned based on relevant subsets of the operating divisions. The modeled 50-year plugging schedule is shown in Figure 8. The model is held flat for the first 5 years and then escalates to a schedule of approximately 320 asset retirements per year by the year 2060. The schedule then remains level for the remaining 14 years. The asset retirement by year is depicted with the orange line, while the total cumulative expense discounted at 10 percent is represented by the blue bars. We offer no opinion to the schedule that has been presented by DEC.

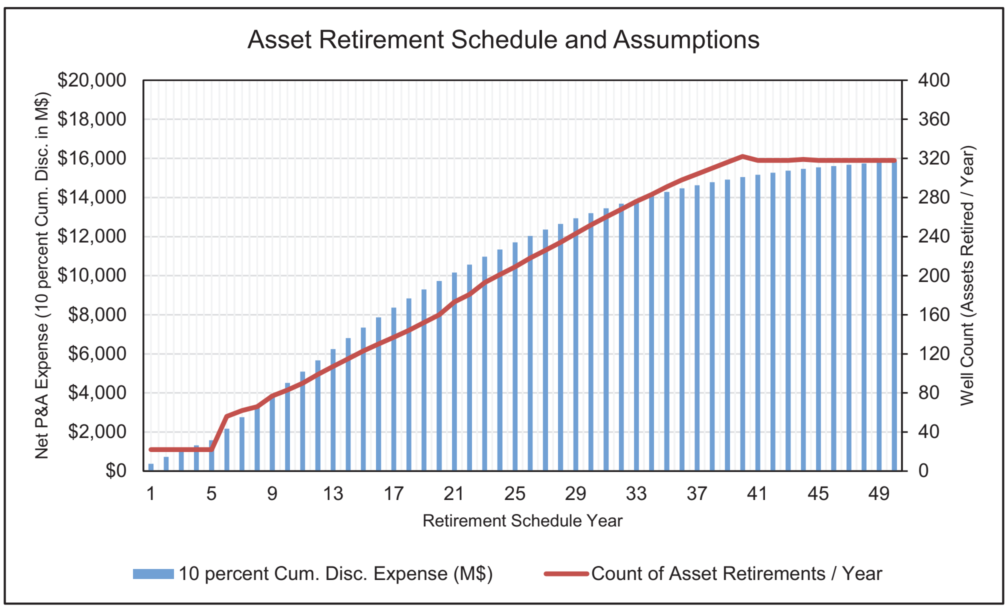

Figure 8 – Asset Retirement Schedule and Assumptions

We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

12.0 CONCLUSIONS

The estimates in this report have been prepared in accordance with the requirements of the Listing Rules published by the FCA and the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA (Primary Market TN 619.1), and the definitions and guidelines set forth in the 2018 PRMS approved by the SPE. This report has been prepared for use by DEC in connection with a Class 1 transaction proposed to be undertaken by DEC in accordance with the Listing Rules. In our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

SENSITIVITY CASES

The following sensitivities have been prepared using oil, NGL, and gas price parameters specified by DEC. The High Case price sensitivity is the Base Case with a 10 percent price increase and the Low Case price sensitivity is the Base Case with a 10 percent price decrease. Base Case oil and NGL prices are based on December 29, 2023, NYMEX West Texas Intermediate prices. Base Case gas prices are based on December 29, 2023, NYMEX Henry Hub prices. The December 29, 2023, NYMEX price market forecasts do not include a price for January 2024. Oil and NGL prices for January 2024 are based on the December 19, 2023, last trading price for January of $73.44 per barrel. The gas price for January 2024 is based on the December 26, 2023, last trading day price for January of $2.619 per MMBTU. All monthly prices are averaged to determine the yearly price. For the purposes of these sensitivities, all other parameters are the same as those described in the letter included in this report.

The following table lists the prices used for each sensitivity.

	High Case – Base Case With a 10% Price Increase		Low Case – Base Case With a 10% Price Decrease	
Period Ending	**Oil/NGL Price ($/Barrel)**	**Gas Price ($/MMBTU)**	**Oil/NGL Price ($/Barrel)**	**Gas Price ($/MMBTU)**
12-31-2024	86.74	3.231	64.51	2.403
12-31-2025	82.67	4.224	61.49	3.142
12-31-2026	79.10	4.627	58.83	3.442
12-31-2027	76.62	4.663	56.99	3.469
12-31-2028	75.04	4.596	55.82	3.418
12-31-2029	74.15	4.481	55.15	3.334
12-31-2030	73.72	4.411	54.84	3.281
12-31-2031	73.58	4.354	54.73	3.238
12-31-2032	73.48	4.344	54.66	3.231
12-31-2033	73.06	4.411	54.34	3.281
12-31-2034	72.83	4.517	54.17	3.360
12-31-2035	72.83	4.708	54.17	3.502
Thereafter	72.83	4.837	54.17	3.597

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2024

DEC ACQUISITION INTEREST

PROVED DEVELOPED RESERVES

SUMMARY-CERTAIN PROPERTIES
LOUISIANA-OKLAHOMA-TEXAS AREA
UNITED STATES

PERIOD	GROSS RESERVES		NET RESERVES				AVERAGE PRICES			GROSS REVENUE			
ENDING M-D-Y	OIL/COND MBBL	GAS MMCF	OIL/COND MBBL	NGL MBBL	GAS MMCF	EQUIV MBOE	OIL/COND $/BBL	NGL $/BBL	GAS $/MCF	OIL/COND M$	NGL M$	GAS M$	TOTAL M$
12-31-2024	4,805.1	193,017.2	593.3	813.9	35,026.0	7,244.9	87.56	17.51	3.013	51,956.0	14,252.0	105,531.2	171,739.2
12-31-2025	3,964.4	171,594.0	485.5	728.2	31,400.5	6,447.1	83.56	16.09	4.014	40,567.3	11,718.6	126,036.1	178,321.9
12-31-2026	3,440.9	155,316.0	420.8	657.5	28,524.3	5,832.3	79.99	14.83	4.421	33,657.2	9,750.3	126,109.5	169,517.1
12-31-2027	3,052.5	142,001.3	373.6	601.8	26,173.1	5,337.5	77.51	13.96	4.458	28,956.4	8,402.4	116,693.1	154,052.0
12-31-2028	2,744.3	130,463.7	335.9	553.5	24,110.2	4,907.7	75.93	13.43	4.392	25,504.1	7,430.7	105,888.4	138,823.2
12-31-2029	2,489.0	120,025.3	305.0	510.2	22,246.4	4,523.0	75.04	13.11	4.277	22,889.6	6,689.2	95,140.8	124,719.6
12-31-2030	2,270.6	110,834.8	278.7	473.1	20,611.0	4,186.9	74.62	12.96	4.207	20,793.6	6,128.9	86,712.1	113,634.6
12-31-2031	2,085.1	102,556.1	256.0	439.1	19,110.2	3,880.1	74.49	12.89	4.151	19,067.6	5,659.5	79,328.2	104,055.3
12-31-2032	1,920.4	95,147.1	235.9	408.7	17,762.3	3,605.0	74.40	12.85	4.141	17,553.7	5,253.2	73,562.7	96,369.6
12-31-2033	1,777.0	88,692.9	218.5	381.4	16,572.8	3,362.0	73.98	12.73	4.209	16,164.9	4,854.2	69,760.9	90,780.0
12-31-2034	1,649.0	82,844.5	202.9	356.6	15,492.5	3,141.6	73.75	12.64	4.317	14,966.9	4,506.3	66,878.5	86,351.8
12-31-2035	1,534.3	77,559.3	188.9	334.1	14,511.2	2,941.5	73.75	12.64	4.510	13,933.4	4,221.5	65,444.0	83,599.0
12-31-2036	1,432.5	72,561.3	176.6	313.0	13,582.9	2,753.4	73.76	12.63	4.640	13,022.3	3,953.3	63,030.2	80,005.9
12-31-2037	1,334.0	67,552.4	164.7	292.0	12,651.7	2,565.2	73.76	12.62	4.641	12,145.3	3,684.0	58,716.4	74,545.6
12-31-2038	1,242.3	62,771.2	153.3	271.7	11,760.5	2,385.1	73.77	12.59	4.642	11,308.7	3,421.4	54,593.2	69,323.3
SUBTOTAL	35,741.3	1,672,937.0	4,389.5	7,134.5	309,535.8	63,113.3	78.02	14.01	4.179	342,487.0	99,925.6	1,293,425.4	1,735,838.0
REMAINING	14,125.6	694,790.5	1,535.2	2,808.3	127,968.8	25,671.6	73.93	13.18	4.629	113,494.3	37,002.0	592,416.8	742,913.1
TOTAL	49,866.9	2,367,727.6	5,924.7	9,942.8	437,504.5	88,784.9	76.96	13.77	4.311	455,981.3	136,927.6	1,885,842.2	2,478,751.1
CUM PROD	433,680.3	13,427,786.5											
ULTIMATE	483,547.2	15,795,514.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%	PRESENT WORTH PROFILE	
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	PERIOD M$	CUM M$	CUM M$	DISC RATE %	CUM PW M$
12-31-2024	5,363	1,472.6	6,670.0	2,977.4	0.0	399.5	54,005.0	107,687.3	107,687.3	102,883.0	5.000	890,691.9
12-31-2025	5,328	1,467.7	6,801.7	3,374.1	0.0	399.5	50,450.0	117,296.6	224,983.9	204,703.2	6.000	839,505.2
12-31-2026	5,309	1,465.4	6,420.8	3,296.1	0.0	399.5	47,657.3	111,743.3	336,727.2	292,871.5	7.000	793,575.4
12-31-2027	5,277	1,460.8	5,818.1	3,023.0	0.0	399.5	45,315.7	99,495.6	436,222.8	364,232.9	8.000	752,257.4
12-31-2028	5,209	1,443.8	5,235.9	2,733.3	0.0	399.5	42,960.2	87,494.3	523,717.1	421,278.7	9.000	714,978.1
12-31-2029	5,055	1,402.1	4,702.1	2,453.8	0.0	999.6	40,572.0	75,992.1	599,709.2	466,321.4	12.000	622,673.4
12-31-2030	4,922	1,372.6	4,282.4	2,235.2	0.0	1,097.4	38,496.2	67,523.4	667,232.6	502,705.7	15.000	552,222.2
12-31-2031	4,780	1,339.2	3,922.0	2,042.2	0.0	1,144.1	36,500.5	60,446.5	727,679.1	532,315.7	20.000	466,321.2
12-31-2032	4,648	1,303.6	3,631.7	1,891.8	0.0	1,360.5	34,692.9	54,792.7	782,471.8	556,716.5	25.000	405,310.8
12-31-2033	4,529	1,272.8	3,418.4	1,788.8	0.0	1,458.3	33,227.4	50,887.2	833,359.0	577,318.2	30.000	359,776.5
12-31-2034	4,457	1,254.6	3,248.7	1,707.0	0.0	1,581.7	31,941.2	47,873.1	881,232.1	594,938.0		
12-31-2035	4,400	1,240.8	3,141.4	1,661.3	0.0	1,751.2	30,838.6	46,206.5	927,438.6	610,398.6	BASED ON DEC PRICE	
12-31-2036	4,365	1,232.1	3,004.4	1,594.2	0.0	1,895.2	29,764.2	43,747.8	971,186.4	623,706.3	AND COST PARAMETERS	
12-31-2037	4,275	1,207.9	2,799.3	1,484.4	0.0	2,039.2	28,417.3	39,805.5	1,010,991.9	634,714.5	WITH A 10 PERCENT	
12-31-2038	4,136	1,169.6	2,603.3	1,378.6	0.0	2,178.8	27,012.6	36,150.0	1,047,141.9	643,830.4	PRICE INCREASE	
SUBTOTAL . . .			65,700.0	33,641.2	0.0	17,503.6	571,851.2	1,047,141.9	1,047,141.9	643,803.4		
REMAINING . .			27,627.4	15,911.4	0.0	157,291.8	339,294.5	202,788.1	1,249,930.0	681,235.3		
TOTAL OF 50.0 YRS . . .			93,327.4	49,552.6	0.0	174,795.5	911,145.7	1,249,930.0	1,249,930.0	681,235.3		

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JANUARY 1, 2024

SUMMARY-CERTAIN PROPERTIES
LOUISIANA-OKLAHOMA-TEXAS AREA
UNITED STATES

DEC ACQUISITION INTEREST

PROVED DEVELOPED 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	NET RESERVES EQUIV MBOE	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 TOTAL M$
12-31-2024	4,749.0	184,859.8	585.7	773.6	33,752.2	6,984.6	65.13	9.25	2.178	38,145.0	7,152.6	73,499.0	118,796.6
12-31-2025	3,912.0	164,029.5	478.4	691.4	30,232.3	6,208.5	62.16	8.20	2.924	29,739.8	5,672.8	88,384.3	123,796.9
12-31-2026	3,386.9	148,221.7	414.0	626.1	27,473.1	5,619.0	59.50	7.28	3.227	24,634.8	4,555.8	88,652.9	117,843.5
12-31-2027	2,993.8	135,323.6	366.0	569.8	25,158.6	5,128.9	57.66	6.63	3.256	21,102.8	3,779.2	81,903.3	106,785.3
12-31-2028	2,676.8	123,890.1	327.0	518.5	23,075.8	4,691.4	56.49	6.25	3.205	18,471.9	3,240.5	73,950.5	95,662.9
12-31-2029	2,417.3	113,308.8	295.2	474.5	21,149.6	4,294.5	55.83	6.00	3.121	16,478.1	2,846.4	65,999.4	85,323.9
12-31-2030	2,195.3	103,869.4	267.4	435.7	19,414.3	3,938.8	55.53	5.92	3.068	14,847.8	2,577.7	59,560.0	76,985.4
12-31-2031	2,001.9	95,332.5	243.8	400.8	17,878.9	3,624.5	55.43	5.89	3.025	13,514.9	2,362.6	54,076.7	69,954.2
12-31-2032	1,838.7	88,014.9	223.4	370.1	16,531.7	3,348.8	55.37	5.90	3.018	12,370.6	2,183.5	49,893.0	64,447.1
12-31-2033	1,695.3	81,634.4	204.8	342.7	15,325.0	3,101.6	55.05	5.83	3.069	11,274.4	1,996.3	47,034.1	60,304.8
12-31-2034	1,570.6	76,052.9	189.4	319.3	14,271.3	2,887.2	54.89	5.78	3.149	10,393.2	1,846.0	44,945.7	57,184.9
12-31-2035	1,459.5	71,106.7	176.0	298.9	13,345.7	2,699.2	54.89	5.79	3.293	9,662.6	1,729.9	43,945.1	55,337.6
12-31-2036	1,354.1	66,329.0	162.7	278.5	12,456.5	2,517.3	54.90	5.80	3.389	8,929.3	1,616.1	42,209.5	52,754.9
12-31-2037	1,249.6	61,133.5	148.2	255.0	11,495.1	2,319.0	54.91	5.80	3.388	8,137.0	1,480.1	38,950.5	48,567.6
12-31-2038	1,154.2	56,388.8	135.6	232.3	10,587.9	2,132.6	54.92	5.87	3.388	7,446.4	1,364.8	35,869.1	44,680.4
SUBTOTAL	34,655.2	1,569,495.6	4,217.5	6,587.2	292,147.9	59,496.0	58.13	6.74	3.042	245,148.5	44,404.3	888,873.3	1,178,426.0
REMAINING	12,339.6	583,532.7	1,179.9	2,162.7	105,794.8	20,975.0	55.12	7.27	3.375	65,030.4	15,731.8	357,057.3	437,819.5
TOTAL	46,994.8	2,153,028.3	5,397.4	8,749.8	397,942.7	80,471.0	57.47	6.87	3.131	310,178.9	60,136.0	1,245,930.6	1,616,245.5
CUM PROD	433,680.3	13,427,786.5											
ULTIMATE	480,675.1	15,580,814.8											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/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$	PRESENT WORTH PROFILE DISC RATE %	PRESENT WORTH PROFILE CUM PW M$
12-31-2024	4,651	1,295.9	4,594.5	2,073.7	0.0	399.5	49,167.5	62,561.3	62,561.3	59,784.5	5.000	492,397.9
12-31-2025	4,623	1,292.4	4,698.0	2,366.8	0.0	399.5	45,802.5	70,530.0	133,091.3	121,015.0	6.000	468,276.5
12-31-2026	4,601	1,289.0	4,437.3	2,323.9	0.0	399.5	43,127.0	67,555.7	200,647.0	174,322.4	7.000	445,896.1
12-31-2027	4,552	1,279.3	4,009.0	2,124.6	0.0	399.5	40,832.7	59,419.5	260,066.5	216,944.6	8.000	425,231.0
12-31-2028	4,474	1,258.3	3,584.8	1,912.5	0.0	399.5	38,360.8	51,405.2	311,471.8	250,463.6	9.000	406,195.3
12-31-2029	4,295	1,205.8	3,194.2	1,707.5	0.0	999.6	35,782.7	43,639.8	355,111.6	276,333.5	12.000	357,672.9
12-31-2030	4,109	1,154.5	2,879.8	1,543.8	0.0	1,097.4	33,381.1	38,083.2	393,194.8	296,857.1	15.000	319,504.2
12-31-2031	3,911	1,105.2	2,614.6	1,407.2	0.0	1,144.1	31,248.2	33,540.1	426,734.9	313,289.5	20.000	271,870.0
12-31-2032	3,786	1,073.1	2,406.2	1,301.9	0.0	1,360.5	29,443.9	29,934.6	456,669.5	326,622.7	25.000	237,408.9
12-31-2033	3,685	1,044.0	2,248.4	1,226.1	0.0	1,458.3	27,829.0	27,543.0	484,212.5	337,775.8	30.000	211,384.7
12-31-2034	3,576	1,012.9	2,130.1	1,168.1	0.0	1,581.7	26,551.4	25,753.7	509,966.2	347,256.6		
12-31-2035	3,529	1,001.7	2,058.6	1,136.8	0.0	1,751.2	25,544.5	24,846.5	534,812.7	355,572.2		
12-31-2036	3,479	988.5	1,960.1	1,089.6	0.0	1,895.2	24,435.0	23,375.0	558,187.7	362,684.6		
12-31-2037	3,350	953.6	1,802.9	1,007.3	0.0	2,039.2	22,817.9	20,900.3	579,087.9	368,466.4		
12-31-2038	3,190	907.0	1,655.5	934.1	0.0	2,178.8	21,253.4	18,658.6	597,746.6	373,159.2		
SUBTOTAL . . .			44,274.0	23,324.0	0.0	17,503.6	495,577.8	597,746.6	597,746.6	373,159.2		
REMAINING . .			16,042.9	10,202.2	0.0	157,291.8	226,920.9	27,361.7	625,108.3	388,673.8		
TOTAL OF 50.0 YRS . . .			60,316.9	33,526.2	0.0	174,795.5	722,498.7	625,108.3	625,108.3	388,673.8		

BASED ON A DEC PRICE AND COST PARAMETERS WITH A 10 PERCENT PRICE DECREASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

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 (CPR), 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 LR 13.4.1R(6) of the Listing Rules;

(c) NSAI confirms that it is unaware of any material change in circumstances to those stated in the CPR;

(d) Robert C. Barg, Senior 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 potential acquisition assets of Diversified Energy Company PLC (DEC), which we have reported on;

(f) NSAI considers that the scope of the CPR is appropriate and was prepared to a standard expected in accordance with Primary Market TN 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 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 CPR; and

(j) NSAI is not a sole practitioner.

Part 6
UNAUDITED PRO FORMA FINANCIAL INFORMATION

Section A: Unaudited Pro Forma Financial Information

Set out below is the unaudited pro forma Statement of Financial Position of the Group as at 31 December 2023 and the unaudited pro forma Statement of Comprehensive Income for the year then ended (together, the "**Pro Forma Financial Information**") in accordance with Listing Rule 13.3.3R. The Pro Forma Financial Information has been prepared on the basis of the accounting policies adopted by the Company in preparing the audited historical financial information of the Group for the year ended 31 December 2023, to illustrate the effects of:

- the Acquisition;
- the draw down of funds from the ABS Warehouse Facility;
- the draw down of funds from the Credit Facility;
- the settlement of the associated costs,

on the assets, liabilities and equity of the Group had the proposed Acquisition, the draw down from the ABS Warehouse Facility, the draw down from the Credit Facility and settlement of the associated costs occurred on 31 December 2023 and on the earnings of the Group for the year then ended, had the proposed Acquisition, the draw down from the ABS Warehouse Facility, the draw down from the Credit Facility and settlement of the associated costs occurred on 1 January 2023, being the first day of that period.

The Pro Forma Financial Information has been prepared for illustrative purposes only. Due to its nature, the Pro Forma Financial Information addresses a hypothetical situation and, therefore, does not represent the Group's actual financial position as at 31 December 2023, or of its earnings for year then ended. It is based on the audited historical consolidated financial information of the Group for the year ended 31 December 2023 and the unaudited Target Assets' Financial Information included in Part 4 *"Financial Information Relating to the Target Assets"* of this document.

Users should read the whole of this document and not rely solely on the Pro Forma Financial Information.

The accountant's report on the Pro Forma Financial Information is set out in Section B *"Accountant's Report on the Unaudited Pro Forma Financial Information"* of Part 6 *"Unaudited Pro Forma Financial Information"* of this document.

UNAUDITED PRO FORMA STATEMENT OF FINANCIAL POSITION

	Group As at 31 December 2023 $'000 (Note 1)	*Adjustment* Acquisition $'000 (Note 2)	*Adjustment* Drawdown from ABS Warehouse Facility $'000 (Note 3)	*Adjustment* Drawdown from Credit Facility $'000 (Note 4)	*Adjustment* Settlement of associated costs $'000 (Note 5)	Pro forma balances as at 31 December 2023 $'000
Natural gas and oil properties *(net)*	2,490,375	331,527	—	—	4,578	2,826,480
Property, plant and equipment *(net)*	456,208	—	—	—	—	456,208
Intangible assets	19,351	—	—	—	—	19,351
Restricted cash	25,057	—	—	—	—	25,057
Derivative financial instruments	24,401	—	—	—	—	24,401
Deferred tax asset	144,860	—	—	—	—	144,860
Other non-current assets	9,172	—	—	—	—	9,172
Non-current assets	**3,169,424**	**331,527**	**—**	**—**	**4,578**	**3,505,529**
Trade receivables *(net)*	190,207	—	—	—	—	190,207
Cash and cash equivalents	3,753	(178,168)	75,000	107,746	(4,578)	3,753
Restricted cash	11,195	6,114	—	—	—	17,309
Derivative financial instruments	87,659	72,152	—	—	—	159,811
Other current assets	11,784	—	—	—	—	11,784
Current assets	**304,598**	**(99,902)**	**75,000**	**107,746**	**(4,578)**	**382,864**
Total assets	**3,474,022**	**231,625**	**75,000**	**107,746**	**—**	**3,888,393**
Share capital	12,897	—	—	—	—	12,897
Share premium	1,208,192	—	—	—	—	1,208,192
Treasury reserve	(102,470)	—	—	—	—	(102,470)
Share-based payment and other reserves	14,442	—	—	—	—	14,442
Accumulated deficit	(547,255)	—	—	—	—	(547,255)
Equity attributable to the owners of the Company	585,806	—	—	—	—	585,806
Non-controlling interest	12,604	—	—	—	—	12,604
Equity	**598,410**	**—**	**—**	**—**	**—**	**598,410**
Asset retirement obligations	501,246	—	—	—	—	501,246
Leases	20,559	—	—	—	—	20,559
Borrowings	1,075,805	124,510	75,000	107,746	—	1,383,061
Deferred tax liability	13,654	—	—	—	—	13,654
Derivative financial instruments	623,684	—	—	—	—	623,684
Other non-current liabilities	2,224	38,168	—	—	—	40,392
Non-current liabilities	**2,237,172**	**162,678**	**75,000**	**107,746**	**—**	**2,582,596**
Trade and other payables	53,490	16,000	—	—	—	69,490
Taxes payable	50,226	—	—	—	—	50,226
Leases	10,563	—	—	—	—	10,563
Borrowings	200,822	33,604	—	—	—	234,426
Derivative financial instruments	45,836	—	—	—	—	45,836
Other current liabilities	277,503	19,343	—	—	—	296,846
Current liabilities	**638,440**	**68,947**	**—**	**—**	**—**	**707,387**
Total liabilities	**2,875,612**	**231,625**	**75,000**	**107,746**	**—**	**3,289,983**
Total equity and liabilities	**3,474,022**	**231,625**	**75,000**	**107,746**	**—**	**3,888,393**

UNAUDITED PRO FORMA STATEMENT OF COMPREHENSIVE INCOME

	Group Year ended 31 December 2023 $'000 (Note 1)	*Adjustment* Acquisition $'000 (Note 2)	*Adjustment* Drawdown from ABS Warehouse Facility $'000 (Note 3)	*Adjustment* Drawdown from Credit Facility $'000 (Note 4)	*Adjustment* Settlement of associated costs $'000 (Note 5)	Pro forma results for the year ended 31 December 2023 $'000
Revenue	868,263	177,430	—	—	—	1,045,693
Operating expense	(440,562)	(88,397)	—	—	—	(528,959)
Depreciation, depletion and amortisation	(224,546)	—	—	—	—	(224,546)
Gross profit	**203,155**	**89,033**	**—**	**—**	**—**	**292,188**
General and administrative expense	(119,722)	—	—	—	—	(119,722)
Allowance for expected credit losses	(8,478)	—	—	—	—	(8,478)
Gain on natural gas and oil property and equipment	24,146	—	—	—	—	24,146
Gain on sale of equity interest	18,440	—	—	—	—	18,440
Unrealised gain on investment	4,610	—	—	—	—	4,610
Gain on derivative financial instruments	1,080,516	24,829	—	—	—	1,105,345
Impairment of proved properties	(41,616)	—	—	—	—	(41,616)
Operating profit	**1,161,051**	**113,862**	**—**	**—**	**—**	**1,274,913**
Finance costs	(134,166)	(18,913)	(6,855)	(9,848)	—	(169,782)
Accretion of asset retirement obligation	(26,926)	—	—	—	—	(26,926)
Other income	385	—	—	—	—	385
Income/(loss) before taxation	**1,000,344**	**94,949**	**(6,855)**	**(9,848)**	**—**	**1,078,590**
Income tax (expense)/credit	(240,643)	(22,883)	1,652	2,373	—	(259,501)
Net income/(loss)	**759,701**	**72,066**	**(5,203)**	**(7,475)**	**—**	**819,089**
Other comprehensive loss	(270)	—	—	—	—	(270)
Total comprehensive income/(loss)	**759,431**	**72,066**	**(5,203)**	**(7,475)**	**—**	**818,819**

NOTES

1. The financial information of the Group as at 31 December 2023 has been extracted, without adjustment, from pages 143 and 144 of the Group's audited consolidated financial information for the year ended 31 December 2023 as available on the Company's website at www.ir.div.energy/financial-information.

   The Pro Forma Financial Information has been prepared on the basis of the accounting policies adopted by the Company in preparing the audited historical financial information of the Group for the year ended 31 December 2023.

2. The adjustment to the pro forma Statement of Financial Position represents the acquisition of the Target Assets by the Group and financing supplied by the Seller.

   With respect to the unaudited pro forma Statement of Financial Position, the Group is acquiring Target Assets comprising assets and liabilities as follows:

   - $369,848,000 of *"natural gas and oil properties"* within *"non-current assets"*;
   - $6,114,000 of *"restricted cash"* within *"current assets"*;
   - $72,152,000 of *"derivative financial assets"* within *"current assets"*; and
   - $158,114,000 of *"Borrowings"*, of which $33,604,000 are included in *"current liabilities"* and $124,510,000 within *"non-current liabilities"*;
   - $16,000,000 of post-effective date cash included in *"trade and other payables"* within *"current liabilities"*; and
   - $7,664,000 of amounts due to third parties included in *"other current liabilities"* within *"current liabilities"*.

   The aggregate of the above results in net consideration payable to the Sellers of $266,336,000, which is satisfied by:

   - a cash payment of $178,168,000, resulting in a decrease to *"cash and cash equivalents"* within *"current assets"* by this amount;
   - deferred consideration of $50,000,000, payable on 6 months and 12 months at $25,000,000 each and recorded as an increase to *"other current liabilities"* within *"current liabilities"*; and
   - deferred consideration of $38,168,000, payable on 18 months and recorded as an increase to *"other non-current liabilities"* within *"non-current liabilities"*.

   In addition to the above, cash owed by the Group to the Sellers as at 31 December 2023 of $38,321,000 will be forgiven. This results in decreases to both *"natural gas and oil properties"* within *"non-current assets"* and *"other current liabilities"* within *"current liabilities"* of this amount.

   With respect to the unaudited pro forma Statement of Comprehensive Income, the adjustment represents the results of the Target Assets for the year ended 31 December 2023, as extracted, without adjustment, from the unaudited financial information of the Target Assets included in Part 4 *"Unaudited Financial Information Relating to the Target Assets"* of this document. The results of the Target Assets for the year result in an increase to *"revenue"* of $177,430,000, *"operating expenses"* of $88,397,000 and to *"gross profit"* of $89,033,000. After recording a gain on derivative financial instruments of $24,829,000 for the year, an operating profit of $113,862,000 was recorded for the year. The Target Assets incurred an interest charge of $12,859,000 in relation to the ABS VI notes, which results in an increase to *"finance costs"* for the year ended 31 December 2023.

   On the basis that the Seller is providing finance to the Group to the value of $88,168,000, decreasing to $63,168,000 following payment of the initial $25,000,000 on 6 months, an interest charge of $6,054,000 has been included within *"finance cost"* for the year, calculated at the facility's annual interest rate of 8.0%. Following these aggregate interest charges of $18,913,000, the adjustment to *"income before taxation"* is an increase of $94,949,000 for the year which, at the Group's effective tax rate for the year ended 31 December 2023 of 24.1%, results in a pro forma tax charge for the year of $22,883,000, included within *"income tax (expense)/credit"*.

3. The adjustment represents the draw down from the ABS Warehouse Facility to the value of $75,000,000.

   With respect to the unaudited pro forma Statement of Financial Position, the draw down from the ABS Warehouse Facility results in an increase to *"cash and cash equivalents"* of $75,000,000 within *"current assets"*, together with an increase of $75,000,000 to *"borrowings"* within *"non-current liabilities"*.

   With respect to the unaudited pro forma Statement of Comprehensive Income, an interest charge of $6,855,000 is included within *"finance costs"* for the year ended 31 December 2023, calculated at the ABS Warehouse Facility's annual interest rate of SOFRA plus 3.75%. Associated with this finance cost is an pro forma tax credit of $1,652,000, included within *"income tax (expense)/credit"*, calculated at the Group's effective tax rate for the year ended 31 December 2023 of 24.1%.

4. The adjustment represents the draw down of funds to the value of $107,746,000 from the Group's existing Credit Facility.

   With respect to the unaudited pro forma Statement of Financial Position, the draw down of funds results in an increase to *"cash and cash equivalents"* of $107,746,000 within *"current assets"*, together with an increase of $107,746,000 to *"borrowings"* within *"non-current liabilities"*.

   With respect to the unaudited pro forma Statement of Comprehensive Income, an interest charge of $9,848,000 is included within *"finance costs"* for the year ended 31 December 2023, calculated at the Credit Facilities annual interest rate of SOFRA plus 3.75%. Associated with this finance cost is an pro forma tax credit of $2,373,000, included within *"income tax (expense)/credit"*, calculated at the Group's effective tax rate for the year ended 31 December 2023 of 24.1%.

5. The adjustment represents the settlement of the costs of the proposed Acquisition. The costs are $4,578,000 and their settlement results in a decrease to *"cash and cash equivalents"* within *"current assets"* of $4,578,000 and an increase to the carrying value of *"oil and gas properties"* within *"non-current assets"* of $4,578,000.

   This adjustment has no effect on the unaudited pro forma Statement of Comprehensive Income.

6. With respect to the above adjustments, none will have an ongoing effect on the results of the Group.

Section B: Accountants' Report on the Unaudited Pro Forma Financial Information

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9 May 2024

The Directors
Diversified Energy Company PLC
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1 Station Hill
Reading
Berkshire RG1 1NB

Stifel Nicolaus Europe Limited
4th Floor
150 Cheapside
London EC2V 6ET

Dear Sirs and Madams,

Introduction

We report on the unaudited pro forma Statement of Financial Position of Diversified Energy Company PLC (the "**Company**") as at 31 December 2023 and on the unaudited pro forma Statement of Comprehensive Income for the year then ended (together, the "**Pro Forma Financial Information**") set out in Section A "*Unaudited Pro Forma Financial Information*" of Part 7 *"Unaudited Pro Forma Financial Information"* of the Company's circular dated 9 May 2024 (the "**Circular**").

Opinion

In our opinion:

- the Pro Forma Financial Information has been properly compiled on the basis stated; and
- such basis is consistent with the accounting policies of the Company.

Responsibilities

It is the responsibility of the directors of the Company (the "**Directors**") to prepare the Pro Forma Financial Information in accordance with item 13.3.3R of the Listing Rules.

It is our responsibility to form an opinion, as required by item 13.3.3R of the Listing Rules, 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 used in the compilation of the Pro Forma Financial Information. In providing this opinion, we are not providing any assurance on any source financial information on which the Pro Forma Financial Information is based beyond the above opinion.

Basis of preparation

The Pro Forma Financial Information has been prepared on the basis described, for illustrative purposes only, to provide information about how:

- the acquisition of certain assets from OCM Denali Int Holdings PT, LLC, a subsidiary of Oaktree Capital Management, L.P. by the Company;

- the draw down of funds from the Group's ABS warehouse facility;
- the draw down of funds from the Group's reserve-based lending facility; and
- the settlement of costs associated with the proposed Acquisition,

might have affected the assets, liabilities, equity, and earnings presented on the basis of the accounting policies adopted by the Company in preparing the audited, consolidated financial information of the Company and its subsidiaries for the year ended 31 December 2023. This report is required by item 13.3.3R of the Listing Rules and is given for the purpose of complying with that requirement and for no other purpose.

Basis of opinion

We conducted our work in accordance with Standards of Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent of the Company and Oaktree Capital Management, L.P. in accordance with the Financial Reporting Council's Ethical Standard, 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 all the information and explanations which 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 purpose of item 13.3.3R of the Listing Rules, we are responsible for this report as part of the Document and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import. This declaration is included in the Document in compliance with item 13.3.3R of the Listing Rules.

Yours faithfully,

Crowe U.K. LLP

Chartered Accountants

Part 7
ADDITIONAL INFORMATION

1. Responsibility

The Company and its Directors, whose names appear in paragraph 3 of this Part 7 (''*Additional Information*''), accept responsibility for the information contained in this document. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

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 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 Ordinary Shares have been created is the Companies Act 2006. The Ordinary Shares have been duly authorised according to the requirements of the Company's constitution and have all necessary statutory and other consents. As at the Latest Practicable Date, the Company has 47,568,429 Ordinary Shares in issue and the Company does not hold any Ordinary Shares in treasury.

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. Directors and Senior Managers

3.1 Directors

The current Directors and their functions are as follows:

Name	Position	Date appointed to the Board	Age
David Edward Johnson	Non-Executive Chair	3 February 2017	63
Robert ''Rusty'' Russell Hutson, Jr.	Chief Executive Officer	31 July 2014	54
Martin Keith Thomas	Non-executive Vice Chair	1 January 2015	59
Sylvia Kerrigan	Non-Executive Director and Senior Independent Director	11 October 2021	58
David Jackson Turner, Jr.	Non-Executive Director	27 May 2019	60
Kathryn Z. Klaber	Non-Executive Director	1 January 2023	58
Sandra (Sandy) Mary Stash	Non-Executive Director	21 October 2019	64

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, United Kingdom.

3.2 *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

4. Directors' Service Contracts

4.1 Save as disclosed under the section entitled "Service Contracts" (which is incorporated by reference) in the Remuneration Committee's Report of the 2023 Annual Report, there are no existing or proposed service contracts between any Director of the Company and its subsidiary undertakings which provide for any benefits upon termination of employment.

5. Directors' and Senior Managers' Interests

5.1 *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.	1,207,645	2.54%
Non-Executive Directors		
Martin Keith Thomas	112,250	0.24%
Sylvia Kerrigan	1,341	0.00%
David Jackson Turner, Jr.	26,923	0.06%
Kathryn Z. Klaber	1,050	0.00%
Sandra (Sandy) Mary Stash	2,234	0.00%
Senior Managers		
Bradley Grafton Gray	146,947	0.31%
Benjamin M. Sullivan	30,814	0.06%

Notes:

(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 3 below and details of the relevant share option plans are set out in paragraph 3 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.

5.2 *Other interests*

Save as disclosed in paragraphs 5 and 6 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.

6. Share Option Plans

6.1 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 Executive Directors. 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, of which 3,056,030 Ordinary Shares have been issued or transferred from the Company's Employee Benefit Trust (''**EBT**'') as of 31 December 2023.

6.2 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 250 per cent. of the individual's base salary at the date of grant. The vesting of awards granted to Executive Directors 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.

6.3 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 Last Practicable Date, 1,208,012 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.

6.4 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 Last Practicable Date, 1,249,560 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 return on equity, three-year absolute TSR, three-year TSR relative to FTSE 250 Index TSR and three-year methane intensity reduction.

6.5 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 162,108 vested options which have not been exercised. The Company has Share Options under the Share Option Scheme over 152,483 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 11 employees (including the Executive Directors), 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.

6.6 The following options and awards have been granted to the Directors and Senior Managers and remain outstanding as at the Last Practicable Date.

Name	Ordinary Shares subject to the option/award[3]	Exercise period	Exercise price per share (£)
Directors			
Robert Russell "Rusty" Hutson, Jr.	99,269[1]	In one tranche no later than 15 March 2025	
	124,051[1]	In one tranche no later than 31 March 2026	
	243,990[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	25,429[2]	In one tranche no later than 15 March 2025	
	25,429[1]	In one tranche no later than 15 March 2025	
	31,356[2]	In one tranche no later than 31 March 2026	
	31,356[1]	In one tranche no later than 31 March 2026	
	92,639[2]	In one tranche no later than 31 March 2027	
	39,702[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	21,745[2]	In one tranche no later than 15 March 2025	
	21,745[1]	In one tranche no later than 15 March 2025	
	26,359[2]	In one tranche no later than 31 March 2026	
	26,359[1]	In one tranche no later than 31 March 2026	
	75,796[2]	In one tranche no later than 31 March 2027	
	32,484[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*

6.7 Other than 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 shares in the capital of the Company, and the Company has no other convertible securities, exchangeable securities or securities with warrants in issue.

7. Major Shareholders

7.1 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(%)
Columbia Management Investment Advisers	2,394,439	5.03%
Vanguard Group	2,319,898	4.88%
JO Hambro Capital Management	2,238,823	4.71%
GLG Partners	2,091,584	4.40%
BlackRock	2,040,626	4.29%
Abrdn	1,783,144	3.75%
M&G Investments	1,723,692	3.62%
Jupiter Asset Management	1,535,599	3.23%

8. Related Party Transactions

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 years ended 31 December 2023 or during the period from and including 1 January 2024 up to and including the Latest Practicable Date.

9. Material Contracts of the Group

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by members of the Group) (i) within the two years immediately preceding the date of this document which are or may be, material or (ii) which contain any provision under which any member of the Group has any obligation or entitlement which is material to the Group as at the date of this document:

(a) *Membership Interest Purchase Agreement (MIPA)*

Details of the MIPA are set out in Part 3 (*Principal Terms of the Acquisition*) of this document.

(b) *Sponsor Agreement*

On 9 May 2024, the Company and Stifel entered into a sponsor agreement pursuant to which Stifel has agreed to act as the Company's sponsor under the Listing Rules in connection with the Acquisition and the publication of this document (the "**Sponsor Agreement**"). The Sponsor Agreement also provides for the payment of certain fees and expenses by the Company to the Sponsor.

Under the terms of the Sponsor Agreement, the Company has also agreed to provide certain customary warranties, representations and undertakings in favour of the 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 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.

(a) *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.

(b) *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.

(c) *2023 Placing agreement*

On 8 February 2023, the Company, Stifel, Tennyson Securities Limited and Peel Hunt entered into a placing agreement pursuant to which the banks agreed, subject to certain conditions, to use their reasonable endeavours to procure purchasers for the placing shares pursuant to the placing (the "**2023 Placing Agreement"**). The 2023 Placing Agreement also provided for the payment of certain fees, commissions and expenses by the Company to the banks.

Under the terms of the 2023 Placing Agreement, the Company also agreed to provide certain customary warranties, representations and undertakings in favour of the banks in relation to, amongst other things, the accuracy of information in the placing announcement and other matters relating to the

Group. In addition, the 2023 Placing Agreement provides the banks with the right to terminate the 2023 Placing Agreement before admission in certain specified circumstances typical for a placing agreement of this nature.

The Placing Agreement is governed by English law.

(d) *Tanos II Assets purchase and sale agreement*

On 1 February 2023, the Company executed a conditional purchase and sale agreement (the "**Tanos II PSA**") in connection with the acquisition of certain gas and oil wells as well as related midstream infrastructure (the "**Tanos II Assets**") in Texas within the Company's Central Region, from Tanos Energy Holdings II LLC, a portfolio company of Quantum Energy Partners ("**Tanos**"), which was completed on 1 March 2023. The gross cash consideration for this acquisition amounted to $250 million and after customary purchase price adjustments, the total cash consideration paid was approximately $262 million.

The Tanos II PSA is governed by the laws of the state of Delaware, United States.

(e) *Conoco Assets purchase and sale agreement*

On 27 July 2022, the Company executed a conditional purchase and sale agreement (the "**Conoco PSA**") in connection with the acquisition of certain upstream assets and related facilities (the "**Conoco Assets**") in Oklahoma and Texas, within the Company's Central Region, from ConocoPhillips Company ("**Conoco**"), which was completed on 27 September 2022. The gross cash consideration for this acquisition amounted to $240 million and after customary purchase price adjustments, the total cash consideration paid was approximately $210 million.

The Conoco PSA is governed by the laws of the state of Delaware, United States.

(f) *ConServ Assets purchase and sale agreement*

On 26 July 2022, the Company executed an asset purchase agreement (the "**ConServ APA**") in connection with the acquisition of certain well services and plugging assets and operations (the "**ConServ Assets**") from Contractor Services Inc. ("**ConServ**"). The acquisition of the ConServ Assets enhanced the Company's ability to retire more wells, scaled its business to drive further efficiencies in the Company's internal well plugging program and provided additional third-party revenues from other operators and state agencies to offset the Company's own well retirement costs. The ConServ Assets were integrated into the Company's existing Next LVL Energy asset retirement platform. The gross cash consideration for this acquisition amounted to $11.5 million.

The ConServ APA is governed by the laws of the state of West Virginia, United States.

(g) *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.

(h) *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, $9.27 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%.

(i) *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 ESG 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 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 ESG 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.

(j) *ABS IV Notes*

In February 2022, the Group formed Diversified ABS 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 ESG 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 ESG 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.

(k) *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%.

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 ESG 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.

(l) *ABS VI Notes*

In October 2022, the Group formed Diversified ABS 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.

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%.

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 ESG 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.

(m) *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 Class A Notes are rated BBB+ and were issued for an aggregate principal amount of $142 million. The 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.

(n) *ABS Warehouse Facility*

In May 2024, the Group entered into committed financing for an ABS Warehouse Facility (''**ABS Warehouse**'') whereby, upon closing, the ABS Warehouse would provide funding to the Group of $80 million in exchange for placing certain assets within the ABS Warehouse. The ABS Warehouse will be secured by certain upstream assets in the Central Region that were previously secured under the Group's Revolving Credit Facility.

The ABS Warehouse is expected to accrue interest at a floating rate of SOFR + 3.75% rate per annum and have a final maturity date May 2029 with an amortising maturity of October 2031. Interest and principal payments on the ABS Warehouse is payable on a monthly basis.

The ABS Warehouse contains similar affirmative and negative covenants as the Group's existing ABS notes, including based on whether certain performance metrics are achieved. The ABS Warehouse is required to apply 100% of any excess cash flow to make additional principal payments if the DSCR as of the applicable payment date is less than 1.45 to 1.00, or (b) if the production tracking rate for the ABS Warehouse is less than 80%, or (c) if the LTV for ABS VI is greater than 60%.

(o) *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 ESG 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.

The Credit Facility has an interest rate of SOFR plus an additional spread that ranges from 2.75% to 3.75% based on utilization. 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 $11.18 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 >15% (iii) leverage is between 2.0x and 2.5x, free cash flow must be positive and borrowing base availability must be >20% (iv) when leverage exceeds 2.5x for DP RBL Co LLC, restricted payments are prohibited.

Additional covenants require DP RBL Co LLC to maintain a ratio of total debt to EBITDAX 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.

(p) *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.

10. Material Contracts of the Target Assets

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into in connection with the Target Assets (a) in the two years immediately preceding the date of this document and are, or may be, material to the Target Assets or (b) contain provisions under which there is an obligation or entitlement which is material to the Target Assets as at the date of this document:

(a) *Membership Interest Purchase Agreement (MIPA)*

A description of the principal terms of the MIPA is set out in Part 3 ("*Principal Terms of the Acquisition*") of this document.

11. Litigation

(a) ***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.

(b) ***Target Assets***

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 financial position or profitability of the Target Assets.

12. Working capital

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

13. No significant change

(a) ***Group***

There has been no significant change in the financial position or financial performance of the Company or the Group since 31 December 2023, being the end of the last financial period for which financial information of the Group has been published.

(b) ***Target Assets***

There has been no significant change in the financial position or financial performance of the Target Assets since 31 December 2023, being the end of the last financial period for which unaudited financial information of the Target Assets has been presented in Part 4 (*Unaudited Financial Information Relating to the Target Assets*) of this document.

14. Profit Forecast for the Target Assets

14.1 On 19 March 2024, the Company announced, among other things, the proposed Acquisition in accordance with the requirements of the Listing Rules. In that announcement, the Company made the following statements in relation to the financial targets for the Target Assets for the pro forma 12-month period ending 31 December 2024:

- "*Provides robust cash flow with 2024 Adjusted EBITDA of $126 million*"

14.2 The above statement constitutes a profit forecast for the purpose of the Listing Rules. The Profit Forecast relates to the pro forma 12-month period ending 31 December 2024 and relates to Adjusted EBITDA.

Basis of preparation

14.3 The Profit Forecast has been properly compiled on the basis of the assumptions stated below and on a basis which is (i) comparable with the historical financial information of the Group for the year ended 31 December 2023 presented in the 2023 Annual Report (ii) consistent with the accounting policies of the Group, which are in accordance with IFRS and which are those expected by the Group to be applicable for the year ending 31 December 2024.

14.4 The Directors have prepared the Profit Forecast on the basis of the following assumptions in relation to the Target Assets:

- annual production of natural gas of 36,156 MMcf;
- annual production of oil of 619 Mbbl;
- annual production of NGL of 818 Mbbl;
- an average sales price per of natural gas of $1.96 per MMcf;
- an average sales price per of oil of $77.10 per bbl;
- an average sales price per of NGL of $26.20 per bbl;
- gain on derivative financial instruments for the year of $51,816,000; and
- operating costs for the year of $65,852,000.

14.5 The Directors have considered and confirm that the Profit Forecast remains correct as at the date of this document.

Factors outside the influence or control of the Board:

Factors outside the control of the Board include the following, which may have a detrimental effect on the sales prices of natural gas, oil and LNG achievable:

- political instability, either within the United States or internationally;
- operational disruptions or interruptions of service by third party midstream companies or other contractor service companies;
- regulatory changes by local, state or federal governments;

- inflationary cost increases;
- natural disasters; and
- global pandemics

Factors within the influence or control of the Board:

Factors within the control of the Board include:

- the daily production levels of natural gas, oil and LNG at the Target Assets; and
- operating expenditure in relation to the Target Assets.

15. Miscellaneous

15.1 There have been no material changes since the date of the CPR on the Target Assets, the omission of which would make such report misleading.

15.2 NSAI has given and has not withdrawn its written consent to the inclusion in this document of the CPR on the Target Assets set out in Part 5 ("*CPR on the Target Assets*") of this document, and the references thereto and to its name in the form and context in which it appears. The CPR on the Target Assets was prepared at the request of the Company. NSAI has no interest in the share capital of the Company nor any member of the Group.

15.3 Crowe U.K. LLP, whose address is 55 Ludgate Hill, London ECM 7JW, 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 6 ("*Unaudited Pro Forma Financial Information*") of this document of its report on the unaudited pro forma financial information, in each case, as set out in in the form and context in which it is included. Crowe U.K. LLP is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales (under registration number C001095468) and the Financial Reporting Council. Save for the remuneration payable in respect its role as reporting accountant to the Company, Crowe U.K. LLP does not have a material interest in either the Company or Oaktree Capital Management, L.P.

15.4 Stifel has given and has not withdrawn its written consent to the inclusion in this document of the references to its name in the form and context in which it appears.

15.5 Statutory consolidated accounts of the Company have been delivered to the Registrar of Companies in respect of the financial year ended 31 December 2023 and an independent auditors' report was made on those accounts. The auditors gave an unqualified opinion in respect of the financial year ended 31 December 2023. 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.

16. Documents incorporated by reference

The contents of the Company'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 Shareholders should not rely upon them.

Details of documentation incorporated into this document by reference are explained in Part 8 ("*Documents Incorporated by Reference*").

17. Documents available for inspection

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 up to and including the date of the General Meeting at the Company's registered office at 4th Floor Phoenix House, 1 Station Hill, Reading, Berkshire, United Kingdom, RG1 1NB:

(a) the Articles;

(b) the accountants' report by Crowe U.K. LLP on the unaudited pro forma financial information set out in Section B of Part 6 ("*Unaudited Pro Forma Financial Information"*);

(c) copies of the letters of consent referred to in paragraphs 15.2, 15.3 and 15.4 of this Part 7 ("*Additional Information*");

(d) the MIPA;

(e) the 2023 Annual Report; and

(f) this document.

Copies of the above documents (other than the MIPA) will also be published on the Company's website at https://ir.div.energy/.

Part 8
DOCUMENTS INCORPORATED BY REFERENCE

The table below sets out the documents of which certain parts are incorporated by reference into, and form part of, this document. The parts of these documents which are not incorporated by reference are either not relevant for Shareholders 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 LR 13.1.3R. 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 17 of Part 7 ("*Additional Information*") of this document.

Reference Document	*Information Incorporated by reference*	*Page number in the reference documents*
2023 Annual Report	Corporate Governance – The Remuneration Committee's Report – Service Contracts	118-119

Part 9
TECHNICAL TERMS

"annual decline rate"	the annualised rate at which oil and gas production volumes decline;
"average remaining producing life"	the average time period of future production capability of the Company's portfolio of wells;
"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;
"Best Estimate"	the middle value in a range of estimates considered to be the most likely. If based on a statistical distribution, this can be the mean, median or mode depending on usage;
"Bcf"	billion cubic feet;
"Bcfe"	billion cubic feet of natural gas equivalent;
"boe"	barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 6,000 cf of natural gas;
"boepd"	barrels of oil equivalent per day;
"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;
"development well"	a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive in an attempt to recover proved undeveloped reserves;
"Mcf"	thousand standard cubic feet of natural gas;
"Mcfe"	thousand cubic feet of natural gas equivalent;
"Mcfed"	thousand cubic feet of natural gas equivalent per day;
"Mbbl"	thousand barrels of oil;
"Mboe"	thousands of barrels of oil equivalent;
"Mboed"	thousands of barrels of oil equivalent per day;
"MMboe"	millions of barrels of oil equivalent;
"MMbtu"	million btus;
"MMcf"	million standard cubic feet of natural gas;
"MMcfe"	million standard cubic feet of natural gas equivalent;
"MMcfed"	million standard cubic feet of natural gas equivalent per day;
"PV10"	the present value of a future sum of money or stream of cash flows given a discount rate 10 per cent. PV10 is a customary valuation metric used in the valuation of future cash flows for oil and gas reserves;
"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;
"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.);
"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; and
"West Texas Intermediate"	the underlying commodity of the Chicago Mercantile Exchange's oil futures contracts.

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 December 2023;
"2023 Placing Agreement"	a placing agreement dated 8 February 2023 entered into by the Company, Stifel, Tennyson Securities Limited and Peel Hunt;
"ABS I"	Diversified ABS LLC;
"ABS II"	Diversified ABS II LLC;
"ABS III"	Diversified ABS III LLC;
"ABS IV"	Diversified ABS IV LLC;
"ABS V"	Diversified ABS V LL;
"ABS VI"	Diversified ABS VI LLC;
"ABS VII"	DP Lion Equity Holdco LLC;
"ABS Warehouse Facility"	the ABS Warehouse Facility, as described in section 8.1(n) of Part 7 of this Circular;
"Acquisition"	the proposed acquisition of the Target Assets by the Company from the Seller pursuant to the MIPA;
"Adjusted EBITDA"	earnings before interest, taxes, depletion, depreciation and amortisation and adjustments for non-recurring items such as gain on the sale of assets, acquisition related expenses and integration costs, mark-to-market adjustments related to the Company's hedge portfolio, non-cash equity compensation charges and items of a similar nature;
"Articles"	the articles of association of the Company, as amended from time to time;
"Bluegrass"	DP Bluegrass LLC;
"Board"	the board of directors of the Company from time to time including a duly constituted committee thereof;
"Business Day"	any day except a Saturday, Sunday or legal holiday in the State of New York or in London;
"Central Region PSA"	a purchase and sale agreement entered into on 17 April 2023 in connection with the divestment of certain non-operated wells in Oklahoma and Texas by the Company;
"certificated" or "in certificated form"	a share or other security which is not in uncertificated form (that is, not in CREST);
"Class 1 condition"	approval by the shareholders of the Company of the transactions contemplated by the MIPA in accordance with the requirements of the Listing Rules;
"Companies Act 2006"	the Companies Act 2006 (as amended);
"Company"	Diversified Energy Company PLC;

"Completion"	completion of the Acquisition in accordance with the MIPA;
"Conditions"	the conditions to the Acquisition, as described in paragraph 3 of Part 3 ("*Principal Terms of the Acquisition*");
"Conoco Assets"	certain upstream assets and related facilities in Oklahoma and Texas operations acquired by the Company under the Conoco PSA;
"Conoco PSA"	a conditional purchase and sale agreement dated 27 July 2022 entered into by the Company in connection with the acquisition of certain upstream assets and related facilities in Oklahoma and Texas, within the Company's Central Region, from ConocoPhillips Company;
"Conoco"	ConocoPhillips Company;
"ConServ APA"	an asset purchase agreement dated 26 July 2022 entered into by the Company in connection with the acquisition of certain well services and plugging assets and operations from Contractor Services;
"ConServ Assets"	certain well services and plugging assets and operations acquired by the Company under the ConServ APA;
"ConServ"	Contractor Services Inc.;
"Consideration"	the consideration payable by the Company to the Seller pursuant to the terms of the MIPA, as set out in Part 1 of this document;
"CPR on the Target Assets"	the mineral expert report prepared by NSAI contained in Part 5 ("*CPR on the Target Assets*") of this document;
"Credit Facility"	the revolving loan facility with KeyBank, National Association and certain other lenders, as set out in paragraph 8.1(n) of Part 7 of this document;
"CREST Manual"	the rules governing the operation of CREST, consisting of the CREST reference Manual, CREST International Manual, CREST Central Counterparty Service Manual, CREST Rules, Registrars Service Standards, Settlement Discipline Rules, CCSS Operations Manual, Daily Timetable, CREST Application Procedure and CREST Glossary of TERMS (all as defined in the CREST Glossary of Terms promulgated by Euroclear UK & Ireland on 15 July 1996 and as amended since);
"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 & Ireland is the Operator (as defined in such Regulations) in accordance with which securities may be held and transferred in uncertificated form;
"Depositary"	Computershare Investor Services PLC, in its capacity as the issuer of the Depositary Interests;
"Depositary Interest" or "DIs"	a Depositary Interest issued through CREST by the Depositary, representing a beneficial interest in a Share;
"Depositary Interest Holder"	the holders of Depositary Interests;
"Depositary Interest Custodian"	Computershare Trust Company NA;
"DGOC"	Diversified Gas & Oil Corporation, a wholly owned subsidiary of the Company;

"Directors"	the directors of the Company, whose names are set out in paragraph 3 of Part 7 ("*Additional Information*") of this document;
"Diversified Production"	Diversified Production LLC, a subsidiary of the Company;
"DSCR"	debt service coverage ratio;
"DTRs"	the Disclosure Guidance and Transparency Rules made by the FCA pursuant to Part 6 of FSMA;
"East Texas Acquisition"	acquisition by the Company of certain East Texas upstream assets and related facilities from a private seller for a net consideration of $50 million;
"East Texas Assets"	certain East Texas upstream assets and related facilities operations acquired by the Company pursuant to the East Texas Acquisition;
"EBITDA"	earnings before interest, tax, depreciation and amortisation;
"EBT"	Employee Benefit Trust;
"Effective Time"	1 November 2023;
"Enlarged Group"	the Group following Completion;
"Equity Incentive Plan"	Diversified Gas & Oil PLC 2017 Equity Incentive Plan, as amended and restated on 27 April 2021;
"Euroclear UK & Ireland"	Euroclear UK & Ireland Limited, the operator of CREST;
"FCA"	the Financial Conduct Authority;
"Form of Instruction"	the Form of Instruction for use by Depositary Interest Holders voting at the General Meeting;
"Form of Proxy"	the form of proxy accompanying this document for use by Shareholders in relation to the General Meeting;
"FSMA"	the UK Financial Services and Markets Act 2000 (as amended);
"General Meeting"	the general meeting of the Company to be held at the offices of FTI Consulting, 200 Aldersgate, Aldersgate Street, London, EC1A 4HD, United Kingdom on 28 May 2024 at 1 p.m. (London time) (or any adjournment thereof, notice of which is set out at the end of this document);
"Group"	the Company and its subsidiary undertakings as at the date of this document;
"ICMA"	the International Capital Markets Association;
"IFRS"	UK-adopted international accounting standards pursuant to The Prospectus (Amendments etc.) (EU Exit) Regulations 2019;
"Indigo Acquisition"	acquisition by the Company of certain Cotton Valley upstream assets and related facilities primarily in the state of Louisiana from Indigo Minerals LLC for a gross consideration of $135 million;
"Indigo Assets"	certain Cotton Valley upstream assets and related facilities primarily in the state of Louisiana acquired by the Company pursuant to the Indigo Acquisition;
"KPIs"	key performance indicators;

"Latest Practicable Date"	7 May 2024, being the latest practicable date before publication of this document;
"LEI"	Legal Entity Identifier;
"Listing Rules"	the rules and regulations made by the FCA in its capacity as the UK Listing Authority under the FSMA, and contained in the UK Listing Authority's publication of the same name;
"London Stock Exchange"	London Stock Exchange plc;
"Long Stop Date"	the date on or before which MIPA may be terminated by either the Group or the Seller if the Completion has not occurred;
"MIPA"	the membership interest purchase agreement dated 18 March 2024 described in Part 3 ("*Principal terms of the Acquisition*") of this document;
"Nomination Committee"	the duly constituted nomination and governance committee of the Board;
"Non-Operated Central Region Assets"	certain non-operated wells in Oklahoma and Texas;
"Notice of General Meeting" or "Notice"	the notice of the General meeting which is set out at the end of this document;
"NSAI"	Netherland, Sewell & Associates, Inc.;
"Oaktree"	Oaktree Capital Management, L.P.;
"Oklahoma Acreage APA"	an asset purchase agreement entered into by the Company on 12 July 2023 in connection with the divestment of certain undeveloped acreage in Oklahoma within the Company's Central Region by the Company;
"Ordinary Shares"	the ordinary shares of 20 pence each in the capital of the Company;
"Pro Forma Financial Information"	the unaudited pro forma Statement of Financial Position as at 31 December 2023 and the unaudited pro forma Statement of Comprehensive Income for the year then ended;
"Profit Forecast"	the profit forecast in relation to the Target Assets as described in Part 1 and Part 7 of this document;
"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;
"PSUs"	performance stock units awarded by the Company to certain employees under the Equity Incentive Plan;
"Registrars"	Computershare Investor Services PLC;
"Regulatory Information Service" or "RIS"	any of the services authorised by the FCA from time to time for the purpose of disseminating regulatory announcements;
"Resolution"	the ordinary resolution as set out in the Notice of General Meeting;
"RSUs"	restricted stock units awarded by the Company to certain employees under the Equity Incentive Plan;
"Seller"	OCM Denali Int Holdings PT, LLC, a subsidiary of Oaktree Capital Management, L.P.;

"Shareholders"	the holders of the Ordinary Shares;
"Smarter Asset Management"	precautionary techniques for extending well life that include wellhead compression management, fluid load deduction and pumpjack optimization;
"Sponsor Agreement"	the sponsor agreement between the Company and the Sponsor dated 9 May 2024;
"Sponsor" or "Stifel"	Stifel Nicolaus Europe Limited;
"SPTs"	sustainability performance targets;
"Strategic Partnership Agreement"	the strategic partnership agreement dated 5 October 2020 between the Group and Oaktree to jointly identify and fund future proved developed producing acquisition opportunities that the Group would identify over a three-year period;
"Tanos Acquisition"	acquisition by the Company of certain Cotton Valley and Haynesville upstream assets and related facilities in the states of Louisiana and Texas from Tanos Energy Holdings III LLC for a gross consideration of $154 million, which was completed on 18 August 2021;
"Tanos Assets"	certain Cotton Valley and Haynesville upstream assets and related facilities in the states of Louisiana and Texas;
"Tanos II Assets"	certain gas and oil wells as well as related midstream infrastructure in Texas within the Company's Central Region;
"Tanos II PSA"	a conditional purchase and sale agreement entered into by the Company on 1 February 2023 in connection with the acquisition of certain gas and oil wells as well as related midstream infrastructure in Texas within the Company's Central Region, from Tanos Energy Holdings II LLC, a portfolio company of Quantum Energy Partners;
"Tanos"	Tanos Energy Holdings II LLC, a portfolio company of Quantum Energy Partners;
"Tapstone Acquisition"	acquisition by the Company of certain upstream assets, field infrastructure, equipment and facilities within the Company's Central Region from Tapstone Energy Holdings, LLC and its related party - KL CHK SPV, LLC for a net consideration of $181 million, which was completed on 8 December 2021;
"Tapstone Assets"	certain upstream assets, field infrastructure, equipment and facilities within the Company's Central Region acquired by the Group pursuant to the Tapstone Acquisition;
"Target Assets' Financial Information"	the unaudited summary trading results of the Target Assets' for the two years ended 31 December 2022 and 31 December 2023, as set out in Part 4 of this document;
"Target Assets"	Oaktree's current proportionate working interest in each of the Indigo Assets, the Tanos Assets, the Tapstone Assets and the East Texas Assets, as set out in Part 1 of this document;
"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;

"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;
"Undeveloped Oklahoma Acreage Assets"	certain undeveloped acreage in Oklahoma;
"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; and
"US$" or "$" or "USD" or "US dollars"	US dollars, the lawful currency of the United States.

NOTICE OF GENERAL MEETING

Diversified Energy Company PLC

(Registered in England and Wales with registered number 09156132)

NOTICE IS HEREBY GIVEN that the General Meeting of the Company will be held at the offices of FTI Consulting, 200 Aldersgate, Aldersgate Street, London, EC1A 4HD, United Kingdom at 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 28 May 2024 for the purpose of considering and, if thought fit, passing the Resolution.

ORDINARY RESOLUTION: Approval of the Acquisition

That the proposed acquisition of 100% of the limited liability company interests of OCM Denali INT Holdings PT, LLC, a subsidiary of Oaktree Capital Management, L.P., in OCM Denali Holdings to be effected by the Company as described in the circular to shareholders of the Company dated 9 May 2024 of which the Notice convening this General Meeting forms part (the ''**Circular**''), on the terms and subject to the conditions of the MIPA (as defined in the Circular) and the associated and ancillary arrangements contemplated by the MIPA, be approved, and the directors of the Company (the ''**Directors**'') (or any duly constituted committee of the Directors) be and are hereby authorised to take all such steps as may be necessary, expedient or desirable in relation thereto and to carry the same into effect with such modifications, variations, revisions, waivers or amendments to such agreements or any documents relating thereto as they shall deem necessary, expedient or desirable (providing such modifications, variations, revisions, waivers or amendments do not materially change the terms of the proposed acquisition for the purposes of Financial Conduct Authority's Listing Rule 10.5.2).

Registered Office: By Order of the Board

4th Floor Phoenix House
1 Station Hill, Reading
Berkshire, RG1 1NB
United Kingdom

Dated: 9 May 2024

Apex Secretaries LLP
Company Secretary

NOTES TO THE NOTICE OF GENERAL MEETING

1. Only those Shareholders registered in the Company's register of members at close of business on 23 May 2024 or if this meeting is adjourned, close of business on the date which is two business days prior to the time of the adjourned meeting for shareholders, shall be entitled to vote at the meeting. Changes to the register of members after the relevant deadline shall be disregarded in determining the rights of any person to attend and vote at the meeting.

2. Depositary Interest Holders registered in the register of Depositary Interests at close of business on 21 May 2024, or if this meeting is adjourned, close of business on the date which is four business days prior to the time of the adjourned meeting for shareholders shall be entitled to are entitled to provide voting instructions to Computershare Investor Services PLC ("**Computershare**") in respect of the number of U.K. Depositary Interests registered in their name(s) at that time.

3. If you hold your interest through a broker, bank, or nominee (or similar), you should normally receive directions from such broker, bank, or nominee (or similar) on how to (electronically or in person) attend and vote at the General Meeting or how to give a proxy or voting instructions. These directions should be followed. If you have not received such directions, it would be advisable to contact your broker, bank, or nominee (or similar) as soon as possible.

4. If a Depositary Interest Holder or a representative of that holder wishes to attend the General Meeting and/or vote at the General Meeting, they must contact the Depositary, Computershare Investor Services PLC, with a Letter of Representation from their broker or nominee and provide this letter by email to !UKALLDITeam2@computershare.co.uk by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 21 May 2024. On receipt, the Depositary will issue a separate Letter of Representation authorising attendance on behalf of the Depositary Interest Custodian, Computershare Trust Company NA. The Depositary Interest Holder or a representative of that holder should present the original Letter of Representation upon attendance at the General Meeting in order to gain entry to the General Meeting. DI Holders that do not follow the above process will be unable to represent their position in person at the General Meeting. The completion of the Form of Instruction will not preclude a holder from attending the General Meeting and participating once such Letter of Representation has been issued.

5. Information regarding the meeting can be found at https://ir.div.energy/reports-announcements.

6. Any Shareholder entitled to attend and vote at the General Meeting is entitled to appoint one or more proxies (who need not be a member of the Company) to attend and to vote instead of the member. Completion and return of a Form of Proxy will not preclude a Shareholder from attending and voting at the meeting in person, should he or she subsequently decide to do so.

7. If you are a Shareholder who is entitled to attend and vote at the meeting, you are entitled to appoint one or more proxies to exercise all or any of your rights to attend, speak and vote at the meeting and you should have received a Form of Proxy with this Notice. This form cannot be used by Depositary Interest Holders who will have been sent a Form of Instruction. Shareholders can only appoint a proxy using the procedures set out in these notes and the notes to the Form of Proxy. If you appoint multiple proxies and wish to give them separate instructions to vote or abstain from voting, please indicate how you wish each proxy to vote or abstain from voting on the reverse side of each proxy card on which you have entered the name of your proxy. For the avoidance of doubt, where multiple proxies are appointed, each proxy must be appointed to exercise the rights attached to a different share or shares held by you. All forms must be signed and should be returned together in the same envelope to 'Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717'.

8. To be valid, an appointment of proxy must be returned by one of the following methods:

   a. For a Shareholder, an instrument appointing a proxy and any power of attorney or other authority under which the proxy instrument is signed (or a notarially certified copy thereof) must be deposited with Broadridge Financial Solutions, Inc. at Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717 by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024;

   b. Alternatively, register your vote online by visiting www.proxyvote.com using the 16-digit control number (your "**Control Number**") set out in the Form of Proxy and following the instructions provided by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024; or

c. Depositary Interest Holders can provide an instruction by utilising the CREST electronic voting instruction service in accordance with the procedures set out below.

9. Depositary Interest Holders may direct Computershare to vote the Shares represented by their Depositary Interests as follows:

   a. Mail: Complete and return a Form of Instruction to Computershare using the reply-paid envelope that accompanied the Form of Instruction or by posting it to Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol, BS99 6ZY, United Kingdom. To be effective, all Forms of Instruction must be received by Computershare by 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 22 May 2024. Computershare, as your proxy, will then make arrangements to vote your underlying Shares according to your instructions.

   b. CREST: Depositary Interest Holders who wish to instruct their Custodian on how to vote through the CREST electronic proxy appointment service may do so for the General Meeting and any adjournment thereof by using the procedures described in the CREST manual. CREST personal members who have appointed a voting service provider(s) should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf. In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a CREST Proxy Instruction) must be properly authenticated in accordance with Euroclear UK & International Limited's specifications and must contain the information required for such instructions, as described in the CREST manual. All messages relating to the appointment of a proxy or an instruction to a previously appointed proxy must be transmitted so as to be received by Computershare (ID: 3RA50) no later than 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 22 May 2024. Normal system timings and limitations will apply in relation to the input of CREST Proxy Instructions. It is therefore the responsibility of the CREST member concerned to take such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable their CREST sponsor(s) or voting service provider(s) are referred, in particular, to those sections of the CREST manual concerning practical limitations of the CREST system and timings. The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Uncertificated Securities Regulations 2001 as amended.

10. A vote abstention is not a vote in law, which means that the vote will not be counted in the calculation of votes for or against the Resolution. If no voting indication is given, your proxy may vote or abstain from voting at his or her discretion. Your proxy may vote (or abstain from voting) as he or she thinks fit in relation to any other matter which is put before the meeting.

11. In the case of joint holders, where more than one of the joint holders completes a proxy appointment, only the appointment submitted by the most senior holder will be accepted. Seniority is determined by the order in which the names of the joint holders appear in the Company's register of members in respect of the joint holding (the first named being the most senior).

12. Shareholders and Depositary Interest Holders may change proxy instructions by submitting a new voting instruction using the methods set out above, as applicable.

13. Where you have appointed a proxy using the hard-copy Form of Proxy and would like to change the instructions using another hard-copy Form of Proxy, please contact Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717.

14. If you submit more than one valid proxy appointment, the appointment received last before the latest time for the receipt of proxies will take precedence.

15. A Shareholder may change a proxy instruction but to do so you will need to inform the Company in writing by sending a signed hard-copy notice clearly stating your intention to revoke your proxy appointment to Computershare. In the case of a Shareholder which is a company, the revocation notice must be executed under its common seal or signed on its behalf by an officer of the company or an attorney for the company. Any power of attorney or any other authority under which the revocation notice is signed (or a duly certified copy of such power or authority) must be included with the revocation notice.

16. In either case, the proxy revocation notice must be received by Broadridge Financial Solutions, Inc. at Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717 by no later than 1.00 p.m. (London time) / 8.00 a.m. (New York time) on 23 May 2024.

17. If you attempt to revoke your proxy appointment but the revocation is received after the time specified, your original proxy appointment will remain valid unless you attend the meeting and vote in person.

18. Beneficial owners should contact their broker, bank or other holder of record for instructions on how to revoke their proxies or change their vote. Depositary Interest Holders should contact Computershare for instructions on how to revoke their proxies or change their vote.

19. A corporation which is a Shareholder can appoint one or more corporate representatives who may exercise, on its behalf, all its powers as a Shareholder provided that no more than one corporate representative exercises powers over the same Share.

20. Any validated member attending the meeting has the right to ask questions. The Company must answer any question you ask relating to the business being dealt with at the meeting unless:

    a. answering the question would interfere unduly with the preparation for the meeting or involve the disclosure of confidential information;

    b. the answer has already been given on a website in the form of an answer to a question; or

    c. it is undesirable in the interests of the Company or the good order of the meeting that the question be answered.

21. Copies of the MIPA and documents as set out in paragraph 17 of Part 7 ("*Additional Information*") of the Circular are available for inspection at the Company's Registered Office during normal business hours and at the place of the meeting from at least 15 minutes prior to the meeting until the end of the meeting.

22. The quorum for the meeting is two or more members, who are entitled to vote, present in person or by proxy or a duly authorised representative of a corporation which is a member.

23. At the meeting the vote may be taken by show of hands or by poll. On a poll, every member, who is present in person or by proxy, shall be entitled to one vote for every Share held by him.

24. If, within five minutes after the time appointed for the meeting (or such longer interval not exceeding one hour as the Chair of the meeting may think fit to allow) a quorum is not present, the meeting shall stand adjourned to a day (but not less than 10 days later, excluding the day on which the meeting is adjourned and the day for which it is reconvened) the time and place to be decided by the Chair, and if at such adjourned meeting a quorum is not present within half an hour from the time appointed for the meeting, the members present in person and by proxy shall be a quorum.